How to include CCS in the CDM? Baseline methodologies and institutional implications.

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Disclaimer

Findings and recommendations in this report reflect views of the authors only and do not necessarily coincide with the position from the European Commission in respect of the need to include CO_2 capture and storage in the Clean Development Mechanism or ways to achieve this.

Abstract

The inclusion of CO_2 capture and storage (CCS) in the Clean Development Mechanism (CDM) has turned out highly controversial. A range of concerns will need to be addressed to ensure safety and greenhouse gas integrity of CCS operations under the CDM, notably related to the integrity of geological storage sites, monitoring and site development, and long-term liability. This report consists of two parts.

In Part A, two routes are explored to enable CCS in the CDM. Firstly, dilemmas encountered in the development of baseline methodologies for CCS projects are discussed, including problems related to the energy penalty, changes in the load factor of retrofit plants, and an increased consumption of fossil fuels from enhanced hydrocarbon recovery operations. Secondly, a number of institutional arrangements will be necessary to guarantee long term storage of CO_2. These include the establishment of a CCS panel to evaluate compliance with requirements for site selection, monitoring and site development. Such requirements may be laid down in a COP/MOP decision and - in more detail - in the applicability conditions of baseline methodologies. Furthermore, a special accreditation for Designated Operational Entities (DOEs) validating and verifying potential CCS projects under the CDM is recommended.

In Part B three illustrative baseline methodologies for hypothetical CCS operations under the CDM are elaborated using a template provided by the UNFCCC Secretariat. The hypothetical CCS operations included (1) capture of CO_2 from a coal-fired power plant and its use in a newly developed enhanced coal bed methane recovery; (2) capture of CO_2 from a newly built pulverized coal plant and its subsequent storage in depleted oil or gas fields or saline formations; and (3) capture of CO_2 from a natural gas processing plant and its storage in depleted oil or gas fields or saline formations. Furthermore, three annexes to each of these three illustrative methodologies are proposed that hold suggested applicability conditions for the methodologies. They comprise requirements and criteria with respect to site selection, monitoring, site development and liability.

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Part A: Dilemmas in baseline methodologies and institutional implications

1. Introduction

CO_2 capture and storage (CCS) is considered by many an important option to reduce greenhouse gas emissions to sustainable levels (IEA, 2008). World primary energy demand until 2030 is projected to grow by more than half over the 2005 level, and due to their availability and relatively lower costs, fossil fuels will remain the dominant source. The share of coal in global primary energy consumptions has been projected to grow from 25% to 28%, with an absolute increase of 73% until 2030 (IEA, 2007). Inclusion of CCS in the Clean Development Mechanism (CDM) could be a way to provide an incentive to those CCS project types that are ready to be deployed at a commercial scale. Note that so far the CDM has not contributed to the support of any technology in the demonstration phase.

However, the issue has turned out to be highly controversial in recent climate negotiations (de Coninck, 2008). At COP/MOP3 in Bali in December 2007, the Subsidiary Body for Scientific and Technological Advice (SBSTA) at its 27th session agreed to request the UNFCCC Secretariat to prepare a synthesis report of previous submissions on CCS in the CDM for further consideration at SBSTA28. In this report[1], objections raised to the inclusion of CCS in the CDM can be divided into three categories:

Objections to the technology itself
CCS is a relatively novel technology surrounded by risks distinct from those connected to many other energy and industrial technologies. Concerns in this respect regard in particular site integrity and permanence of the CO_2 storage. Some opponents have argued that industrialised countries should take the lead in mitigating climate change and developing the necessary technologies. The technology was also considered too expensive for many non-Annex I countries. An associated issue that has been raised concerns the liability which would pass on from a private party to the host country, which may lack the financial means to properly deal with this liability. Thus, this would imply a hidden transfer of cost from developed to developing countries.

Objections on the grounds of incompatibility with the objectives of the CDM
A second category of concerns regards the character of the CDM, which was designed to enhance sustainable development in non-Annex I countries. Whether CCS fits into a sustainable development picture is contested, partly because it is a large scale high-tech option from which local communities would benefit very little and also because it would allow for the continued use of fossil fuels, which is considered unsustainable in the long run.

Objections relating to the implications for other technology and Party Commitments
CCS would compete with renewable energy and energy efficiency opportunities under the CDM. It could also get in the way of non-Annex I countries taking on commitments of their own under a post-2012 regime. This is because these countries would not be able to use Certified Emission Reductions (CERs) of CCS operations on their territories for complying with their own climate targets. Instead, the industrialised world would use these CERs to comply with its commitments.

In Bali, SBSTA (through the COP) also invited Parties to submit their views on ways forward in respect of a range of issues, including:

a) Long-term physical leakage (seepage) levels of risks and uncertainty (discussed in Section 2.8 of this report).

[1] FCCC/SBSTA/2008/INF.1.

b) Project boundary issues (such as reservoirs in international waters or several projects using one reservoir) and projects involving more than one country (projects that cross national boundaries) (Section 2.3).
c) Long-term responsibility for monitoring the reservoir and any remediation measures that may be necessary after the end of the crediting period (Section 2.10).
d) Long-term liability for storage sites (Section 2.10).
e) Accounting options for any long-term leakage (seepage) from reservoirs (Section 2.8).
f) Criteria and steps for the selection of suitable storage sites with respect to the potential for release of greenhouse gases (GHGs) (Section 2.5).
g) Potential leakage paths and site characteristics and monitoring methodologies for physical leakage (seepage) from the storage site and related infrastructure, for example, transportation (Section 2.5).
h) Operation of reservoirs (for example, well-sealing and abandonment procedures), dynamics of carbon dioxide (CO_2) distribution within the reservoir and remediation issues (Section 2.10).
i) Any other relevant matters, including environmental impacts.

Other relevant matters (point i) may include for instance the additionality of CCS projects (Section 2.1), calculation of baseline emissions (Section 2.4), the energy penalty (Section 2.6), a change in load factor (Section 2.7), increased fossil fuel use (Section 2.9). Parties' views on the above list of issues were collected in another UNFCCC report, issued in September 2007. [2]

This report sets out to explore ways to enable CCS under the CDM, and to address the issues listed above. While some of the objections may be accommodated partly by designing some other mechanism alongside the CDM tailored to the specific problems of CCS, this would require a dedicated institutional set-up. It seems reasonable to firstly assess extensively the possibilities and problems of using the CDM to provide an incentive for CO_2 capture and storage in developing countries.

In order to explore the controversial issues related to additionality and emissions accounting of CDM project activities using CCS, three illustrative CDM baseline methodologies for hypothetical projects were developed. The three projects are:
- Capture of CO_2 from an *existing coal-fired power plant* and its use in a newly developed *enhanced coal bed methane recovery* operation.
- Capture of CO_2 from a newly built pulverised coal plant, excluding plants co-firing biomass, and its subsequent storage in depleted oil or gas fields or saline formations.
- Capture of CO_2 from a natural gas processing plant and storage in depleted oil or gas fields or saline formations.

The methodologies have been included in Part B of this report. During the elaboration of the methodologies, a number of dilemmas were encountered, and the most important and fundamental ones are outlined below. Based on the findings obtained during the elaboration of these hypothetical methodologies, Part A uses two routes to explore the intricacies of CCS operations with CDM practices and structures.

Firstly, a number of concerns may be accommodated through the regular CDM baseline methodologies and additionality tools. Aspects of CCS projects bear resemblance to aspects of other CDM projects, such as projects for new, more energy-efficient fossil fuel fired power plants, for which the CDM Methodologies Panel has approved a consolidated baseline methodology (ACM0013). However, even after using the opportunities that the CDM offers, CCS projects still have a number of technical issues, including additionality, the calculations of baseline emissions, the energy penalty, changes in the load factor of a plant, and increase fossil fuel use following CO_2 use in enhanced hydrocarbon recovery operations.

[2] FCCC/SBSTA/2008/INF.3.

Secondly, a number of institutional modifications are suggested that would be necessary to allow for the sound treatment of CCS under the CDM framework, that ensure that CCS operations under the CDM are operated safely and that concerns regarding greenhouse gas integrity of the project as well as for the local environment, human health and safety are being addressed.

This twin track approach is reflected in the structure of this report. Section 2 outlines approaches to the issues listed above in respect of CCS inclusion in the CDM. Most of these can be dealt with by a number of fundamental choices that need to be made in the design of a CDM baseline methodology for CCS operations. The arguments are based on discussions held throughout the development of three illustrative CDM methodologies for hypothetical CCS operations, annexed to this report. While CCS in non-power sectors is important as well, the argument in this section emphasises the issues encountered in the baseline methodologies for power plants. Section 3 continues with a number of institutional arrangements that would seem necessary to ensure the greenhouse gas integrity of CCS operations under the CDM. In particular, it suggests an expert panel for CCS under the CDM Executive Board, and special accreditation for DOEs for CCS. In Section 4 we conclude on the controversial issues in the CCS CDM debate that in our view can be dealt with adequately in baseline methodologies, and outstanding issues for which a solution will need to be negotiated by the Parties to the UNFCCC Convention.

2. Dilemmas in CCS baseline methodologies

Emission reductions from a CDM project must be measurable and additional to any emission reductions that would have occurred in absence of the project activity. To establish additionality the project emissions must be compared to the emissions in the baseline scenario. The baseline is established by the project developer according to approved methodologies. If the project developer prefers to use a new methodology to calculate baseline emissions, it must first be approved by the Executive Board. A range of dilemmas needs to be resolved while elaborating a CCS baseline methodology, and they are discussed in the following.

2.1 Demonstration of additionality

2.1.1 Which additionality tools should be used?

Two distinct tools have been developed by the CDM Executive Board to test the additionality of CDM projects, namely the ‘Tool for demonstration of additionality’, and the ‘Combined tool for demonstration of additionality and baseline methodology’. With respect to power plants, these tools prescribe that plausible alternative scenarios should include all possible realistic and credible alternative options that provide outputs or services comparable with the new built or retrofitted project plant, i.e. all types of power plants that could be constructed as an alternative to provide baseload power within the project boundary.

The applicability conditions of named additionality tools differ. The conditions of the combined tool stipulate that methodologies using the combined tool are only applicable if all potential alternative scenarios to the proposed project activity are available options to project participants. The second tool applies for projects where not all alternative scenarios are available to the project developer.

Retrofits consist of modifications to an existing installation that is operated by project participants. For any alternative scenario to an existing installation the operator of the installation will be key, as it will be the operator who will decide on modifications for the plant. Therefore, we suggest using the combined tool for retrofits.

For new built operations, we recommend using the ‘Tool for demonstrations of additionality’. New built operations will include also scenarios that may not be available to project participants. For instance, the construction of a wind mill park instead of a fossil fuel power plant with CCS may not be part of the core business or the expertise of the project developer, and may require the involvement of other parties. Therefore, the combined tool is not suitable in such a case.

Obviously, the availability of alternatives to the project developer and the implied choices for either the tool or the combined tool will need to be evaluated on a case by case basis. The distinction between retrofits and new built operations with respect to the additionality tools is also applicable to natural gas processing operations.

In general, we recommend that for CCS projects alternatives would need to be identified for:
- In the case of a power generation project, the way power would be generated in absence of the project activity.
- The fate of the CO_2 in absence of the project activity.
- The state of the storage complex in absence of the project activity.

2.2 How may additionality be demonstrated in the CDM PDD?

Realistic and credible alternative scenarios must be identified in the CDM Project Design Document (PDD). These would reflect plausible alternatives that are in line with current practices and policies in the host country, including for instance the national position vis-à-vis nuclear energy. Plausible alternatives scenarios for a newly built pulverised coal power plant with CCS may for instance include the following:

- The project activity without CDM.
- A new pulverised coal plant, but without CCS.
- A coal gasifier.
- A coal gasifier with CCS.
- A gas-fired power plant.
- A gas-fired power plant with CCS.
- A new pulverised coal plant with useful application of CO_2 in horticulture, or in the food & beverages industry[3].
- Import of electricity from poorly or unconnected grids by means of new interconnections.

The alternatives have to provide the same service level as the project activity in order to evaluate additionality. Not only must the load factor of the alternative activity be similar, in order not to reduce base of peak load capacity in the host country, also the size of the alternative activity has to be the same. We suggest that for the project power plant with CCS the alternative would be either:

a) The construction of a smaller power plant that provides the same quantity of net electricity.
b) The construction of the same size of power plant and feeding the remainder of the electricity in the grid thereby displacing grid electricity.

The tools for demonstration of additionality introduced in Section 2.1.1 stipulate that each of the identified baseline scenarios must be consistent with 'mandatory laws and regulations', which may help to reduce the number of alternatives.

Both additionality tools suggest to use either an investment analysis, to assess which alternative scenarios is the most economically or financially attractive, or a barrier analysis. In a barrier analysis, barriers must be identified that prevent the implementation of the project activity in absence of the project being registered under the CDM. These may include for instance lack of access to capital, or information or behavioural barriers. In addition, the barrier analysis also considers whether or not the alternatives would be hampered by such barriers.

However, for CCS operations it will be difficult to provide convincing evidence of (non-financial) barriers, such as technological or information barriers, considering the involvement of oftentimes large industries. Also, a barrier analysis may be subjective and lack transparency. Therefore, we recommend that for CCS in power and natural gas processing plants under the CDM an investment comparison analysis is the most appropriate for the demonstration of additionality, and that additionality may not be demonstrated by a barrier analysis only. A barrier analysis could be used to support the findings of the investment analysis.

In the investment analysis various financial indicators may be used to demonstrate additionality, including the net present value or internal rate of return of an investment, or the cost of electric-

[3] Producing food grade CO_2 may be a realistic baseline scenario in a number of cases. It may be produced by amine technology, as in regular post-combustion capture. Sometimes an additional purification step may be necessary. The economies of scale of such a process will be limited, because the global market for food grade CO_2 is about 8 Mton/yr. Still, the additional costs will not be excessive. Food grade CO_2 has 99.99% purity, and apart from the amine solvents carbon filters and molecular sieves are needed to achieve this (IEA, 2003). Most likely, the costs of such treatment will not be larger than on the order of tens of percents. Associated cost of food grade CO_2 production are in the US were reported to be generally in the region of US$100/tonne (IEA, 2003).

ity. We suggest that for CCS projects the cost for generating electricity could be used as a suitable financial indicator, and calculated precisely for each of the alternative baseline scenarios. The electricity generation cost for distinct power generation technologies provided by IPCC (2005) illustrate clearly that generation costs are in ranges (see Table 2.1), and that more specific and local data need to be used to make a fair investment comparison. It should also be noted that the costs of CCS are subject to changes; in recent years, estimates of CCS costs have risen considerably and the cost reported by the IPCC can be regarded as outdated.

Table 2.1 *Production costs for electricity for different types of generation, with and without CO_2 capture and storage*

Power plant system	Generation cost [USct_{2002}$/kWh]
Pulverised coal with CCS	6-10
Pulverised coal without CCS	4-5
IGCC without CCS	4-6
IGCC with CCS	5-9
NGCC without CCS	3-5
NGCC with CCS	4-8

Source: IPCC, 2005.

2.3 What emission sources should be included in the project boundary?

The project boundary of a CDM project refers to all (potential) emission sources in the baseline and project scenarios that need to be monitored and reported. The spatial extent of the CDM project boundary with CCS includes the power plant, the capture installation, the transport facilities, and the storage complex, including both the reservoir and the surrounding geological domains. For natural gas processing the separation plant may be excluded as CO_2 separation takes place both in the baseline and project scenario. All equipment that is additional to the baseline scenario, e.g. CO_2 compression, should be included.

Emissions from a full CCS chain within such project boundaries would comprise:

a) The project power plant and capture installation:
   - the combustion installation.
b) Emissions during transport of the CO_2:
   - compression installations along the CO_2 pipeline,
   - fugitive emissions along the CO_2 pipeline.
c) Emissions during injection and storage:
   - combustion installations generating electricity for the injection of the CO_2,
   - fugitive and vented emissions at injection,
   - fugitive emissions from the storage complex (‘seepage’).

The greenhouse gases that should be included in the project emissions include carbon dioxide for all components of the project activity. Furthermore, we recommend that methane should be reported for storage in natural gas processing and coal bed methane operations, and for all components of the project activity. We consider emissions of nitrous oxide negligible.

Minimum standards need to be defined for the composition of the CO_2 capture stream from the project plant. This is because associated compounds in the CO_2 stream may affect pipelines and the geological storage reservoir. We recommend basing these standards on:

- The amended OSPAR Convention for the marine environment in the North East Atlantic.
- The 2006 amendment to the London Protocol (1996), which prohibits the dumping of waste offshore worldwide.

- The proposed EU Directive on the Geological Storage of CO_2.

Standards based on these documents would require a CO_2 stream to consist 'overwhelmingly' of CO_2, while 'concentrations of associated substances [would] be below levels that would adversely affect the integrity of the storage site and relevant transport infrastructure and pose a significant risk to the environment'. Alternative language may also be derived from applicable legislation in other regions, including the US and Australia.

2.4 How could baseline emissions be established?

Baseline methodologies must be chosen in accordance with decision 3/CMP.1 on 'Modalities and procedures for a clean development mechanism as defined in Article 12 of the Kyoto Protocol'. This decision states in article 48 that "in choosing a baseline methodology for a project activity, project participants shall select from among the following approaches the one deemed most appropriate for the project activity, taking into account any guidance by the Executive Board, and justify the appropriateness of their choice:

- Existing actual or historical emissions, as applicable, or
- Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment, or
- The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category."

In our elaboration of hypothetical methodologies (Part B of this report), distinct methodologies for retrofits and newly built power plants appeared necessary. Technical matters such as a change in load factor in retrofits can be dealt with more adequately in a separate methodology. Regarding the calculations of baseline emissions, we suggest to use the historical emissions as a baseline methodology (a) for retrofits in the power and non-power sectors, where the former operation is continued but the CO_2 is captured and stored. For new built operations the economically attractive course of action (b) would be better fit.

Baseline methodologies for natural gas processing differ from those for power plant installations in that distinct methodologies are not necessary for existing and new built operations. One single methodology could cover both types. In this single methodology (b) (economically attractive course of action) could be applied for both existing and new operations. In the identification of plausible alternative scenarios discontinuation of the operation (existing plants) or the absence of gas field operation (for new plants) should be included. This is an important requirement, as theoretically the situation could occur that the CER revenues from the project alone make the operation economical, rather than the revenues from natural gas sales[4]. In order to prevent this possible perverse incentive proper baseline scenario analysis is crucial.

In general, only methodologies that result in conservative estimates of emissions reductions are acceptable according the principles of the CDM, and the CDM Methodology Panel is more likely to evaluate these favourably. Conservative assumptions leading to high estimates of project emissions and low estimates of baseline emissions are therefore preferable.

For this conservativeness, we recommend to neglect baseline emissions from the reservoir. For natural gas processing installations, emissions from acid gas incineration in the baseline could also be neglected for this reason.

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[4] In many respects this is analogous to the destruction of HFC-23 from HCFC-22 plants, in which case a construction of a new plant could be financed completely by the expected CER revenues. In this specific case it has been decided that new HCFC-22 plants are not eligible under the CDM. It should be noted that for CCS operations this possible perverse incentive is likely to be substantially smaller, due to low global warming potential of CO_2 compared to HFC-23. This will be analysed further in an upcoming report.

2.5 How may site integrity and permanence of the CO_2 storage be dealt with?

The novelty of the technology and the relative lack of practical experience have given rise to concerns regarding site integrity and permanency of the CO_2 storage. Concerns with permanency are partly related to the fact that the CO_2 would need to be stored over geological timeframes for which human experience to date is considered rather poor (e.g. storage of nuclear waste). It turned out difficult to address those concerns in the demonstration of additionality or in the calculation of emission reductions of any of the hypothetical projects.

Instead, we suggest dealing with good site characterisation and site selection, monitoring, site development and liability in the following ways:

1) In a decision by the COP/MOP which would exclude all CCS operations from the CDM for which good site characterisation and site selection, monitoring, site development and/or liability cannot be guaranteed. Such a decision could stipulate that detailed criteria in this respect could be part of the general applicability conditions of a baseline methodology, which would need to be scrutinised by a dedicated panel of experts (see Section 3).
2) In the general applicability conditions of a baseline methodology. As an example, three annexes have been attached to each of the CDM methodologies included in part B this report:
   - Annex A: Generic requirements for site selection, monitoring, site development and liability.
   - Annex B: Criteria for the characterisation and assessment of storage sites.
   - Annex C: Criteria for establishing and updating the monitoring plan for the storage complex and injection facilities.

The wording in each of these annexes is based on language in the proposed EU Directive on the Geological Storage of CO_2 (reference), and is likely to be subject to modifications based on regulatory frameworks developed in other parts of the world.

The requirements referred to in a COP/MOP decision and in more detail in the applicability conditions reflect an assessment of the procedures followed so as to ensure zero leakage. Compliance with these procedures would then need to be verified prior to authorisation of the project by the CDM Executive Board (see Section 3). Such a process-based assessment of site characterisation will allow the CDM EB and/or the host country to gain more experience with the selection of storage reservoirs in a wide range of geological settings.

2.6 How could the energy penalty be accounted for?

Capturing the CO_2 from power plants or industrial energy requires additional energy. For pulverised coal power plants, this energy penalty is on the order of 24-40% (IPCC, 2005). This will lead to additional emissions, not only from the combustion of the extra fuel, but also because this will imply an increase in emissions upstream of the project activity. These emissions can be substantial (see e.g. Viebahn et al., 2007).

We recommend distinguishing between the way emissions from the additional fuel combustion are accounted for in newly built power plants and retrofits.

In newly built power plants, we suggest to assume in the baseline that electricity produced is equal to the gross electricity generated by the power plant in the baseline. Note that in many cases this will be the project power plant without CCS, but it may also be a plant combusting another type of fossil fuel. As a conservative simplification, it could be assumed that for the part of the electricity used for capturing the CO_2 in the project plant, the higher emission factor is used among:

a) The baseline plant.
b) The build margin of the grid, i.e. total grid connected capacity.
c) The operating margin of the grid, i.e. the power plants listed in the top of the grid dispatch order.

This approach is similar to the approach in ACM0013[5] or in the 'Tool to calculate project, baseline and/or leakage emissions from electricity consumption'. This conservative assumption appeared satisfactory to the CDM Methodological Panel in its decisions on ACM0013 and named tool.

For retrofit power plants, we suggest to assume that the electricity lost will be compensated by extra electricity acquired from the grid and allow this electricity generation as part of the project boundary. For non-power sectors, we have also included part of the acquired grid electricity, or on-site generation in the project boundary. The latest Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion can be used.

As for the upstream emissions of the energy penalty, we recommend using IPCC emission factors for fugitive methane emissions during coal mining. This was also the approach followed in AM0029[6] and is sensible way forward, since these emission factors have a sound scientific basis. In order to calculate the amount of coal that needs to be combusted for capturing the CO_2, the operational efficiency of the power plant needs to be known. For the newly built power plant this efficiency would be chosen conservatively as the lower value between a default efficiency, for instance as specified by the manufacturer of the plant equipment, and a benchmark efficiency, which would represent best practice. For the retrofit plant, the operational efficiency of the project plant with CO_2 capture at average load would be used.

Upstream emissions from the energy penalty will not be accounted for under the EU ETS. This may cause some policy friction, because it would give CCS operations in non-Annex I countries a disadvantage over operations in the EU. Neglecting upstream fugitive emissions however would not be in line with the emission reduction accounting system of the CDM and may well render the inclusion of CDM in the CCS even less acceptable to opponents. We therefore recommend including them.

2.7 How may changes in the load factor of retrofit plants be addressed?

Another important issue for retrofit power plants is the impact that CCS may have on the position of the plant in the merit order dispatch. As a result of the implementation of CCS in the CDM project activity, the plant may run differently than it would have in the baseline. Exactly how remains to be seen, and arguments exist for both an increase and a decrease of the load factor in a power plant following the implementation of CCS technology.

Capturing CO_2 will lead to an increase in the short run costs of the plant. However, CCS operations under the CDM however will benefit from CERs, and part or all of these CERs may be used to offset the short run costs of a CCS operation. In that case there would be no need to push the power plant further down the merit order and thus reduce the load factor. In addition, implementation of CO_2 capture and storage technology would complicate any discontinuation of the power plant, since this would require a stop of transport and injection as well. Frequent discontinuations of the CO_2 flow may undermine the justification for capital investment in the transport and storage operations ,

5 Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology.
6 Methodology for grid connected electricity generation plants using natural gas.

In view of the potential CER revenues and preference for continuous operations, we would suggest to assume that the position of the power plant in the merit order will be higher (i.e. lower short-run cost compared to the baseline) rather than lower. The load factor thus may increase following the implementation of the project activity. This will favour the efficiency of the power plant and lower on average the emission factor of the plant, in terms of tCO_2/MWh.

A higher load factor of the project plant would have two effects. Firstly, electricity production by the plant would increase, thus replacing part of the electricity previously supplied by the grid. The assumption implies that part of the electricity supplied by the grid prior to the project activity should be accounted for in baseline emissions. The contribution of this grid electricity to baseline emissions may be estimated as the increase in electricity production in the power plant, equal to the difference between the historical average electricity production, and current production during the project activity. Then one needs to use the lowest value among the emission factors from:
a) the power plant prior to the project activity,
b) the built margin of the grid,
c) the operating margin of the grid.

Even in if electricity production in the project plants helps to cover demand growth, if would replace grid electricity. This is because in absence of the project power plant, the electricity grid would supply the electricity needed to cover demand growth.

Secondly, the increased load factor may imply that the CO_2 produced per MWh in the power plant in the project activity is lower than before, because the plant runs more efficiently. So, while the capture and storage of CO_2 will lead to a reduction of the emission factor, the amount of CO_2 reduced may be less than expected due to a higher plant efficiency. Therefore, we suggest that the emission factor of the project power plant is estimated conservatively as the lowest value between
a) the historical emission factor from the power plant,
b) the emission factor from the project plant without the CCS component.

2.8 How to deal with uncertainties in the quantification of seepage from the reservoir and fugitive emissions during the crediting period?

If a storage site were to leak unexpectedly during the crediting period, the operator would need to surrender CERs to the CDM Executive Board for any emissions to the atmosphere or the marine environment. This implies that any seepage would need to be quantified.

Identification of seepage is regulated in the proposed EU Directive on the Geological Storage of CO_2, and a host of monitoring tools are available to identify seepage. However, quantifying the emissions from seepage is more difficult. In situ quantification measurements in case of a leak may have uncertainties on the order of 20% (Benson, 2006). This uncertainty needs to be addressed in order to avoid the underestimation of emissions and to ensure the greenhouse gas integrity of the CDM.

As a conservative approach we recommend that estimated emissions from seepage are amplified with an 'uncertainty supplement'. This supplement is equal to the level of uncertainty which is associated with the quantification approach used for the leakage in question, for instance at a confidence level of 95%. This is the approach taken in the proposed Monitoring and Reporting Guidelines (MRGs) for CCS operations under the EU Emissions Trading Scheme that are currently being developed. These are considered conservative and aim to guarantee the greenhouse gas integrity of the EU ETS.

Fugitive emissions from pipelines may be estimated in a mass balance approach. This is done conservatively by correcting all measurements for the measurement uncertainty at e.g. the 95% confidence level. This approach may turn out to be overly conservative, because emissions leaking from the pipeline network may be up to orders of magnitude smaller than the measurement uncertainty. Therefore, we suggest that the project proponents set up a measurement campaign to estimate an emission factor for the transport network. Such an emission factor would need to be verified by an accredited DOE and approved by the CDM EB. Once such a pipeline emission factor has been established fugitive emissions may be estimated using either the mass-balance approach or the emission factor approach, whichever provides the highest emission estimate. The EU MRGs under development referred to above also include such a twin track approach to estimating fugitive pipeline emissions.

2.9 How may the increased availability of fossil fuels from enhanced hydrocarbon recovery be accounted for?

A critical concern expressed by opponents of CCS in the CDM, e.g. at COP/MOP3 in Bali, is the increased production of fossil fuel, and associated emissions, in enhanced hydrocarbon operations, including Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhance Coal bed Methane Recovery (ECBM).

If enhanced hydrocarbon recovery is included in the CDM in spite of these concerns, we can see two ways to approach this issue in a baseline methodology for CCS.

a) It is assumed that in absence of the enhanced hydrocarbon operation, the additional oil or gas production would be obtained from other operations. In this case, no increase in global fossil fuel consumption is anticipated and concerns with respect to such an increase are ignored.[7]
b) The point of departure is that the additional oil or gas production will be actually used on top of what would be consumed in a baseline scenario, which would imply that global fossil fuel consumption increases.[8]

One could argue not to account for emissions from increased fossil fuel consumption (i.e. the first option, above). In fact, the increase of extracted fossil resources is considered insignificant in the EU. The reason is that demand effects are likely to be small, and that it is very difficult to quantify the increase in oil and gas production. Moreover, a similar rebound effect impacts on energy efficiency projects: any reduction in oil and gas demand will reduce fossil fuel prices and thus result in an increase in energy consumption. Still, opponents will argue that such rebound effects in energy efficiency projects will need to be quantified as well, and that they can be no excuse to allow for an increase in fossil fuel production through EHR operations. They would prefer the second and more conservative approach.

We anticipate that resolving this issue will be extremely difficult. In general, international acceptance of CCS in the CDM may be increased if enhanced hydrocarbon recovery operations were excluded. We recommend not to pursue inclusion of such operations, and to focus political efforts on other options for the geological storage of CO_2.

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7 Note that this is the approach reflected in the proposed EU Directive on the Geological Storage of CO_2.
8 Note that this argument works slightly differently for natural gas produced in EGR and ECBM operations. An increased production of natural gas may well reduce the carbon intensity of the economy and lead to lower emissions. Thus, neglecting this effect may well be considered a conservative assumption.

2.10 How to deal with any seepage from the reservoir after the crediting period?

Long term seepage is one of the most persistent issues in the debate on CCS in the CDM. The liability of any CO_2 leaking back to the atmosphere after the site has been closed needs to be resolved to ensure the greenhouse gas integrity of the CDM. However, private parties generally are too short-lived to take on any long term liability for seepage, and would prefer to hand this over to the national authority at some point.

During the crediting period, any seepage should be detected by proper implementation of the monitoring plan, as included in the PDD. In case of seepage during the crediting period and while the operator is still liable, the operator would need to surrender equivalent amounts of CERs. It can be assumed that operators of CO_2 storage operations will want to close down a storage site after the crediting period, because in absence of the revenues from CERs the operation will no longer be profitable[9]. Note that if CCS is included in the CDM, there may be a need to reconsider the length of the crediting period, to make sure that investors in this costly technology benefit for a longer period of time of CERs obtained for avoided CO_2.

The procedure for liability transfer could be laid down in a COP/MOP decision. We recommend that after site closure, the operator remains responsible for maintenance, monitoring, control, reporting, and corrective measures. The post-closure requirements would be fulfilled on the basis of a provisional post-closure plan submitted to and approved by either the CDM EB or the host country (see Section 3). Once good site performance and zero leakage for the indefinite future have been demonstrated, liability for the site would be handed over to the competent authority in the host country. Alternatively, liability is handed over after a fixed period of time e.g. 30, 50 or 100 years, in line with host country laws. While the latter seems more transparent, it might in certain cases lead to a reduction of the monitoring effort once injection has ceased, because the decision of closing the site would not longer depend on the monitoring results. The debate on this may be informed by the discussions of the proposed EU Storage Directive in respect of liability transfer.

It follows that after site closure and handover of liability to the competent authority in the host country, the site may no longer be monitored, since most host countries will be reluctant to spend resources on this. We have identified three alternative approaches to address any concerns on long term seepage from the reservoir.

a. Continued monitoring of any CCS operation after the crediting period would be considered a prerequisite for inclusion of CCS in the CDM. This implies that financial means would need to be made available from the operator (or via Annex 2 countries) to enable the host country to continue monitoring and to take any corrective measures if needed after it takes on liability for the site. This could be realised for instance by taxing the CERs obtained in the project.
b. Continued monitoring of the CCS operation after the crediting period were not considered important, because site integrity and long term permanence of the CO_2 have been demonstrated satisfactorily. Should any seepage of CO_2 by coincidence be detected, for instance by coincidental visual detection or major ecosystem mortality, then two options exist to approach this:
   - Any seepage would be considered negligible compared to the cumulative amount of CO_2 that may be stored in CCS operations under the CDM worldwide. In other words, the risk of seepage (and the implications for health, the local environment and the global climate) is accepted and consciously ignored.
   - Corrective measures would need to be taken by the host country. In this case, a financial transfer from the operator to the state may be needed to enable host countries to take the

[9] This could be different however in the case the project takes place in a country that has mandatory regulation with regard to GHG emissions at the end of the crediting period.

corrective measures required, and to resume monitoring of the site. Again, a tax levied on CERs would be an alternative way to pay for this.

It will be up to the Parties in the international negotiations on the inclusion of CCS in the CDM to resolve this difficult issue.

3. Institutional implications for safe CCS operations in the CDM

While well-considered methodologies for CCS operations would be imperative for preserving the environmental integrity of the CDM, a number of institutional arrangements may be required as well. These will be needed to check compliance with requirements on site characterisation and selection, monitoring and liability, as could be laid down in a COP/MOP decision or in more detailed applicability conditions for CCS baseline methodologies (see Section 2.5). We suggest the following institutional structure for guaranteeing that CCS is implemented safely and permanently.

The requirements additional to normal CDM requirements apply to the legislative framework in the host country. The applicability conditions require that the host country has legislation in place to permit CCS operations in a responsible manner and deal with site selection, monitoring, site development and liability. This would imply the following steps in project approval:

- The competent authority for CCS permitting drafts a decision on a storage permit for the CCS operation, in which site integrity and storage permanence are duly dealt with.
- The DNA includes the draft decision of the competent authority in its Letter of Approval on the CCS project as a CDM activity.
- A dedicated CCS accreditation would be required for DOEs validating and verifying CCS operations under the CDM. The DOE should have demonstrable experience with CCS. It would validate and verify according to the normal procedures for CDM projects.
- A CCS panel under the CDM EB consisting of geological, technical and legal experts considers whether the host country indeed has an effective legislative framework in place, and thus whether the requirements are met This would need to happen only once before the project registration. From then on, the CDM EB considers the host country legislation adequate and only the technical details of each new project submitted for registration are reviewed. The CDM EB approves or rejects the request for registration of the CCS-CDM project.
- When the project is up and running, the project developer requests for issuance of the CERs. For this, the accredited DOE verifies the emission reductions. The CCS Panel opinion on this will guide the CDM EB in this decision, apart from the usual considerations on the credits generated by the CDM project.

This procedure would rule out any CDM projects in candidate host countries that do not manage to regulate the risks of CCS operations on their territories in a timely fashion. It would avoid the need of an international regulatory regime for CCS, but would imply UN involvement in domestic policies and regulations, which may be perceived negatively. It is schematically illustrated in the figure below.

Alternative arrangements are conceivable as well. For instance, one might argue dedicated CCS accreditation would make an special CCS panel redundant, since both would review technical issues of the CCS operation. Also, the process of evaluating the adequacy of the CCS legislative framework may be done at a higher and more independent level than by a panel under the CDM EB and before the stage of a project or methodology approval.

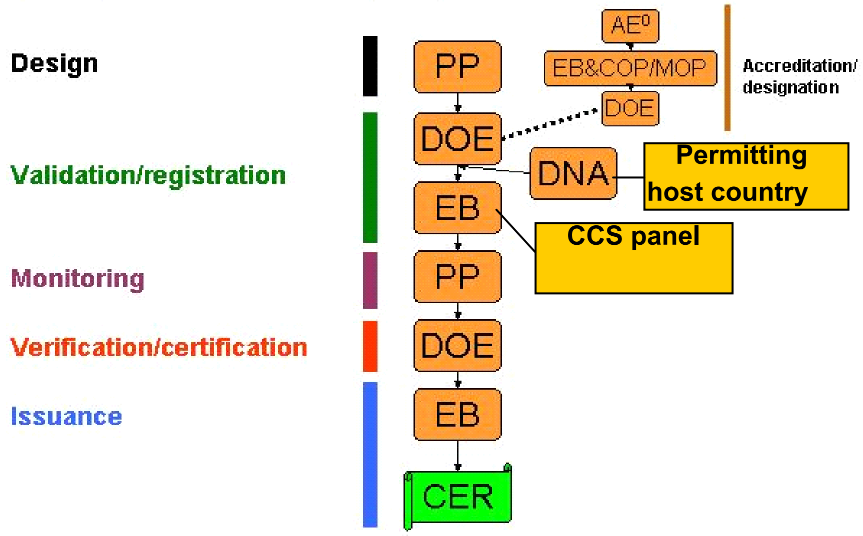

Figure 3.1 *Suggested adjusted CDM project activity cycle for a proposed CCS operation under the CDM*

Note: The permitting authority will have to license the project before the DNA does, and the CCS panel provides advice to the EB on the approval of the project, and on the issuance of the credits.

The institutional framework for responsible CCS inclusion in the CDM would necessitate the development of regulatory frameworks for CCS in non-Annex I countries. In major industrialised regions, notably the EU, the US and Australia this has turned out to be time-consuming and to require substantial input from experts in research and industry. While some developing countries may have the resources to develop such a framework themselves, many countries may prefer to spend their resources on higher priority policy issues. It is therefore recommended that Annex-I countries make available funds to help developing countries develop the legal framework to implement CCS safely.

The requirement of national CCS frameworks might slow down the implementation of CCS operations in non-Annex I countries. If such legal frameworks need to be developed, this is likely to take several years, and the operation of the new legislative framework may also be time-consuming. Yet, it would allow developing countries that display an interest in CDM projects with CCS technologies to push ahead the option by elaborating their own legislations. In the initial phases, it could even be considered to combine learning on technology and learning on legislation.

The CCS panel would have the following tasks and responsibilities:

- Check the relevant national laws and regulations against the Letter of Approval provided by the DNA, and whether this national legislation adequately deals with site selection and monitoring, remediation, well abandonment and long term liability.
- Develop a CCS-specific PDD model. Such a template would leave room for CCS-specific aspects and allow for more consistency in PDDs for CCS projects.
- Evaluate for any proposed CCS project and the DOE validation report under the CDM:
  - The contingency plan.
  - The well abandonment plan.
  - The post-closure plan, referred to in Annex A of the applicability conditions.
  - Site characterisation and selection, based on the criteria referred to in Annex B of the applicability conditions.
  - The specific geological aspects of the monitoring plan for the storage complex and injection facilities, based on the criteria referred to in Annex C of the applicability conditions.

- Provide CDM EB with a recommendation on the baseline methodology and the PDD of the CCS project based on the safety and permanence of the CO_2 storage.
- Review the DOE verification report.

4. Conclusions and recommendations

In Part A we have discussed ways to enable CO_2 capture and storage under the CDM. We found that many of the concerns in respect of the inclusion of CCS and the CDM can be met by elaborating well-considered and conservative baseline methodologies. Exceptions are the issues of site integrity and permanence of the CO_2 storage, and long term liability. We recommend that these issues are dealt with in a COP/MOP decision that would exclude all CCS operations from the CDM for which good site characterisation and site selection, monitoring, site development and/or long-term liability cannot be guaranteed.

On top of that, *site integrity and permanence* could be ensured by making the applicability of any CDM methodology for CCS contingent on compliance with more detailed requirements for site selection, monitoring and site development. In that case institutional arrangements would be needed as well, notably the establishment of a CCS expert panel. This CCS panel would check compliance with aforementioned requirements. This could be done by a evaluating of all candidate CCS projects under the CDM, and verifying that requirements are met by the project participant prior to authorisation of the project by the CDM EB. This may require international consensus on mostly technical criteria to evaluate CCS projects. Therefore, we recommend instead an assessment by the CCS panel of the legislative framework in the host country for permitting CCS operations. This would prevent a political deadlock caused by cumbersome discussions on technical issues. Either way, clearly defined responsibilities and authority of the CCS panel would need to be ensured, as well as special accreditation for DOEs verifying CCS operations under the CDM. Maybe a note that a new project scope for CCS would need to be included.

Long term liability for seepage may be the most challenging issue to tackle if CCS is to be included in the CDM, and we suggest a separate decision by the COP/MOP on this matter. We recommend that after closure the operator would continue monitoring and remain liable for any seepage occurring. However, the operator should be able to hand over liability once it has been demonstrated that the storage site performs satisfactorily and that no seepage needs to be anticipated. Alternatively, liability is handed over after a fixed period, e.g. 30, 50 or 100 years. Either way, we recommend ensuring that financial provisions are made for any monitoring or corrective measures for unexpected seepage by the host country that would be considered necessary.

Apart from these issues, most concerns vis-à-vis CCS in the CDM can dealt with in baseline methodologies, as follows.

- For *demonstration of the additionality* of CCS projects under the CDM, adequate tools are available that have been approved by the CDM Methodological panel. It is recommended that in the identification of plausible alternative scenarios, consideration is also given to the fate of the CO_2 and the condition of the geological reservoir in absence of the project activity. In addition, a mandatory investment analysis is proposed to provide unambiguous evidence on the additionality of the project.
- Emission sources within the *project boundary* include both fugitive and combustion emissions along the CCS chain, as well as reservoir seepage. This concerns mostly carbon dioxide, but for natural gas processing operations and storage in ECBM operations methane emissions should be reported as well.
- *Baseline emissions* for retrofit power plant are best based on historical emissions, whereas for new built power plants and for all natural gas processing operations the economically most attractive course of action needs to be the starting point. In order to advance conservativeness of the methodologies, it is recommended to disregard baseline emissions from the reservoir and from acid gas incineration, which are difficult to estimate. Ignoring these will lead to a lower estimate of reduced emissions.

- Emissions related to the *energy penalty* required for capturing the CO_2 may be accounted for without difficulty in the calculation of baseline emissions. For newly built power plants, baseline emissions for the electricity used in the project to capture CO_2 should based on the higher emissions factor among either the baseline plant, the built margin or the operating margin of the grid. For retrofit plants, electricity required for capture will most likely be compensated for by the grid, and this should be included in the project boundary. Fugitive emissions upstream related to the energy penalty may be accounted for as leakage.
- It can be argued that retrofitting existing power plants with CCS is likely to increase the *load factor* of the plant. This implies that the project plant would replace part of the electricity supplied previously by the grid. This electricity should be accounted for in baseline emissions, using a conservative emission factor. In addition, the emission factor for the electricity from the power plant itself will be affected by the retrofit, and should be estimated conservatively as well.
- For reasons of conservativeness it is recommended that *seepage* from the reservoir during the crediting period is adjusted by an uncertainty supplement, and likewise to correct any fugitive emissions along the CCS chain for measurement uncertainty.

5. References

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6. List of abbreviations

A(C)M	Approved (Consolidated) baseline and monitoring Methodology
ACM000X	Approved Consolidated CDM Methodology no. X
CCS	CO_2 capture and geological storage
CDM	Clean Development Mechanism
CDM EB	CDM Executive Board
CER	Certified Emission Reduction
CMP/COPMOP	Conference Of the Parties to the UNFCCC serving as the Meeting Of the Parties to the Kyoto Protocol
COP	Conference of the Parties to the UNFCCC
DNA	Designated National Authority
DOE	Designated Operational Entity
ECBM	Enhanced Coal Bed Methane
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
GHG	Greenhouse gas
MRG	Monitoring and Reporting Guidelines
OSPAR	OSPAR (stands for *Oslo and Paris*) Convention, combined 1972 Oslo and 1974 Paris Conventions
PDD	Project Design Document
PP	Project proponents
SBSTA	Subsidiary Body for Scientific and Technological Assistance
UNFCCC	United Nations Framework Convention on Climate Change

Part B: Illustrative baseline methodologies

Contents

Appendix I Illustrative CDM baseline methodology for capture of CO_2 from an existing coal-fired power plant and its use in a newly developed enhanced coal bed methane recovery

CLEAN DEVELOPMENT MECHANISM
PROPOSED NEW BASELINE AND MONITORING METHODOLOGIES
(CDM-NM)
(Version 03.1)

CONTENTS

Section B. Summary and applicability of the baseline and monitoring methodology

1. Methodology title (for baseline and monitoring), submission date and version number
Capture of CO_2 from an existing coal-fired power plant and its use in a newly developed enhanced coal bed methane recovery operation.

2. If this methodology is based on a previous submission or an approved methodology, please state the reference numbers (NMXXXX/AMXXXX/ACMXXXX) here. Explain briefly the main differences and their rationale.

ACM0007: From this methodology, the CH_4 leakage is derived from a consolidated methodology for "conversion from single cycle to combined cycle power generation"

3. Summary description of the methodology, including major baseline and monitoring methodological steps

Section C. Proposed new baseline and monitoring methodology

Draft baseline and monitoring methodology AMXXXX

"Capture of CO_2 from an existing coal-fired power plant and its storage in an ECBM operation"

I. SOURCE, DEFINITIONS AND APPLICABILITY

Sources

This consolidated baseline and monitoring methodology is based on [elements from] the following [approved baseline and monitoring methodologies and] proposed new methodologies:

- ACM0007 (version 3): "Baseline methodology for conversion from single cycle to combined cycle power generation"
- AM0064 (version 01.1): "Methodology for mine methane capture and utilisation or destruction in underground, hard rock, precious and base metal mines"

This methodology also refers to the latest approved versions of the following tools (please delete those not applicable):

- Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion;
- Tool to calculate project emissions from electricity consumption;
- Combined tool to identify the baseline scenario and demonstrate additionality

For more information regarding the proposed new methodologies and the tools as well as their consideration by the Executive Board please refer to http://cdm.unfccc.int/goto/MPappmeth.

Selected approach from paragraph 48 of the CDM modalities and procedures

This new methodology uses "Existing actual or historical emissions, as applicable (48a)".

Definitions: Please provide definitions of key terms that are used in this proposed new methodology

1. For the purpose of this methodology, the following definitions apply:

- **Geological storage of CO_2** means injection into and storage of CO_2 streams in underground geological formations;
- **Storage site** means a specific geological formation used for the geological storage of CO_2;
- **Geological formation** means a lithostratigraphical subdivision within which distinct rock layers can be found and mapped;
- **Seepage** means any release of CO_2 from the storage complex;

- **Storage complex** means the storage site and surrounding geological domains which can have an effect on overall storage integrity and security (*i.e.*, secondary containment formations);
- **Exploration** means assessing potential storage complexes by means of a specific procedure including activities such as carrying out geological surveys by physical or chemical means and drilling to obtain geological information about strata in the potential storage complex;
- **Operator** means any natural or legal, private or public person who operates or controls the storage site or to whom decisive economic power over the technical functioning of the storage site has been delegated according to national legislation; This person may change from the storage preparations to the post-closure phase;
- **Substantial change** means a change which may have significant effects on the environment;
- **CO_2 stream** means a flow of substances that results from carbon dioxide capture processes;
- **CO_2 plume** means the dispersing volume of CO_2 in the geological formation;
- **Migration** means the movement of CO_2 within the storage complex;
- **Significant irregularity** means any irregularity in the injection or storage operations or in the condition of the site itself, which implies the risk of a leakage;
- **Corrective measures** means any measures taken to correct significant irregularities or to close leakages in order to prevent or minimise the release of CO_2 from the storage complex;
- **Closure of a CO_2 storage site** means the definite cessation of CO_2 injection into that storage site;
- **Post-closure** means the period after the closure of a storage site, including the period after the transfer of responsibility to the competent authority;
- **Transport network** means the network of pipelines, including associated booster stations, for the transport of CO_2 to the storage site.
- **Enhanced coal-bed methane (ECBM)** is the use of CO_2 to enhance the recovery of the methane present in unminable coal beds through the preferential adsorption of CO_2 on coal.
- **Saline formation** means a sediment or rock body containing brackish water or brine.
- **Retrofit**: A modification of the existing equipment to upgrade and incorporate changes after installation.

Applicability conditions

1. This methodology applies to project activities that capture CO_2 from existing coal-fired power plants, transport it, and store it in an Enhanced Coal Bed Methane recovery operation. CO_2 capture and storage is a multi-component option for reducing greenhouse gas emissions. Emissions are not reduced unless all components are fully executed. A combination of applicability conditions is therefore necessary. Given the technical specifics of both retrofit CO_2 capture on coal-fired power plants and storage of the CO_2 in an Enhanced Coal Bed Methane recovery (ECBM) operation, it is appropriate to set up a specific methodology for the combination of these components only. The baseline would also change considerably if the ECBM operation would already be ongoing.

2. The methodology is applicable under the following conditions:
   - The generic requirements for site selection, monitoring, site development and liability (Annex A) are met, regardless of any legal framework for CCS operations that host country may or may not have in place.
   - The power plant is not a cogeneration plant;
   - The CO_2 stream transported by pipeline to the storage location shall consist overwhelmingly of carbon dioxide. To this end, no waste and other matter may be added for the purpose of disposing of that waste or other matter. However, a CO_2 stream may contain incidental associated substances from the source, capture or injection

process. Concentrations of those substances shall be below levels that would adversely affect the integrity of the storage site and relevant transport infrastructure and pose a significant risk to the environment.

- Capture of CO_2 from one already operational coal-fired power plant that does not co fire any biomass
- Injection the CO_2 in its supercritical or liquefied form, with no intention of ever recovering it, in an unminable coal bed that currently is not operated to produce methane, and
- Full recovery and use of the methane produced by the coal bed and utilisation to produce electricity, motive power and/or thermal energy and/or destroyed through flaring
- Appropriate site development in accordance with Annex A.
- Appropriate site characterization and selection in accordance with Annexes A and B.
- An appropriate monitoring plan in accordance with Annexes A and C.

In addition, the applicability conditions included in the tools referred to above apply.

3. The methodology does not apply when:
   - The coal-fired power plant co-fires biomass
   - The methane produced is vented to the atmosphere
   - The power plant's capacity is upgraded to accommodate the energy penalty

4. Finally, this methodology is only applicable if the application of the procedure to identify the baseline scenario results in that continuation of the initial power plant operation is the most plausible baseline scenario.

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

The spatial extent of the project boundary includes the coal-fired power plant, the capture installation, the transport facilities, the entire storage complex that is used for the ECBM operation, and the soil above the coal bed.

Project emissions include emissions from:
a) the project power plant and capture installation:
b) emissions during transport of the CO_2:
- compression installations along the CO_2 pipeline
- fugitive emissions along the CO_2 pipeline

c) emissions during injections and storage:
- combustion installations generating electricity for the injection of the CO_2
- fugitive emissions at injection
- fugitive methane emissions from the coal bed

5. The greenhouse gases included in or excluded from the project boundary are shown in Table 2.

Table 2: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Coal-fired power plant	CO_2	Yes	Main emission source. The baseline being the operation of the power plant without CO_2 capture and storage, the existing emissions of CO_2 need to be established
	Coal bed	CO_2	No	Given the depth of injection and the affinity of the coal with CO_2, it is not considered likely CO_2 injected will escape to the atmosphere. Hence, there is also no need for baseline data.
		CH_4	Yes	Baseline methane emissions need to be established
Project Activity	Coal-fired power plant with capture	CO_2	Yes	CO_2 produced by the power plant that is not captured should be taken into account, as well as CO_2 resulting from energy use in the capture process.
	Pipeline	CO_2	Yes	Potential pipeline seepage and emissions from booster installations along the pipeline
	Coal bed	CO_2	Yes	This includes emissions from the combustion of fossil fuels required to run the injection, as well as fugitive and vented CO_2 emissions during injection.
		CH_4	Yes	Seepage of methane in the ECBM operation should be taken into account

Identification of the baseline scenario and demonstration of additionality

The combined tool to identify the baseline scenario and demonstrate additionality is used. This tool can be used as this methodology only applies to project activities that make modifications to an existing installation that is operated by project participants, as stipulated in the tool. Clarifications to the use of the various steps of the tool in this methodology are listed below.

Step 1: Identify plausible alternative scenarios

In substep 1 ('Define alternatives to the project activity') alternatives will be established for:

a. the way power would be generated in absence of the project activity
b. the fate of the CO_2 in absence of the project activity
c. the state of the coal bed in absence of the project activity.

Note that for many candidate project activities, plausible alternatives for power generation include at least the following:

a) The project activity without CDM
b) The project activity with CDM
c) Continued operation of the power plant without capture and use of CO_2 in an ECBM operation, combined with the ECBM operation with another source of CO_2
d) Continued operation of the power plant without capture and use of CO_2 in an ECBM operation, and no ECBM operation
e) Fuel switch of the power plant to gas
f) Fuel switch of the power plant to gas and capturing and use of the CO_2 in an ECBM operation

Step 2: Barrier analysis
The only eligible barrier for such project activities is the investment barrier. No other barrier shall be used to identify the baseline scenario and demonstrate additionality.

Step 3: Investment analysis
This step shall be implemented as described Step 3 of the latest version of the “Combined tool to identify
the baseline scenario and demonstrate additionality” approved by the Executive Board. The project shall identify which measures would be implemented even if there is investment barrier (i.e. without access to external capital). Any such measures shall be classified as non-additional. To substantiate this claim the project shall support this claim by providing access to official due diligence documentation (such as feasibility studies) sent to financial institutions which have been contacted for financing purposes.

Step 4: Common practice analysis
Since worldwide, there are no CCS projects that either capture most of the CO_2 from an existing coal-fired power plant, or use anthropogenic CO_2 for ECBM, this activity can safely be assumed to be not consistent with common practice. The IPCC (2005) notes that most of the components of CCS are not mature technologies.

Baseline emissions

The baseline emissions include the emissions of the power plant without capture and storage of the CO_2.
In addition, it is anticipated that in the project activity, the load factor of the plant will increase. This is because:
a) the revenues from CERs are likely to decrease short run costs, thus placing the power plant higher in the merit order dispatch;
b) discontinuation of the power plant is more difficult in the project activity than before, because it would necessitate interruption of CO_2 transport and storage as well, which would come at a cost and
c) a high load factor would make it easier to make up for the high capital requirement for CCS upfront.

Therefore, baseline emissions also comprise electricity that prior to the project activity was supplied by the grid, but that is supplied by the project power plant as the load factor increases during the project activity.

Thus, baseline emissions can be calculated as:

$$BE_y = BE_{PP,y} + BE_{grid,x}$$

Where:
$BE_{PP,y}$ = baseline emissions from the power plant (tCO_2)
$BE_{grid,y}$ = baseline emissions from the grid in year x (tCO_2)
x = the most recent year prior to the project activity for which data are available

Following option B in the “tool to calculate project or leakage emissions from fossil fuel combustion”, emissions of the power plant correspond to the emission factor (EF) (in tCO_2/MWh) in year *y* times the number of MWh produced in a year:

$$BE_{PP,y} = EF_{BL,y} * EG_{PC,net,y}$$

Where:

$EF_{BL,y}$	is the baseline emission factor in year *y* (tCO_2/MWh)
$EG_{PC,net,y}$	is the net electricity generated and supplied to the grid in year *y* (MWh)

The baseline emission factor in year *y* ($EF_{BL,y}$) will be chosen as the minimum value among the historical emission factor prior to the project activity, and the emission factor of the power plant in the reporting year. This is conservative, because the emission factor of the plant is likely to be affected by the change in load factor explained above. The baseline emission factor is therefore

$EF_{BL,y} = MIN(EF_x;EF_{PC,y})$

Where:

EF_x	=	emission factor of the power plant in year x (tCO2/MWh)
$EF_{PC,y}$	=	emission factor of the power plant with capture in reporting year y (tCO2/MWh)
x	=	the most recent year prior to the start of the project activity for which data are available

The first option is the emission factor of the power plant in year *x*, which is calculated as follows:

$$EF_x = \frac{FC_{BL,x} * NCV_{BL,x} * EF_{FF,BL,x}}{EG_{BL,x}}$$

Where:

$EG_{BL,x}$	=	the net electricity generated and delivered to the grid by the power plant in the year *x* (MWh)
$FC_{BL,x}$	=	the quantity of coal combusted in the power plant in year *x* (t)
$NCV_{BL,x}$	=	net calorific value of the coal combusted in year *x* (GJ/t)
$EF_{FF,BL,x}$	=	CO_2 emission factor of the fossil fuel type consumed by the power plant in year *x* (tCO_2/t)

The second option is the emission factor of the power plant with capture in the reporting year, calculated as:

$$EF_{PC,y} = \frac{FC_{PC,y} * NCV_{PC,y} * EF_{FF,PC,y}}{EG_{PC,net,y}}$$

Where:

$EF_{PC,y}$	=	emission factor of the power plant with capture in reporting year y (tCO2/MWh)
$FC_{PC,y}$	=	the quantity of coal combusted during year y (t)
$NCV_{PC,y}$	=	net calorific value of the coal combusted in year *x* (GJ/t)
$EF_{FF,PC,y}$	=	CO_2 emission factor of the fossil fuel type combusted in year *x* (tCO_2/t)
$EG_{PC,net,y}$	=	net electricity generated and supplied to the grid in year *y* (MWh)

Grid emissions in the baseline ($BE_{grid,x}$) arise from electricity production that is replaced by electricity from the project activity ($EG_{BL,LF,y}$) as a consequence of a higher load factor in the power plant, as explained above. They are calculated using the smallest among the emission factor from the power plant prior to the project activity, and the grid emission factor in the baseline based on either the built or the operating margin, as follows:

$BE_{grid,x} = EG_{BL,grid,,x} * MIN(EF_{BL,y},EF_{grid,BM,,x,},EF_{grid,OM,,x})$

$BE_{grid,x}$	=	Baseline emissions from the grid in year x (tCO2)
$EG_{BL,grid,x}$	=	Electricity supply from the grid in the baseline in year x, replaced by project

activity (MWh)

$EF_{grid,,BM,x}$ = Emission factor from the grid based on the built margin in year x (MWh)

$EF_{grid,OM,x}$ = Emission factor from the grid based on the operating margin in year x (MWh)

The grid emission factors $EF_{grid,,BM, x,}$ and $EF_{grid,,OM, x,}$ can be calculated using the "Tool to calculate the emission factor for an electricity system".
The additional electricity $EG_{BL,LF,y}$ produced by the project power plant as a consequence of its higher load factor equals:

$EG_{BL,grid,x} = EG_{PC,,net,y} - EG_{PP,avg}$

Where

$EG_{PC,,y}$ = Net electricity supply from the power plant with capture in reporting year y (MWh)

$EG_{PP,avg}$ = Average historical electricity supply from the power plant over the last 3 years prior to the project activity (MWh)

Project emissions

Project emissions include:
a) remaining emissions from the project power plant and capture installation:
b) emissions during transport of the CO_2:
- compression installations along the CO_2 pipeline
- fugitive emissions along the CO_2 pipeline

c) emissions during injections and storage:
- combustion installations generating electricity for the injection of the CO_2
- fugitive and vented emissions during injection
- fugitive methane emissions from the storage complex

Project emissions are estimated in the following steps:

Step 1: Calculation of the CO_2 emission of the power plant with capture ($PE_{PC,,y}$)

Step 2a: Emission from booster installations along the CO_2 pipeline (PE_{boo})

Step 2b: Emissions from any seepage from the transport infrastructure ($PE_{fug,T,y}$)

Step 3a: Fugitive and vented emissions during injection of the CO_2 ($PE_{fug,I,,y}$)

Step 3b: Emissions from combustion installations generating electricity for the injection of the CO_2 ($PE_{com,I,,y}$)

Step 3c: Emissions from any seepage from the storage complex ($PE_{res,y}$)

Applying these steps, the total project emissions are:

$$PE_y = PE_{PC,y} + PE_{boo,T,y} + PE_{fug,T,y} + PE_{fug,I,y} + PE_{com,I,y} + PE_{res,y}$$

Where:

PE_y are the project emissions in year y (tCO_2)

$PE_{PC,\ y}$ are the remaining project emissions from the power plant in year y (tCO_2)

$PE_{boo,T,y}$ are emissions from booster installations along the transport infrastructure (tCO_2)

$PE_{fugT,,y}$ are fugitive emissions from the transport infrastructure (tCO_2)

$PE_{fugI,,y}$ are fugitive and vented emissions during injection (tCO_2)

$PE_{com,I,y}$ are emissions from combustion installations generating electricity for the injection of the CO_2 (tCO_2)
$PE_{res,y}$ is seepage from the storage complex (tCO_2)

Step 1: Calculate the remaining emissions from the power plant with CO_2 capture.

Remaining CO_2 emissions from fossil fuel combustion in the project power plant with capture are calculated based on the combusted coal and the CO_2 stream fed into the pipeline network, as follows:

$$PE_{PC,y} = FC_{PC,y} * EF_{FF,PC,y} - Q_{in,y} * (1-U_{pipe,95})$$

Where:

$PE_{PC,,y}$	=	CO_2 emissions from fossil fuel combustion in power generation after capture during year y (tCO2/yr)
$FC_{PC,y}$	=	the quantity of coal combusted during year y (t)
$EF_{FF,pcC,y}$	=	CO_2 emission coefficient of the coal combusted in the project power plant in year *y* (tCO2/t)
$P_{in,y}$	=	measured CO_2 flow from the capture installation to the pipeline (t/yr)
$U_{pipe,95}$	=	measurement uncertainty at a 95% confidence level (-/-)

As a conservative assumption, the measured CO_2 flow from the capture installation to the pipeline is adjusted downward by correcting the measurement for the measurement uncertainty.

In line with the tool, the CO_2 emission coefficient $EF_{PC,y}$ can be calculated following two procedures, depending on the available data.

Option A: $EF_{PC,y}$ is calculated based on the chemical composition of the coal, as follows:

$EF_{FF,PC,y} = w_c * 44/12$

Where
w_C = weighted average mass fraction of carbon in the coal (tC/ t coal)

Option B: $EF_{PC,y}$ is calculated based on the net caloric value and CO_2 emission factor of the coal, as follows:

$EF_{,FF,PC,y} = NCV_{PC,y} * EF_{GJ,PC,y}$

Where
NCV_{PCy} = net caloric value of the coal combusted in the project power plant in year y (GJ/t)
$EF_{GJ,PC,y}$ = weighted average CO_2 emission factor of the coal combusted in the project power plant in year y (tCO2/GJ)

Step 2a: Emissions from booster installations along the CO_2 pipeline

Combustion emission from fuel use in booster installations shall be calculated in accordance with the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (version 01).

Step 2b: Emissions from any seepage in the transport infrastructure

Emissions from transport will be calculated using a mass balance approach. While continuous measurements of CO_2 flows are surrounded by a measurement uncertainty, a conservative estimate needs to be made. Therefore, measured values for the CO_2 mass flow into and out of the pipeline will be corrected as follows:

$$PE_T = Q_{in,y} * (1+U_{pipe,95}) - Q_{out,y} * (1-U_{pipe,95})$$

With
$PE_{T,y}$ = project fugitive emissions from pipeline transport [t/yr]
$Q_{in,y}$ = measured CO_2 flow from the capture installation to the pipeline [t/yr]
$Q_{out,y}$ = measured CO_2 flow out of pipeline to injection facility [t/yr]
$U_{pipe,95}$ = measurement uncertainty at a 95% confidence level [-/-]

Note: if mass balance leads to negative emissions, emissions will be assumed to be zero.

In the PDD the project developer shall elaborate a measurement campaign in order to estimate an emission factor for the pipeline network EF_{pipe} (tCO2/km/yr). Measurements will be conducted every year at representative locations of the transport network where leaks can be expected, e.g. at booster stations and pipeline joints. The emission factor shall be derived from the measurement results using statistical methods and taking into consideration the structure of the transport pipeline system, e.g. the number of booster stations, joints, etc. The development of the emission factor shall be documented and reported in detail, verified by an accredited DOE, and approved by the CDM EB.

Once the emission factor for the transport network has been approved, fugitive emissions may be calculated as:

$$PE_{T,y} = MIN(PE_{T,mb,y};PE_{T,ef,y})$$

With $PE_{T,mb,y}$ calculated as above and

$$PE_{T,ef,y} = L_y * EF_{pipe}$$

Where
$PE_{T,ef,y}$ = project fugitive emissions from pipeline transport in year y estimated using the pipeline emission factor (t CO_2/yr)
L_y = length of the pipeline network in year y (km)
EF_{pipe} = emission factor for the pipeline network (tCO2/km/yr)

Step 3a: Emissions from combustion installations generating electricity for the injection of the CO_2

Emissions from fossil fuel combustion in installations generating power for CO_2 injection shall be calculated in accordance with the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (version 01).

Step 3b: Venting and fugitive emissions during injection

Fugitive and vented emissions during injection of the CO_2 will be measured by continuous flow measurement at a representative point as close as possible to the point of injection.

Step 3c: Emissions from any seepage from the storage reservoir

Any seepage from the storage reservoir will be estimated according to the monitoring plan developed by the operator. The monitoring plan shall be developed in accordance with the guidance provided in Annex C.

A conservative approach will be used to avoid the underestimation of emissions and thus ensuring the environmental integrity of the CDM. This is achieved by requiring to report the emissions quantified plus an “uncertainty supplement” equal to the difference of the required uncertainty level and the achievable uncertainty level for the quantified emission amount. Based on this approach the calculation of the amount of CO_2 to be reported is as follows:

$PE_{res,,y} = ES_{,res,,y} *(1+ U_{seep95})$

With:
$PE_{,res,y}$ = Reported project emissions from seepage from the reservoir in year y
$ES_{,res,y}$ = Estimated emissions from seepage from the reservoir using the available information from monitoring.
U_{seep95} = The level of uncertainty which is associated to the quantification approach used for the leakage in question, at a confidence level of 95%.

Besides avoiding the underestimation of emissions, the approach can be expected to have a supportive effect with regards to the development of quantification approaches with higher accuracy.

Leakage

Leakage emissions considered are emissions that result from additional coal mining as a consequence of the energy penalty for retrofitting the CO_2 capture installation on the power plant:

$EL_y = EL_{penalty,\ y} + EL_{coal\ mining}$

Where:

EL_y	are the leakage emissions in year y (tCO_2)
$EL_{penalty,\ y}$	are the emissions from that has to be supplied from other sources because of the reduced efficiency as a consequence of the energy penalty (MWh)
$EL_{coal\ mining}$	emission leakage related to additional coal mining (tCO_2)

The latter is determined through:

$EL_{coal\ mining} = EF_{coal\ mining} * FC_{cap,y}$

$EF_{coal\ mining}$	is the emission factor for fugitive methane from coal mining (tCO_2-eq/t coal)
$FC_{cap,y}$	is the coal required to generate the electricity required for capturing the CO_2 in year y (t coal/MWh)

The emission factors for the additional coal mining may be based on IPCC guidance in the 2006 Revised Guidelines for National Greenhouse Gas inventories, volume 2, section 4.

The coal, required for capturing the CO_2, may be calculated as:

$FC_{cap,y} = FC_{PC,y} - FC_{el,y}$

Where:

$FC_{PC,y}$	=	coal combustion in project power plant in year *y* (t)
$FC_{el,y}$	=	coal that would need to be combusted for producing the electricity output of the project power plant in year *y* without CO_2 capture (t)

$$FC_{el,y} = \frac{EG_{PC,net,y}}{\eta_{PC} * NCV_{PC,y} * 3.6}$$

Where:

$EG_{PC,y}$	=	net electricity generated by the project power plant in year *y* (MWh)
$NCV_{PCnet,,y}$	=	net caloric value of the coal combusted in the project power plant in year y (GJ/t)
η_{PC}	=	operational efficiency of the project power plant with CO_2 capture (-/-)

Emission reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y + LE_y \qquad (1)$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO_2e/yr)
PE_y	=	Project emissions in year *y* (t CO_2/yr)
LE_y	=	Leakage emissions in year *y* (t CO_2/yr)

Changes required for methodology implementation in 2nd and 3rd crediting periods

Data and parameters not monitored

In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Data / parameter:	
Data unit:	
Description:	
Source of data:	
Measurement procedures (if any):	
Any comment:	

III. MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Data and parameters monitored

Data / parameter:	$Q_{in,y}$
Data unit	t
Description:	CO_2 flow into pipeline from capture facility in year *y*
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$Q_{out,y}$
Data unit	t
Description:	CO_2 flow out of pipeline to injection facility in year *y*
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$PE_{fugI,,y}$
Data unit	t CO_2
Description:	fugitive and vented emissions during injection
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$ES_{,res,y}$
Data unit	t CO_2
Description:	Quantification of emissions from seepage from the storage complex using the available information from monitoring.
Source of data:	
Measurement procedures (if any):	Monitoring of seepage from the storage complex shall be in line with the stipulations in Annex C to this methodology.
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{seep,95}$
Data unit	-/-
Description:	The level of uncertainty which is associated to the quantification approach used for the seepage in question at a 95% confidence level
Source of data:	Expert judgement

Data / parameter:	$U_{seep,95}$
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{pipe,95}$
Data unit	-/-
Description:	Uncertainty in continuous flow measurements of CO_2 in pipelines at a 95% confidence level
Source of data:	Expert judgement
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	L_y
Data unit	km
Description:	length of the pipeline network in year *y*
Source of data:	measurement by project participant
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	EF_{pipe}
Data unit	emission factor for the pipeline network (tCO2/km/yr)
Description:	
Source of data:	determination through extensive measurement campaigns
Measurement procedures (if any):	
Monitoring frequency	annual
QA/QC procedures:	
Any comment:	

Data / parameter:	$EG_{PC,net,y}$
Data unit	MWh
Description:	Net electricity generated in the project power plant in year *y*, i.e. excluding the electricity required for capturing the CO_2
Source of data:	Measurements by project participants
Measurement procedures (if any):	Electricity meters
Monitoring frequency	Continuously
QA/QC procedures:	The metered net electricity generation should be cross-checked with receipts from sales. Ensure that $EG_{PJ,net,y}$ is the net electricity generation (the gross generation by the project plant minus all auxiliary electricity consumption of the plant
Any comment:	

Data / parameter:	$EG_{PP,avg}$
Data unit	MWh
Description:	Average historical electricity supply from the power plant over the last 3 years prior to the project activity
Source of data:	Measurements by project participants
Measurement procedures (if any):	Electricity meters
Monitoring frequency	Continuously
QA/QC procedures:	The metered net electricity generation should be cross-checked with receipts from sales.
Any comment:	

Data / parameter:	$EG_{BL,x}$
Data unit	t CO_2/t
Description:	Net electricity generated and delivered to the grid by power plant in the baseline in year *x*
Source of data:	Measurement by project participant
Measurement procedures (if any):	Electricity meters
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{FF,BL,y}$, $EF_{FF,PC,y}$
Source of data:	Choose the CO_2 emission factor corresponding to the fuel type in the baseline and the project power plant. Use preferably well-documented and reliable regional or national average values If such data is not available, IPCC default values may be used.
Data unit	t CO_2/t
Description:	CO_2 baseline emission factor of the baseline fossil fuel type and the fossil fuel combusted in the project power plant.
Measurement procedures (if any):	--
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{GJ,PC,y}$
Data unit	t CO_2/GJ
Description:	weighted average CO_2 emission factor per GJ of the coal combusted in the project power plant in year *y*
Source of data:	Choose the CO_2 emission factor corresponding to the fuel type in the baseline and the project power plant. Use preferably well-documented and reliable regional or national average values If such data is not available, IPCC default values may be used.
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{coal\ mining}$
Data unit	t CO_2-eq/t
Description:	emission factor of fugitive methane emissions from coal mining
Source of data:	The following data sources may be used if the relevant conditions apply:

Data source	**Conditions for using the data source**
a) Values provided by the fuel supplier in invoices	This is the preferred source
b) Measurements by the project participants	If a) is not available
c) Regional or national default values	If a) is not available These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances).
d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories	If a) is not available

Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$FC_{BL,,x}$, $FC_{PC,y}$
Data unit	t
Description:	amount of fuel consumed by power plant in the baseline in year *x* resp by the power plant with capture in year *y* *j,n* or *PJ* in year *x* resp *y*
Source of data:	Fuel consumption statistics, e.g. from central-/regional regulatory authorities
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$NCV_{PC,y,}$ $NCV_{BL,,x}$
Data unit	GJ/t
Description:	net calorific value of the fossil fuel type consumed by the project power in the baseline in year *x* resp by the power plant with capture in year *y*

<table>
<tr><td>Data / parameter:</td><td>$NCV_{PC,y}$, $NCV_{BL,,x}$</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source if the carbon fraction of the fuel is not provided (option A).</td></tr>
<tr><td>b) Measurements by the project participants</td><td>If a) is not available</td></tr>
<tr><td>c) Regional or national default values</td><td>If a) is not available
These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances).</td></tr>
<tr><td>d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If a) is not available</td></tr>
</table></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>
</table>

<table>
<tr><td>Data / parameter:</td><td>w_C</td></tr>
<tr><td>Data unit</td><td>tC/ t coal</td></tr>
<tr><td>Description:</td><td>weighted average mass fraction of carbon in the coal combusted in the project power plant in year y</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source.</td></tr>
<tr><td>b) Measurements by the project participants</td><td>If a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>Measurements should be undertaken in line with national or international fuel standards.</td></tr>
<tr><td>Monitoring frequency</td><td>The mass fraction of carbon should be obtained for each fuel delivery, from which weighted average annual values should be calculated.</td></tr>
<tr><td>QA/QC procedures:</td><td>Verify if the values under a) and b) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in b) should have ISO17025 accreditation or justify that they can comply with similar quality standards.</td></tr>
<tr><td>Any comment:</td><td></td></tr>
</table>

Data / parameter:	$\eta_{n,x}$
Data unit	-/-
Description:	thermal efficiency of the power generation technology in power plant *j* in year *x*, where • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section, and • *x* is the most recent year prior to the start of the project activity for which data are available
Source of data:	
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	As a conservative approach, the efficiency should be determined as the efficiency at optimum load, e.g. as provided by the manufacturers

Data / parameter:	η_{PC}
Data unit	-/-
Description:	thermal efficiency of the power generation technology in the project power plant with CO_2 capture
Source of data:	
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	As a conservative approach, the efficiency at optimum load provided by the manufacturer should be corrected to reflect the efficiency at average load.

Section D. Explanations / justifications to the proposed new baseline and monitoring methodology

Selected approach from paragraph 48 of the CDM modalities and procedures

The operation that reduces the greenhouse gas emission is a retrofit to an existing operation, which would otherwise continue unchanged in the future. The baseline should therefore represent the existing actual emissions.

The accounting of the energy penalty is done through accounting for project emissions that compensate for the loss of electricity generated in the power plant equipped with the CO_2 capture facility. As the electricity is assumed to be supplied by the grid, the emission factor of the electricity grid (48c) should be used for this.

Applicability conditions

CO_2 capture and storage is a multi-component option for reducing greenhouse gas emissions. Emissions are not reduced unless all components are fully executed. A combination of applicability conditions is therefore necessary. Given the technical specifics of both retrofit CO_2 capture on coal-fired power plants and storage of the CO_2 in an Enhanced Coal Bed Methane recovery

(ECBM) operation, it is appropriate to set up a specific methodology for the combination of these components only. The baseline would also change considerably if the ECBM operation would already be ongoing.

Leakage

It could be considered that emissions related to the use of methane produced in the ECBM operation would count as leakage. However, the produced methane will not generate extra demand for natural gas, nor will it therefore increase global greenhouse gas emissions. This methodology therefore does not consider these emissions.

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Appendix II Illustrative CDM baseline methodology for capture of CO_2 from a newly built pulverized coal plant and its subsequent storage in depleted oil or gas fields or saline formations

CLEAN DEVELOPMENT MECHANISM
PROPOSED NEW BASELINE AND MONITORING METHODOLOGIES
(CDM-NM)
(Version 03.1)

CONTENTS

Section B. Summary and applicability of the baseline and monitoring methodology

1. Methodology title (for baseline and monitoring), submission date and version number
Capture of CO_2 from a newly built pulverized coal plant, and its subsequent storage in an aquifer

2. If this methodology is based on a previous submission or an approved methodology, please state the reference numbers (NMXXXX/AMXXXX/ACMXXXX) here. Explain briefly the main differences and their rationale.

Calculation of baseline emissions uses parts of ACM0013: Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology – Version 2.

3. Summary description of the methodology, including major baseline and monitoring methodological steps

Section C. Proposed new baseline and monitoring methodology

Draft baseline and monitoring methodology AMXXXX

"Methodology title"

I. SOURCE, DEFINITIONS AND APPLICABILITY

Sources

This consolidated baseline and monitoring methodology is based on [elements from] the following [approved baseline and monitoring methodologies and] proposed new methodologies:

- ACM0013: Consolidated baseline and monitoring methodology for new grid connected fossil fuel fire power plants using a less GHG intensive technology – Version 2.

This methodology also refers to the latest approved versions of the following tools (please delete those not applicable):

- Tool for the demonstration and assessment of additionality
- Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion

For more information regarding the proposed new methodologies and the tools as well as their consideration by the Executive Board please refer to http://cdm.unfccc.int/goto/MPappmeth.

Selected approach from paragraph 48 of the CDM modalities and procedures

This new methodology uses "Economically attractive course of action (48b)".

Definitions: Please provide definitions of key terms that are used in this proposed new methodology

For the purpose of this methodology, the following definitions apply:

- **Geological storage of CO_2** means injection into and storage of CO_2 streams in underground geological formations;
- **Reservoir or storage reservoir** means a specific geological formation used for the geological storage of CO_2;
- **Geological formation** means a lithostratigraphical subdivision within which distinct rock layers can be found and mapped;
- **Seepage** means any release of CO_2 from the storage complex;
- **Storage complex** means the storage reservoir and surrounding geological domains which can have an effect on overall storage integrity and security (*i.e.*, secondary containment formations);
- **Exploration** means assessing potential storage complexes by means of a specific procedure including activities such as carrying out geological surveys by physical or chemical means and drilling to obtain geological information about strata in the potential storage complex;

- **Operator** means any natural or legal, private or public person who operates or controls the storage site or to whom decisive economic power over the technical functioning of the storage site has been delegated according to national legislation; This person may change from the storage preparations to the post-closure phase;
- **Substantial change** means a change which may have significant effects on the environment;
- **CO_2 stream** means a flow of substances that results from carbon dioxide capture processes;
- **CO_2 plume** means the dispersing volume of CO_2 in the geological formation;
- **Migration** means the movement of CO_2 within the storage complex;
- **Significant irregularity** means any irregularity in the injection or storage operations or in the condition of the site itself, which implies the risk of a leakage;
- **Corrective measures** means any measures taken to correct significant irregularities or to close leakages in order to prevent or minimise the release of CO_2 from the storage complex;
- **Closure of a CO_2 storage site** means the definite cessation of CO_2 injection into that storage site;
- **Post-closure** means the period after the closure of a storage site, including the period after the transfer of responsibility to the competent authority;
- **Transport network** means the network of pipelines, including associated booster stations, for the transport of CO_2 to the storage site.
- **Saline formation** means a sediment or rock body containing brackish water or brine.
- **Net quantity of electricity generated** means the total electricity produced by a power plant minus the electricity required for capturing the CO.

Applicability conditions

This methodology applies to project activities that involve the construction of new coal fired power plants and that capture CO_2 from these coal-fired power plants, transport it, and store it in a saline formation. CO_2 capture and storage is a multi-component option for reducing greenhouse gas emissions. Emissions are not reduced unless all components are fully executed. A combination of applicability conditions is therefore necessary. Given the technical specifics of both CO_2 capture from newly built coal-fired power plants and storage of the CO_2 in a saline formation, it is appropriate to set up a specific methodology for the combination of these components only.

The methodology is applicable under the following conditions:

- Electricity required for capturing the CO_2 is produced in the project power plant itself.
- The generic requirements for site selection, monitoring, site development and liability (Annex A) are met, regardless of any legal framework for CCS operations that host country may or may not have in place.
- The power plant is not a cogeneration plant;
- The CO_2 stream transported by pipeline to the storage location shall consist overwhelmingly of carbon dioxide. To this end, no waste and other matter may be added for the purpose of disposing of that waste or other matter. However, a CO_2 stream may contain incidental associated substances from the source, capture or injection process. Concentrations of those substances shall be below levels that would adversely affect the integrity of the storage site and relevant transport infrastructure and pose a significant risk to the environment.
- Injection the CO_2 in its supercritical or liquefied form, with no intention of ever recovering it, in a saline formation
- Appropriate site development in accordance with Annex A
- Appropriate site characterization and selection in accordance with Annexes A and B.
- An appropriate monitoring plan in accordance with Annexes A and C.

In addition, the applicability conditions included in the tools referred to above apply.

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

The spatial extent of the project boundary includes the coal-fired power plant, the capture installation, the transport facilities, and the storage complex, including both the reservoir and the surrounding geological domains.

Project emissions include emissions from:
a) the project power plant and capture installation:
- the combustion installation

b) emissions during transport of the CO_2:
- compression installations along the CO_2 pipeline
- fugitive emissions along the CO_2 pipeline

c) emissions during injections and storage:
- combustion installations generating electricity for the injection of the CO_2
- fugitive and vented emissions at injection
- fugitive emissions from the storage complex ("seepage")

The greenhouse gases included in or excluded from the project boundary are shown in Table 3.

Table 3: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Fossil fuel combustion in baseline	CO_2	Yes	Main emission source
		CH_4	No	Considered negligible
		N_2O	No	Considered negligible
Project Activity	Project power plant incl capture	CO_2	Yes	Main emission source. This will include any non-captured CO_2, as well as the CO_2 resulting from energy use in the capture process.
		CH_4	No	Considered negligible
		N_2O	No	Considered negligible
	Transport	CO_2	Yes	This includes any fugitive emissions from the injection installation and the pipeline, as well as emissions from combustion in the booster installations
		CH_4	No	Considered negligible
		N_2O	No	Considered negligible
	Injection:	CO_2	Yes	This includes emissions from the combustion needed to run the injection installation, as well as fugitive and vented CO_2 emissions during injection.
		CH_4	No	Considered negligible
		N_2O	No	Considered negligible
	Storage Seepage	CO_2	Yes	This regards unintended seepage from the storage complex.
		CH_4	No	Considered negligible
		N_2O	No	Considered negligible

Identification of the baseline scenario and demonstration of additionality

The tool for the demonstration and assessment of additionality is used. Clarifications to the use of the various steps of the tool in this methodology are listed below.

Step 1: Alternatives to the project activity
In substep 1 ('Define alternatives to the project activity') alternatives will be established for:

d. the way power would be generated in absence of the project activity
e. the fate of the CO_2 in absence of the project activity
f. the state of the storage complex in absence of the project activity.

Step 2: Investment analysisCO_2

In order to demonstrate additionality an investment analysis (step 2) is mandatory, as is the case for new power plants, analogous to ACM0013. An investment analysis shall be made to assess the each of the alternatives listed above, i.e. for power generation, for the fate of the CO_2, and for the state of the storage complex.
Furthermore, in sub-step 2a an investment comparison analysis (Option II) or the benchmark analysis (Option III) shall be used. A simple cost analysis is not appropriate, since the tool only allows this if the CDM project activity and the alternatives identified in Step 1 do not generate other than CDM related income. Both the project plant and its alternatives will also benefit from revenues from the electricity generated.

Step 3: Barrier analysis

A barrier analysis by itself is insufficient to demonstrate additionality, and may only be used to support the investment analysis.

Step 4: Common practice analysis

Since worldwide, there are no CCS projects that either capture most of the CO_2 from a coal-fired power plant, this activity can safely be assumed to be not consistent with common practice. CO_2

Baseline emissions

Baseline emissions are calculated for the economically most attractive baseline scenario – a NGCC without CO_2 capture and storage. The methodology below is based on the consolidated baseline and monitoring methodology for new grid connected fossil fuel fire power plants using a less GHG intensive technology – Version 2 (ACM0013).

Electricity generated in the baseline is assumed to equal:

$$EG_{BL,y} = EG_{PCnet,y} + EG_{PCcap,y}$$

Where:

$EG_{BL,y}$	=	electricity generated in the baseline (MWh)
$EG_{PCnet,y}$	=	net electricity generated in the project power plant, i.e. excluding the electricity required for capturing the CO_2 (MWh)
$EG_{PCcap,y}$	=	electricity required for capturing the CO_2 generated in the project power plant (MWh)

Baseline emissions are calculated for both parts of the electricity generation in the equation above, as follows:
CO_2 $_{CO2}$

$BE_y = EG_{PC,net,y} \times EF_{BL,y} + EG_{PC,cap,y} \times MIN(EF_{BL,y};EF_{grid,,BM,y,};EF_{grid,OM,y})$
(1)

Where:

BE_y	=	baseline emissions in year y (tCO2)
$EF_{BL,y}$	=	baseline emission factor in year y (tCO2/MWh)
$EF_{grid,BM,y}$	=	grid emission factor based on the built margin in year y (t CO_2/MWh)
$EF_{grid,OM,y}$	=	grid emission factor based on the operating margin in year y (t CO_2/MWh)

The grid emission factors $EF_{grid,BM,y}$ and $EF_{grid,OM,y}$ will be calculated using the “Tool to calculate the emission factor for an electricity system”.

$EF_{BL,y}$ will be determined using the lower value between the emission factor of the technology and fuel type that has been identified as the most likely baseline scenario and a benchmark emission factor determined based on the performance of the top 20% power plants that use the same fuel as the project plant and any technology available in the geographical area as defined in Step 2 below.

Project participants shall use for $EF_{BL,y}$ the lowest value among the following two options:

Option 1: The emission factor of the technology and fuel identified as the most likely baseline scenario
under “Identification of the baseline scenario” section above, and calculated as follows:

$$EF_{BL,y} = \frac{EF_{FF,BL,y}}{\eta_{BL}} * 3.6 \quad GJ/MWh \qquad (2)$$

Where:

$EF_{BL,y}$	=	the baseline emission factor in year *y* (tCO2/MWh)
$EF_{FF,BL,y}$	=	the CO_2 baseline emission factor of the baseline fossil fuel type that has been identified as the most likely baseline scenario (tCO2/t)
η_{BL}	=	energy efficiency of the power generation technology that has been identified as the most likely baseline scenario

$EF_{FF,BL,y}$ will be based on the emission factors provided in the 2006 IPCC Guidelines for National Greenhouse Gas inventories, volume 2, section 2.3.2. The highest tier possible shall be used.

Option 2: The average emissions intensity of all power plants *j* corresponding to the power plants whose performance is among the top 20 % of their category, as follows:

$$EF_{BL,y} = \frac{\sum_{j} FC_{j,x} * NCV_{j,x} * EF_{j,x}}{\sum_{j,x} EG_j} \qquad (3)$$

Where:

$EF_{BL,y}$	=	baseline emission factor in year *y* (tCO2/MWh)
$FC_{j,x}$	=	amount of fuel consumed by power plant *j* in year *x* (t)
$NCV_{j,x}$	=	net calorific value of the fossil fuel type consumed by power plant j in year x (GJ/t)
$EF_{j,x}$	=	CO_2 emission factor of the fossil fuel type consumed by power plant j in year x (tCO2/t)

$EG_{j,x}$ = net electricity generated and delivered to the grid by power plant j in year x (MWh)

x = most recent year prior to the start of the project activity for which data is available

j = one of top 20% performing power plants (excluding cogeneration plants and including power plants registered as CDM project activities), as identified below, among all power plants in a defined geographical area that have a similar size, are operated at similar load and use the same fuel type as the project activity

Note: That in case of option 2, $EB_{BL,y}$ is not monitored annually but only calculated once at the start of the crediting period and updated at the renewal of a crediting period.

For determination of the top 20% performer power plants *j*, the following step-wise approach is used:

Step 1: Definition of similar plants to the project activity

The sample group of similar power plants should consist of all power plants (except for cogeneration power plants) that:

- use the same fossil fuel type as the project activity, where fuel types are defined in the following categories:
  - Coal;
  - Oils (e.g. diesel, kerosene, residual oil);
  - Natural gas.
- have been constructed in the previous five years;
- have a comparable size to the project activity. Plants with a comparable size to the project activity will need to have a capacity between 60% and 94% of the rated capacity of the project plant, to make up for the energy penalty (typically 24-40% for pulverized coal plants);
- are operated in the same load category, i.e. at peak load (defined as a load factor of less than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year) as the project activity; and
- have operated (supplied electricity to the grid) in the year prior to the start of the project activity.

Step 2: Definition of the geographical area

The geographical area to identify similar power plants should be chosen in a manner that the total number of power plants "N" in the sample group comprises at least 10 plants. As a default, the grid to which the project plant will be connected should be used[10]. If the number of similar plants, as defined in Step 1, within the grid boundary is less than 10, the geographical area should be extended to the country. If the number of similar plants is still less than 10, the geographical area should be extended by including all neighbouring non-Annex I countries. If the number remains to be less than 10, all non-Annex I countries in the continent should be considered.

If the necessary data on power plants of the sample group in the relevant geographical area are not available, or if there are less than 10 similar power plants in all non-Annex I countries in the continent, then data from power plants annex I or OECD countries can be used instead.

Step 3: Identification of the sample group

Identify all power plants *n* that are to be included in the sample group. Determine the total number "N" of all identified power plants that use the same fuel as the project plant and any technology available within the geographical area, as defined in Step 2 above.

[10] The grid boundary is defined as per the approved consolidated baseline and monitoring methodology ACM0002.

The sample group should also include all power plants within the geographical area registered as CDM project activities, which meet the criteria defined in Step 1 above.

Step 4: Determination of the plant efficiencies
Calculate the operational efficiency of each power plant *n* identified in the previous step. The most recent one-year data available shall be used. The operational efficiency of each power plant *n* in the sample group is calculated as follows:

$$\eta_{n,x} = \frac{EG_{n,x}}{FC_{nx} * NCV_{n,x} * 277.8}$$

Where:

$EG_{n,x}$	=	the net electricity generated and delivered to the grid by the power plant *n* in the year *x* (MWh)
$FC_{n,x}$	=	the quantity of fuel consumed in the power plant *n* in year *x* (t)
$NCV_{n,x}$	=	the net calorific value of the fuel type fired in power plant n in year *y* (GJ/t)
277.8	=	conversion factor from TJ to MWh
n	=	number of power plants in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity
x	=	most recent year prior to the start of the project activity for which data are available

Step 5: Identification of the top 20% performer plants j
Sort the sample group of *N* plants from the power plants with the highest to the lowest operational
efficiency. Identify the top 20% performer plants *j* as the plants with the 1st to Jth highest operational
efficiency, where the *J* (the total number of plants *j*) is calculated as the product of N (the total number of plants *n* identified in step 3) and 20%, rounded down if it is decimal. If the generation of all identified plants *j* (the top 20% performers) is less than 20% of the total generation of all plants n (the whole sample group), then the number of plants *j* included in the top 20% performer group should be enlarged until the group represents at least 20% of total generation of all plants *n*.

All Steps should be documented transparently, including a list of the plants identified in Steps 3 and 5, as
well as relevant data on the fuel consumption and electricity generation of all identified power plants.

Project emissions

The project activity is the on-site combustion of coal in the project plant to generate electricity, the capture of the CO_2 and its subsequent transport through a pipeline network to be injected in a saline formation. Project emissions include emissions from:

1) the project power plant and capture installation:

2) emission during transport of the CO_2:
- booster installations along the CO_2 pipeline
- fugitive emissions along the CO_2 pipeline

3) emissions during injection and storage:
- combustion installations generating electricity for the injection of the CO_2
- fugitive emissions from the storage complex (“seepage”)

Project emissions are estimated in the following steps:

Step 1: Calculation of the CO_2 emission of the power plant with capture ($PE_{PC,,y}$)

Step 2a: Emission from booster installations along the CO_2 pipeline (PE_{boo})

Step 2b: Emissions from any seepage from the transport infrastructure ($PE_{fug,T,y}$)

Step 3a: Fugitive and vented emissions during injection of the CO_2 ($PE_{fug,I,,y}$)

Step 3b: Emissions from combustion installations generating electricity for the injection of the CO_2 ($PE_{com,I,,y}$)

Step 3c: Emissions from any seepage from the storage complex ($PE_{res,y}$)

Applying these steps, the total project emissions are:

$$PE_y = PE_{PC,y} + PE_{boo,T,y} + PE_{fug,T,y} + PE_{fug,I,y} + PE_{com,I,y} + PE_{res,y}$$

Where:

PE_y	are the project emissions in year *y* (tCO_2)
$PE_{PC,\,y}$	are the remaining project emissions from the power plant in year y (tCO_2)
$PE_{boo,T,y}$	are emissions from booster installations along the transport infrastructure (tCO_2)
$PE_{fugT,,y}$	are fugitive emissions from the transport infrastructure (tCO_2)
$PE_{fugI,,y}$	are fugitive and vented emissions during injection (tCO_2)
$PE_{com,I,y}$	are emissions from combustion installations generating electricity for the injection of the CO_2 (tCO_2)
$PE_{res,y}$	is seepage from the storage complex (tCO_2)

Step 1: Calculation of the CO_2 emission of the power plant with capture

Remaining CO_2 emissions from fossil fuel combustion in the project power plant with capture are calculated based on the combusted coal and the CO_2 stream fed into the pipeline network, as follows:

$$PE_{PC,y} = FC_{PC,y} * EF_{FF,PC,y} - Q_{in,y} * (1-U_{pipe,95})$$

Where:

$PE_{PC,,y}$	=	CO_2 emissions from fossil fuel combustion in power generation after capture during year y (tCO2/yr
$FC_{PC,y}$	=	quantity of coal combusted during year y (t)
$EF_{FF,PC,y}$	=	CO_2 emission coefficient of the coal combusted in the project power plant in year *y* (tCO2/t coal)
$Q_{in,y}$	=	measured CO_2 flow from the capture installation to the pipeline (t/yr)
$U_{pipe,5}$	=	measurement uncertainty at a 95% confidence level (-/-)

As a conservative assumption, the measured CO_2 flow from the capture installation to the pipeline is adjusted downward by correcting the measurement for the measurement uncertainty.

In line with the tool, the CO_2 emission coefficient $EF_{PC,y}$ can be calculated following two procedures, depending on the available data.

Option A: $EF_{PC,y}$ is calculated based on the chemical composition of the coal, as follows:

$EF_{FF,PC,y} = w_c * 44/12$

Where
w_C = weighted average mass fraction of carbon in the coal (tC/ t coal)

Option B: $EF_{PC,y}$ is calculated based on the net caloric value and CO_2 emission factor of the coal, as follows:

$EF_{,FF,PCC,y} = NCV_{PC,y} * EF_{GJ,PC,y}$

Where:

$NCV_{PJ,y}$ = net caloric value of the coal combusted in the project power plant in year y (GJ/t)

$EF_{GJ,PC,y}$ = weighted average CO_2 emission factor of the coal combusted in the project power plant in year y (tCO2/GJ

Step 2a: Emissions from booster installations along the CO_2 pipeline

Combustion emission from fuel use in booster installations shall be calculated in accordance with the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (version 01).

Step 2b: Fugitive emissions from the transport infrastructure

Emissions from transport will be calculated using a mass balance approach. While continuous measurements of CO_2 flows are surrounded by a measurement uncertainty, a conservative estimate needs to be made. Therefore, measured values for the CO_2 mass flow into and out of the pipeline will be corrected as follows:

$PE_{T,y} = PE_{T,mb,y} = Q_{in,y} * (1+U_{pipe,95}) – Q_{out,y} * (1-U_{pipe,95})$

Where:

$PE_{T,y}$ = project fugitive emissions from pipeline transport in year *y* (t/yr)
$PE_{T,mb,y}$ = project fugitive emissions from pipeline transport in year y estimated by a mass balance approach (t CO_2/yr)
$Q_{in,y}$ measured CO_2 flow from the capture installation to the pipeline (t/yr)
$Q_{out,y}$ = measured CO_2 flow out of pipeline to injection facility (t/yr)
$U_{pipe,95}$ = measurement uncertainty at a 95% confidence level (-/-)

Note: if mass balance leads to negative emissions, emissions will be assumed to be zero.

In the PDD the project developer shall elaborate a measurement campaign in order to estimate an emission factor for the pipeline network EF_{pipe} (tCO2/km/yr). Measurements will be conducted every year at representative locations of the transport network where leaks can be expected, e.g. at booster stations and pipeline joints. The emission factor shall be derived from the measurement results using statistical methods and taking into consideration the structure of the transport pipeline system, e.g. the number of booster stations, joints, etc. The development of the emission factor shall be documented and reported in detail, verified by an accredited DOE, and approved by the CDM EB.

Once the emission factor for the transport network has been approved, fugitive emissions may be calculated as:

$PE_{T,y} = MIN(PE_{T,mb,y};PE_{T,ef,y})$

With $PE_{T,mb,y}$ calculated as above and

$PE_{T,ef,y} = L_y * EF_{pipe}$

Where

$PE_{T,ef,y}$	=	project fugitive emissions from pipeline transport in year y estimated using the pipeline emission factor (t CO_2/yr)
L_y	=	length of the pipeline network in year y (km)
EF_{pipe}	=	emission factor for the pipeline network (tCO2/km/yr)

Step 3a: Emissions from combustion installations generating electricity for the injection of the CO_2

Emissions from fossil fuel combustion in installations generating power for CO_2 injection shall be calculated in accordance with the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (version 01).

Step 3b: Venting and fugitive emissions during injection

Fugitive and vented emissions during injection of the CO_2 will be measured by continuous flow measurement at a representative point as close as possible to the point of injection.

Step 3c: Emissions from any seepage from the storage complex

Any seepage from the storage complex will be estimated according to the monitoring plan developed by the operator. The monitoring plan shall be developed in accordance with the guidance provided in Annex C.

A conservative approach will be used to avoid the underestimation of emissions and thus ensuring the environmental integrity of the CDM. This is achieved by requiring to report the emissions quantified plus an "uncertainty supplement". Based on this approach the calculation of the amount of CO_2 to be reported is as follows:

$PE_{res,,y} = ES_{,res,y} *(1+ U_{seep95})$

With:

$PE_{,res,y}$ = Reported project emissions from seepage from the reservoir in year *y*

$ES_{,res,,y}$ = Estimated emissions from seepage from the storage complex using the available information from monitoring.

U_{seep95} = The level of uncertainty which is associated to the quantification approach used for the leakage in question, at a confidence level of 95%.

Besides avoiding the underestimation of emissions, the approach can be expected to have a supportive effect with regards to the development of quantification approaches with higher accuracy.

Leakage

Leakage emissions are any emissions occurring outside the project boundary that are directly caused by the project activity. They consist of emissions resulting from mining the additional coal fed into the power plant, as a consequence of the additional electricity produced, as follows:

$EL_y = FC_{cap,\,y} * EF_{coal\ mining}$

Where:

EL_y	are the leakage emissions in year *y* (tCO_2)
$FC_{cap,y}$	coal required for capturing the CO_2, combusted in year *y* (t)
$EF_{coal\ mining}$	is the emission factor of fugitive methane emissions from coal mining (t CO_2-eq/t)

$EF_{coal\ mining}$ may be based on the default emission factors provided in the 2006 IPCC Guidelines for National Greenhouse Gas inventories, volume 2, section 4.

The coal, required for capturing the CO_2, may be calculated as:

$FC_{cap,y} = FC_{PC,y} - FC_{el,y}$

Where:

$FC_{PC,y}$	=	coal combustion in project power plant in year *y* (t)
$FC_{el,y}$	=	coal that would need to be combusted for producing the electricity output of the project power plant in year *y* without CO_2 capture (t)

$$FC_{el,y} = \frac{EG_{PC,net,y}}{\eta_{PP} * NCV_{PC,y} * 3.6}$$

Where:

$EG_{PC,y}$	=	net electricity generated by the project power plant in year *y* (MWh)
$NCV_{PCnet,,y}$	=	net caloric value of the coal combusted in the project power plant in year y (GJ/t)
η_{pp}	=	operational efficiency of the project power plant if no CO_2 were captured (-/-)

Note that $FC_{el,y}$ is equal to the fuel combustion in the baseline scenario if the selected baseline is a new pulverized coal plant without CCS.

Operational efficiency of the project power plant will be estimated conservatively, as follows:

$\eta_{PP} = \text{MIN}(\eta_{dft}; \eta_{n,x})$

Where:

η_{dft}	=	default operational efficiency (-/-)
$\eta_{n,x}$	=	benchmark efficiency based on the top20% of similar power plants n
n	=	all power plants in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity

The calculation of the benchmark efficiency $\eta_{n,x}$ has been elaborated in the section 'Baseline emissions' above.

Emission reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y + LE_y \quad \textbf{(2)}$$

Where:

ER_y	=	Emission reductions in year y (t CO_2e/yr)
BE_y	=	Baseline emissions in year y (t CO_2e/yr)
PE_y	=	Project emissions in year y (t CO_2/yr)
LE_y	=	Leakage emissions in year y (t CO_2/yr)

Changes required for methodology implementation in 2nd and 3rd crediting periods

Baseline emissions in the 2nd and 3rd period will be recalculated according to the baseline methodology outlined here, and no further changes are required. It is likely that, because of the operational costs of CCS, the project activity will be stopped after the 3rd period ends.

Data and parameters not monitored

In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Data / parameter:	
Data unit:	
Description:	
Source of data:	
Measurement procedures (if any):	
Any comment:	

III. MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

For monitoring project emissions from combustion of fossil fuels in the project plant and for monitoring guidance in the latest approved version of the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion should be applied.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Data and parameters monitored

Below an overview is provided of all variables needed to determine reduced emissions in the project activity, including statistical data, monitored parameters, and calculated variables.

Data / parameter:	$Q_{in,y}$
Data unit	t
Description:	CO_2 flow from the capture installation to the pipeline in year *y*
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$Q_{out,y}$
Data unit	t
Description:	CO_2 flow out of pipeline to injection facility in year *y*
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$PE_{fugI,,y}$
Data unit	t CO_2
Description:	fugitive and vented emissions during injection
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$ES_{,res,y}$
Data unit	t CO_2
Description:	Quantification of emissions from seepage from the storage complex using the available information from monitoring.
Source of data:	
Measurement procedures (if any):	Monitoring of seepage from the storage complex shall be in line with the stipulations in Annex C to this methodology.
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{seep,95}$
Data unit	-/-
Description:	The level of uncertainty which is associated to the quantification approach used for the seepage in question at a 95% confidence level
Source of data:	Expert judgement
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{pipe,95}$
Data unit	-/-
Description:	Uncertainty in continuous flow measurements of CO_2 in pipelines at a 95% confidence level
Source of data:	Expert judgement
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	L_y
Data unit	km
Description:	length of the pipeline network in year *y*
Source of data:	measurement by project participant
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	EF_{pipe}
Data unit	emission factor for the pipeline network (tCO2/km/yr)
Description:	
Source of data:	determination through extensive measurement campaigns
Measurement procedures (if any):	
Monitoring frequency	annual
QA/QC procedures:	
Any comment:	

Data / parameter:	$EG_{PC,net}$
Data unit	MWh
Description:	net electricity generated in the project power plant, i.e. excluding the electricity required for capturing the CO_2
Source of data:	Measurements by project participants
Measurement procedures (if any):	Electricity meters
Monitoring frequency	Continuously
QA/QC procedures:	The metered net electricity generation should be cross-checked with receipts from sales. Ensure that $EG_{PJ,net,y}$ is the net electricity generation (the gross generation by the project plant minus all auxiliary electricity consumption of the plant
Any comment:	

Data / parameter:	$EG_{PC,cap}$
Data unit	MWh
Description:	electricity required for capturing the CO_2 generated in the project power plant
Source of data:	Measurements by project participants
Measurement procedures (if any):	Electricity meters
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$EG_{j,x}$, $EG_{n,x}$
Data unit	t CO_2/t
Description:	Net electricity generated and delivered to the grid by power plant j in year x where • *j* are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use the same fuel type as the project activity and any technology available within the geographical area, as defined in Step 2 under “Baseline emissions” section • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity and any technology available within the geographical area, as defined in Step 2 under “Baseline emissions” section, • *x* is the most recent year prior to the start of the project activity for which data are available
Source of data:	Electricity generation statistics, e.g. from national or regional regulatory authorities
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{FF,BL,y}$, $EF_{FF,PC,y}$
Source of data:	Choose the CO_2 emission factor corresponding to the fuel type in the baseline and the project power plant. Use preferably well-documented and reliable regional or national average values If such data is not available, IPCC default values may be used.
Data unit	t CO_2/t
Description:	CO_2 baseline emission factor of the baseline fossil fuel type and the fossil fuel combusted in the project power plant.
Measurement procedures (if any):	--
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{GJ,PC,y}$
Data unit	t CO_2/GJ
Description:	weighted average CO_2 emission factor per GJ of the coal combusted in the project power plant in year *y*
Source of data:	Choose the CO_2 emission factor corresponding to the fuel type in the baseline and the project power plant. Use preferably well-documented and reliable regional or national average values If such data is not available, IPCC default values may be used.
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{j,x}$
Data unit	t CO_2/t
Description:	The CO_2 emission factor of the fossil fuel type consumed by power plant j in year x where • *j* are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use the same fuel type as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section • *x* is the most recent year prior to the start of the project activity for which data are available
Source of data:	Choose the CO_2 emission factor corresponding to the fuel type in the baseline and the project power plant. Use preferably well-documented and reliable regional or national average values If such data is not available, IPCC default values may be used.
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$EF_{coal\ mining}$
Data unit	t CO_2-eq/t
Description:	emission factor of fugitive methane emissions from coal mining
Source of data:	The following data sources may be used if the relevant conditions apply:

Data / parameter:	$EF_{coal\ mining}$
	<table><tr><th>Data source</th><th>Conditions for using the data source</th></tr><tr><td>a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr><tr><td>b) Measurements by the project participants</td><td>If a) is not available</td></tr><tr><td>c) Regional or national default values</td><td>If a) is not available These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances).</td></tr><tr><td>d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If a) is not available</td></tr></table>
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$FC_{j,x}$, $FC_{n,x}$, $FC_{PC,y}$
Data unit	t
Description:	amount of fuel consumed by power plant *j,n* or *PJ* in year *x* resp *y*, where • *j* are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use the same fuel type as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section, • *PJ* refers to the project power plant • *x* is the most recent year prior to the start of the project activity for which data are available • *y* is the year for which emissions are reported refers to the project power plant
Source of data:	Fuel consumption statistics, e.g. from central-/regional regulatory authorities
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

<table>
<tr><td>Data / parameter:</td><td>$NCV_{PC,y}$, $NCV_{j,x}$, $NCV_{n,x}$</td></tr>
<tr><td>Data unit</td><td>GJ/t</td></tr>
<tr><td>Description:</td><td>net calorific value of the fossil fuel type consumed by the project power plant resp. power plant j or n in year x or y, where:
• j are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use the same fuel type as the project activity and any technology available within the geographical area, as defined in Step 2 under “Baseline emissions” section
• n are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity and any technology available within the geographical area, as defined in Step 2 under “Baseline emissions” section, and
• x is the most recent year prior to the start of the project activity for which data are available</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source if the carbon fraction of the fuel is not provided (option A).</td></tr>
<tr><td>b) Measurements by the project participants</td><td>If a) is not available</td></tr>
<tr><td>c) Regional or national default values</td><td>If a) is not available
These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances).</td></tr>
<tr><td>d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If a) is not available</td></tr>
</table></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>
</table>

<table>
<tr><td>Data / parameter:</td><td>w_C</td></tr>
<tr><td>Data unit</td><td>tC/ t coal</td></tr>
<tr><td>Description:</td><td>weighted average mass fraction of carbon in the coal combusted in the project power plant in year y</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source.</td></tr>
<tr><td>b) Measurements by the project participants</td><td>If a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>Measurements should be undertaken in line with national or international fuel standards.</td></tr>
</table>

Data / parameter:	w_C
Monitoring frequency	The mass fraction of carbon should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
QA/QC procedures:	Verify if the values under a) and b) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in b) should have ISO17025 accreditation or justify that they can comply with similar quality standards.
Any comment:	

Data / parameter:	$\eta_{n,x}$,
Data unit	-/-
Description:	thermal efficiency of the power generation technology in power plant *j* in year *x*, where • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section, and • *x* is the most recent year prior to the start of the project activity for which data are available
Source of data:	
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	As a conservative approach, the efficiency should be determined as the efficiency at optimum load, e.g. as provided by the manufacturers

Data / parameter:	η_{dft}
Data unit	-/-
Description:	default operational efficiency of the power generation technology in the project power plant
Source of data:	technical literature or information from the manufacturers of the equipment
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	As a conservative approach, the efficiency at optimum load provided by the manufacturer should be corrected to reflect as the efficiency at average load.

Section D. Explanations / justifications to the proposed new baseline and monitoring methodology

Selected approach from paragraph 48 of the CDM modalities and procedures

Post-combustion capture from newly built pulverized coal plants is likely to be an important CCS option in many developing countries. The baseline for this technology should represent an economically attractive course of action, which can be derived from the combined margin of the electricity grid (Tool to calculate the mission factor for an electricity system, EB 35 report Annex 12).

CO_2 will be capture from a newly built power plant. Therefore, baseline emissions cannot be based on actual or historical emissions. Furthermore, average emissions of similar project activities in the previous five years will be difficult to determine as well, mostly because CCS is a relatively new technology. In absence of the CO_2 capture and storage operation proposed under the CDM, the electricity to be produced by the newly built pulverized coal plant would most likely have been generated by other fossil fuel based and/or renewable capacity in the grid. Thus, the composition of the existing fleet must be the starting point for calculating emissions in an economically attractive course of action.

Emissions related to the energy penalty for capturing the CO_2 in this new plant are accounted for in the emissions from the total fuel combusted in the plant, which includes the fuel for the energy penalty.

Appendix III Illustrative CDM baseline methodology for capture of CO_2 from a natural gas processing plant and its storage in depleted oil or gas fields or saline formations

CLEAN DEVELOPMENT MECHANISM
PROPOSED NEW BASELINE AND MONITORING METHODOLOGIES
(CDM-NM)
(Version 03.1)

CONTENTS

Section B. Summary and applicability of the baseline and monitoring methodology

1. Methodology title (for baseline and monitoring), submission date and version number
The capture of CO_2 from natural gas processing and storage in depleted oil or gas fields or saline aquifers.

2. If this methodology is based on a previous submission or an approved methodology, please state the reference numbers (NMXXXX/AMXXXX/ACMXXXX) here. Explain briefly the main differences and their rationale.
This New Methodology is based on NM0168, with the main differences being the calculation of project emissions, the CO_2 storage aspects and the treatment of seepage, as these parts needed improvement.

3. Summary description of the methodology, including major baseline and monitoring methodological steps

Natural gas produced from underground fields contains acid components, such as CO_2, water and H_2S. In order to meet end-user and transport specifications, these need to be removed from the natural gas. The normal practice is to vent the separated CO_2 to the atmosphere.

In the project activity the separated CO_2, containing H_2S and thus acid gas, is compressed, transported by pipelines or ships, recompressed to supercritical phase, and injected in an offshore underground reservoir, such as an abandoned oil or gas field, or a saline aquifer.

Determination of the baseline scenario
Possible alternatives to the project activity are: the project activity implemented without the CDM, utilisation of the separated CO_2 in industry or agriculture, ending of natural gas production from the current reservoirs, and continuation of the current situation. The latter is thought to be the most plausible baseline scenario.

Additionality assessment:
Will be demonstrated by using the latest available tool provided by the CDM EB.

Project boundary / baseline emissions
Included in the project boundary are the following emission sources:

- CO_2 compression operation, including the facility for producing the energy for compression, and eventual seepage from the compression facility.
- CO_2 transportation system (eventual additional energy consumption and seepage).
- CO_2 storage site (energy consumption during injection, seepage).

In the baseline scenario the CO_2 emissions vented after the acid gas separation are included.

Leakage
There is no leakage involved, as all emission sources are covered with the project boundary. In the baseline scenario analysis, it is also proven that the CDM project will not lead to prolonged technical lifetime of the gas production facility.

Emission reductions
ER = baseline emissions – project emissions =
= CO_2 vented from acid gas separation – CO_2 from energy consumption – CO_2 seepage

Section C. Proposed new baseline and monitoring methodology

Draft baseline and monitoring methodology AMXXXX

"The capture of CO_2 from natural gas processing and storage in depleted oil or gas fields or saline aquifers"

I. SOURCE, DEFINITIONS AND APPLICABILITY

Sources

This consolidated baseline and monitoring methodology is based on elements from the following proposed new methodologies:

- NM0168 "The capture of CO_2 from natural gas processing plants and liquefied natural gas (LNG) plants and its storage in underground aquifers or abandoned oil/gas reservoirs" Version 1.0

This methodology also refers to the latest approved versions of the following tools (please delete those not applicable):

- Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion
- Tool for the demonstration and assessment of additionality

Selected approach from paragraph 48 of the CDM modalities and procedures

This new methodology uses "Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment" (48b)

Definitions: Please provide definitions of key terms that are used in this proposed new methodology

2. For the purpose of this methodology, the following definitions apply:

- **Natural gas processing:** see acid gas separation.
- **Acid (or sour) gas separation:** The separation of natural gas from acid gases, mostly a mixture of H_2S and CO_2, that naturally occur in significant quantities.
- **Geological CO_2 storage:** A process for retaining captured CO_2 in a geological reservoir underground so that it does not reach the atmosphere. Geological reservoirs include oil or gas fields, coal fields, or saline aquifers.
- **Saline aquifer:** Sediment or rock body containing brackish water or brine.
- **Depleted oil/gas field:** an oil or gas field where production is significantly reduced.
- **Storage complex:** the storage site and surrounding geological domains which can have an effect on overall storage integrity and security (*i.e.*, secondary containment formations);

- **Geological storage of CO_2**: injection into and storage of CO_2 streams in underground geological formations;

- **Reservoir or storage reservoir:** a specific geological formation used for the geological storage of CO_2;

- **Geological formation**: a lithostratigraphical subdivision within which distinct rock layers can be found and mapped;

- **Seepage**: any release of CO_2 from the storage complex;

- **Exploration**: assessing potential storage complexes by means of a specific procedure including activities such as carrying out geological surveys by physical or chemical means and drilling to obtain geological information about strata in the potential storage complex;

- **Operator:** any natural or legal, private or public person who operates or controls the storage site or to whom decisive economic power over the technical functioning of the storage site has been delegated according to national legislation; This person may change from the storage preparations to the post-closure phase;

- **Substantial change**: a change which may have significant effects on the environment;

- **CO_2 stream**: a flow of substances that results from carbon dioxide capture processes;

- **CO_2 plume**: the dispersing volume of CO_2 in the geological formation;

- **Migration**: the movement of CO_2 within the storage complex;

- **Significant irregularity**: any irregularity in the injection or storage operations or in the condition of the site itself, which implies the risk of a leakage;

- **Corrective measures**: any measures taken to correct significant irregularities or to close leakages in order to prevent or minimise the release of CO_2 from the storage complex;

- **Closure of a CO_2 storage site**: the definite cessation of CO_2 injection into that storage site;

- **Post-closure**: the period after the closure of a storage site, including the period after the transfer of responsibility to the competent authority;

- **Transport network**: the network of pipelines, including associated booster stations, for the transport of CO_2 to the storage site.

Applicability conditions

3. This methodology applies to project activities that transport and store CO_2 produced from acid gas separation in natural gas processing in geological reservoirs.

4. The methodology is applicable under the following conditions:

- The generic requirements for site selection, monitoring, site development and liability (Annex A) are met, regardless of any legal framework for CCS operations that host country may or may not have in place. The source of CO_2 is the acid gas separation unit in natural gas processing facilities, both existing and/or new-to-build installations;

- The CO_2 is stored in saline aquifers or empty oil/gas fields; the methodology cannot be used when enhanced oil/gas recovery or ECBM is used
- The natural gas processing and CO_2 storage take place in the same country
- The geological formation has been characterised according to the procedures contained in Annex B and the site can be deemed to fulfil the criteria provided in Annex B
- An appropriate monitoring plan in accordance with Annex C

In addition, the applicability conditions included in the tools referred to above apply.

Finally, this methodology is only applicable if the application of the procedure to identify the baseline scenario results in that *continuation of the current situation* is the most plausible baseline scenario for existing installations, or *construction of a new gas processing facility without CCS* for new plants.

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

5. The **spatial extent** of the project boundary encompasses...

   a. The acid gas incinerator (only in the baseline scenario)

   b. CO_2 compression

   c. The generator of electricity for CO_2 compression for transport or injection

   d. The transportation of CO_2 to the storage site

   e. CO_2 injection facility

   f. The entire storage complex

6. The greenhouse gases included in or excluded from the project boundary are shown in Table 2.

Table 4: Emissions sources included in or excluded from the project boundary

Source		Gas	Included?	Justification / Explanation
Baseline	Acid gas incinerator	CO_2	Yes	This CO_2 is vented in the baseline and the only source of CO_2 emissions
		CH_4	No	Assumed to be negligible, and the slight fraction could be present in both baseline and project scenario

Project activity	Energy use in compression, transportation and injection	CO_2	Yes	Additional activities compared to the baseline such as compression, transportation and injection require energy generated by fossil fuels
		CH_4	No	Assumed to be negligible
	Seepage	CO_2	Yes	CO_2 may escape from separation unit, compression, transportation and storage
		CH_4	Yes	Possibly not negligible for oil/gas field storage

Identification of the baseline scenario

7. Project participants shall use the following steps to identify the baseline scenario:

Step 1: identify all credible alternatives to the project activity, at least including:

Alternative 1: the project activity implemented without the CDM

Alternative 2: utilisation of the separated CO_2 as a feedstock in industry or fertiliser in agriculture

Alternative 3: ending of natural gas production from the current reservoir

Alternative 4: continuation of the current situation.

Alternative 5: the project activity without the CDM at a later stage

Alternative 6: a new gas processing plant (without CO_2 capture and storage)

Step 2: Evaluation of the alternatives:

The alternatives identified in Step 1 can be analysed following the latest “Tool for the demonstration and assessment of additionality”.

Additionality: Please describe the procedure for demonstrating additionality

Additionality will be demonstrated using the latest tool for the demonstration and assessment of additionality. Guidance on the steps:

Step 1a. Determination of alternatives: see step 1 in the baseline determination

Step 1b. See step 2 of baseline determination

Step 2. Investment analysis: it can be demonstrated that without the CDM no economic incentive exists to the project activity, and thus that the CO_2 would be vented to the atmosphere. Option I of sub-step 2b (simple cost analysis) can be used, as the CDM project activity as well as the alternatives generate no financial or economic benefits other than CDM related income. It can be demonstrated that there is at least one alternative (i.e. continuation of the current situation for existing plants and for new plants construction of a new facility without CCS) less costly than the project activity.

Step 3. A barrier analysis by itself is insufficient to demonstrate additionality, and may only be used to support the investment analysis.

Step 4. Common practice analysis: analyse whether this is the first CCS activity in the host country. If there are already other CCS activities ongoing in the host country, follow substeps 4a and 4b.

Baseline emissions

CO_2 emissions in the baseline scenario originate from 1) venting of CO_2 after acid gas separation and 2) operation of the acid gas incinerator (if applicable)

The amount of CO_2 vented to the atmosphere in the baseline scenario in year y is obtained by multiplying the amount of acid gas injected in the pipeline by the fraction of CO_2 in the acid gas:

$BE_{vent} = C_{CO2,y} * Q_{in,\ y}$

Where:

$BE_{vent,y}$ is the amount of CO_2 vented to the atmosphere (tCO_2)
$C_{CO2,y}$ is the fraction of CO_2 in the acid gas (-)
$Q_{in,,y}$ is the amount of acid gas measured at the inlet of the pipeline (t)

CO_2 emissions from the operation of the acid gas processing facility are disregarded for conservativeness. Total baseline emissions are then equal to the vented CO_2 emissions:

$BE = BE_{vent}$

Project emissions

Project emissions include 1) emissions from the energy consumption during operation of the compression, transportation and injection equipment, 2) seepage in the process of compression transportation and injection, and 3) CO_2 and CH_4 (for storage in oil/gas reservoirs) seepage from the geological reservoir after injection.

Project emissions are estimated in the following steps:

Step 1a: Emission from booster installations along the CO_2 pipeline (PE_{boo})

Step 1b: Emissions from any seepage from the transport infrastructure ($PE_{fug,T,y}$)

Step 2a: Fugitive and vented emissions during injection of the CO_2 ($PE_{fug,I,,y}$)

Step 2b: Emissions from combustion installations generating electricity for the injection of the CO_2 ($PE_{com,I,,y}$)

Step 2c: Emissions from any seepage from the storage complex ($PE_{res,y}$)

Applying these steps, the total project emissions are:

$$PE_y = PE_{boo,T,y} + PE_{fug,T,y} + PE_{fug,I,y} + PE_{com,I,y} + PE_{res,y}$$

Where:

PE_y	are the project emissions in year *y* (tCO_2)
$PE_{boo,T,y}$	are emissions from booster installations along the transport infrastructure (tCO_2)
$PE_{fugT,,y}$	are fugitive emissions from the transport infrastructure (tCO_2)
$PE_{fugI,,y}$	are fugitive and vented emissions during injection (tCO_2)
$PE_{com,I,y}$	are emissions from combustion installations generating electricity for the injection of the CO_2 (tCO_2)
$PE_{res,y}$	is seepage from the storage complex (tCO_2)

Step 1a: Emissions from booster installations along the CO_2 pipeline

Combustion emission from fuel use in booster installations shall be calculated in accordance with the latest Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion.

Step 1b: Emissions from any seepage in the transport infrastructure

Emissions from transport will be calculated using a mass balance approach. While continuous measurements of CO_2 flows are surrounded by a measurement uncertainty, a conservative estimate needs to be made. Therefore, measured values for the CO_2 mass flow into and out of the pipeline will be corrected as follows:

$$PE_{T,y} = Q_{in,y} * (1+U_{pipe,95}) - Q_{out,y} * (1-U_{pipe,95})$$

With

$PE_{T,y}$	= project fugitive emissions from pipeline transport in year *y* [t/yr]
$Q_{in,y}$	= measured CO_2 flow from the capture installation to the pipeline [t/yr]
$Q_{out,y}$	= measured CO_2 flow out of pipeline to injection facility [t/yr]
$U_{pipe,95}$	= measurement uncertainty at a 95% confidence level [-/-]

Note: if mass balance leads to negative emissions, emissions will be assumed to be zero.

In the PDD the project developer shall elaborate a measurement campaign in order to estimate an emission factor for the pipeline network EF_{pipe} (tCO2/km/yr). Measurements will be conducted every year at representative locations of the transport network where leaks can be expected, e.g. at booster stations and pipeline joints. The emission factor shall be derived from the measurement results using statistical methods and taking into consideration the structure of the transport pipeline system, e.g. the number of booster stations, joints, etc. The development of the emission factor shall be documented and reported in detail, verified by an accredited DOE, and approved by the CDM EB.

Once the emission factor for the transport network has been approved, fugitive emissions may be calculated as:

$$PE_{T,y} = MIN(PE_{T,mb,y};PE_{T,ef,y})$$

With $PE_{T,mb,y}$ calculated as above and

$$PE_{T,ef,y} = L_y * EF_{pipe}$$

Where

$PE_{T,ef,y}$	=	project fugitive emissions from pipeline transport in year y estimated using the pipeline emission factor (t CO_2/yr)
L_y	=	length of the pipeline network in year y (km)
EF_{pipe}	=	emission factor for the pipeline network (tCO2/km/yr)

Step 2a: Emissions from combustion installations generating electricity for the injection of the CO_2

Emissions from fossil fuel combustion in installations generating power for CO_2 injection shall be calculated in accordance with the latest Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion.

Step 2b: Venting and fugitive emissions during injection

Fugitive and vented emissions during injection of the CO_2 will be measured by continuous flow measurement at a representative point as close as possible to the point of injection.

Step 2c: Emissions from any seepage from the storage complex

Any seepage from the storage complex will be estimated according to the monitoring plan developed by the operator. The monitoring plan shall be developed in accordance with the guidance provided in Annex C.

A conservative approach will be used to avoid the underestimation of emissions and thus ensuring the environmental integrity of the CDM. This is achieved by requiring reporting both the CO_2 and CH_4 emissions quantified plus an "uncertainty supplement", even though methane emissions are not likely to be significant. Based on this approach the calculation of the amount of CO_2-eq to be reported is as follows:

$PE_{res,,y} = (ES_{,res,y} + 23 * ES_{resCH4,y}) * (1 + U_{seep95})$

With:

$PE_{,res,y}$	= Reported project emissions from seepage from the reservoir in year *y*
$ES_{,res,,y}$	= Estimated CO_2 emissions from seepage from the storage complex using the available information from monitoring.
$ES_{,res,,y}$	= Estimated CH_4 emissions from seepage from the storage complex using the available information from monitoring.
23	= Global warming potential of CH_4 (tCO_2-eq/tCH_4)
U_{seep95}	= The level of uncertainty which is associated to the quantification approach used for the leakage in question, at a confidence level of 95%.

Besides avoiding the underestimation of emissions, the approach can be expected to have a supportive effect with regards to the development of quantification approaches with higher accuracy.

Leakage

8. There is no leakage involved in the methodology, as all CO_2 sources are included in the project boundary. The issue of the possibility that the CDM project may lead to prolonged technical lifetime and thereby increased production of the gas field is covered under the baseline & additionality assessments.

Emission reductions

9. Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y \quad \textbf{(3)}$$

Where:

ER_y	=	Emission reductions in year *y* (t CO_2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO_2e/yr)
PE_y	=	Project emissions in year *y* (t CO_2/yr)

Changes required for methodology implementation in 2nd and 3rd crediting periods

10. Additionality assessment needs to be carried out again, as local regulation and conditions may have changed which could impact the baseline and additionality of the project.

Data and parameters not monitored

11. In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Data / parameter:	
Data unit:	
Description:	
Source of data:	
Measurement procedures (if any):	
Any comment:	

III. MONITORING METHODOLOGY

12. All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Data and parameters monitored

Data / parameter:	$C_{CO2,y}$
Data unit	-
Description:	Fraction of CO_2 in acid gas injected in pipeline
Source of data:	Measurement by project participant
Measurement procedures (if any):	
Monitoring frequency	Regularly
QA/QC procedures:	
Any comment:	

Data / parameter:	Q_{in}
Data unit	t
Description:	Flow of acid gas measured at the inlet of the pipeline
Source of data:	Measurement by project participant

Data / parameter:	Q_{in}
Measurement procedures (if any):	
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$Q_{out,y}$
Data unit	t
Description:	CO_2 flow out of pipeline to injection facility in year *y*
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$PE_{fugI,,y}$
Data unit	t CO_2
Description:	fugitive and vented emissions during injection
Source of data:	
Measurement procedures (if any):	Continuous flow measurement
Monitoring frequency	Continuously
QA/QC procedures:	
Any comment:	

Data / parameter:	$ES_{,res,y}$
Data unit	t CO_2
Description:	Quantification of emissions from seepage from the storage complex using the available information from monitoring.
Source of data:	
Measurement procedures (if any):	Monitoring of seepage from the storage complex shall be in line with the stipulations in Annex C to this methodology.
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$ES_{resCH4,y}$
Data unit	t CH_4
Description:	Quantification of emissions from seepage from the storage complex using the available information from monitoring.
Source of data:	
Measurement procedures (if any):	Monitoring of seepage from the storage complex shall be in line with the stipulations in Annex C to this methodology.
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{seep,95}$
Data unit	-/-
Description:	The level of uncertainty which is associated to the quantification approach used for the seepage in question at a 95% confidence level
Source of data:	Expert judgement
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	$U_{pipe,95}$
Data unit	-/-
Description:	Uncertainty in continuous flow measurements of CO_2 in pipelines at a 95% confidence level
Source of data:	Expert judgement
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	L_y
Data unit	km
Description:	length of the pipeline network in year *y*
Source of data:	measurement by project participant
Measurement procedures (if any):	
Monitoring frequency	
QA/QC procedures:	
Any comment:	

Data / parameter:	EF_{pipe}
Data unit	emission factor for the pipeline network (tCO2/km/yr)
Description:	
Source of data:	determination through extensive measurement campaigns
Measurement procedures (if any):	
Monitoring frequency	annual
QA/QC procedures:	
Any comment:	

IV. REFERENCES AND ANY OTHER INFORMATION

Section D. Explanations / justifications to the proposed new baseline and monitoring methodology

Selected approach from paragraph 48 of the CDM modalities and procedures

13. 48b. As additionality will be based on an investment analysis, the baseline approach 'economically attractive course of action' is applicable to both existing and new build plants. In both cases the CDM is the only financial incentive to undertake the project.

Appendix IV Suggested annexes to CCS baseline methodologies

A: Generic requirements for site selection, monitoring, site development and liability
B: Criteria for the characterisation and assessment of storage sites
C: Criteria for establishing and updating the monitoring plan for the storage complex and injection facilities

ANNEX A: GENERIC REQUIREMENTS FOR SITE SELECTION, MONITORING, SITE DEVELOPMENT AND LIABILITY

(1) Site selection
A geological formation shall only be selected as a storage site, if under the proposed conditions of use [there is no significant risk of leakage / zero leakage is expected at a confidence level of 95%], and if no significant negative environmental or health impacts are likely to occur. The suitability of a geological formation for use as a storage site shall be determined through a characterisation and assessment of the potential storage complex and surrounding area pursuant to the criteria specified in Annex A.

(2) Monitoring
The operator shall carry out monitoring of the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment for the purpose of:
(a) comparison between the actual and modelled behaviour of CO_2 in the storage site;
(b) detecting migration of CO_2;
(c) detecting leakage of CO_2;
(d) detecting significant adverse effects for the surrounding environment, human populations, or users of the surrounding biosphere;
(e) assessing the effectiveness of any corrective measures taken;
(f) assessing whether the stored CO_2 will be completely contained for the indefinite future.

The monitoring shall be based on a monitoring plan designed by the operator pursuant to the requirements laid out in Annex B, submitted to and approved by the CDM-EB. The plan shall be updated pursuant to the requirements laid down in Annex B and in any case every five years to take account of technical developments. Updated plans shall be re-submitted for approval to the CDM-EB.

(3) Site development
Prior to starting injection the operator shall develop
- a contingency plan which will describe remediative measures in the event of leakage, including those for the remediation of leaky wellbores, and pressure reduction in the storage formation in the event of leakage along faults.
- a well abandonment plan including the choice of cements, intervals to be plugged, and subsequent quality control.
- a post-closure plan designed by the operator based on best practice and in accordance with the requirements laid down in Annex B. The (provisional) post-closure plan shall be updated as necessary, in particular in view of best practice, submitted to and approved by the CDM-EB.

(4) Liability
In case of seepage during crediting period and while operator still liable, or if the estimated amount of CO_2 released cannot be accurately determined, operator will need to surrender equivalent amounts of CERs to the CDM EB.

After a storage site has been closed, the operator remains responsible for maintenance, monitoring, control, reporting, and corrective measures, until the responsibility for the storage site is transferred to the competent authority. The operator shall also be responsible for sealing the storage site and removing the injection facilities. The post-closure requirements shall be fulfilled on the basis of the provisional post-closure plan submitted to and approved by the CDM-EB. In case of seepage during crediting period and while operator still liable, the operator will need to surrender equivalent amounts of CERs to CDM EB.

After site closure, the responsibility for the closed site, including all ensuing legal obligations, shall be transferred to the national authority controlling CCS operations, either on its own initiative or upon request from the operator, if and when all available evidence indicates that the stored CO_2 will be completely contained for the indefinite future, and after the site has been sealed and the injection facilities have been removed. To this end, the operator shall prepare a report documenting that this criterion has been met and submit it to the national authority on CCS for the latter to approve the transfer of responsibility.

The national authority shall inform the CDM-EB of all draft decisions of approval concerning liability transfer it has prepared, including the reports submitted by the operator and any other material taken into consideration by the responsible national authority when arriving at its conclusion. Within six months of their submission to the CDM-EB, the CDM-EB may issue an opinion on the draft decisions of approval. The national authority on CCS shall notify the final decision to the CDM-EB, stating the reasons if it deviates from the CDM EB opinion. Together with the decision of approval, the CDM-EB may communicate updated requirements for the sealing of the storage site and the removal of the injection facilities to the operator. The transfer of responsibility shall take place after the site has been sealed and the injection facilities have been removed.

After the transfer of responsibility, monitoring may cease. However, if any leakages or significant irregularities are identified, monitoring shall be reactivated by the host country as required to assess the scale of the problem and the effectiveness of corrective measures. In case of seepage after transfer of liability, the host country will need to surrender equivalent amounts of CERs, ERUs or AAUs to the CDM EB. There shall be no recovery of costs incurred from the former operator after the transfer of responsibility to the host country.

ANNEX B: CRITERIA FOR THE CHARACTERISATION AND ASSESSMENT OF STORAGE SITES

The characterisation and assessment of storage sites for CO_2 injection and storage for project activities under the CDM shall be carried out in four steps according to the following criteria. Derogations from one or more of these criteria are permitted so long as the capacity of the characterisation and assessment to enable the determinations is not affected.

Step 1: Data collection
Sufficient data shall be accumulated to construct a *volumetric and dynamic three-dimensional (3-D)-earth model f*or the storage site and storage complex including the caprock, and the surrounding area including the hydraulically connected areas. This data shall cover at least the following intrinsic complex characteristics:

(a) Reservoir geology and geophysics;
(b) Hydrogeology (in particular existence of potable ground water);
(c) Reservoir engineering (including volumetric calculations of pore volume for CO_2 injection and ultimate storage capacity, pressure and temperature conditions, pressure volume behaviour as a function of formation injectivity, cumulative injection rate and time);
(d) Geochemistry (dissolution rates, mineralisation rates);
(e) Geomechanics (permeability, fracture pressure);
(f) Seismicity (assessment of potential for induced earthquakes);
(g) Presence and condition of natural and man-made pathways which could provide leakage pathways;

The following characteristics of the complex vicinity shall be documented:

(h) Domains surrounding the storage complex that may be affected by the storage of CO_2 in the storage site;
(i) Population distribution in the region overlying the storage site;
(j) Proximity to valuable natural resources;
(k) Possible interactions with other activities (e.g. exploration, production and storage of hydrocarbons, geothermal use of aquifers);
(l) Proximity to the potential CO_2 source(s) (including estimates of the total potential mass of CO_2 economically available for storage).

Step 2: Computerised simulation of the storage complex
Using the data collected in Step 1, a *three-dimensional static geological earth model*, or a set of such models, of the candidate storage complex including the caprock and the hydraulically connected areas shall be built using computer reservoir simulators. The static geological earth model(s) shall characterise the complex in terms of:

(a) Geological structure of the physical trap;
(b) Geomechanical and geochemical properties of the reservoir;
(c) Presence of any faults or fractures and fault/fracture sealing;
(d) Overburden (caprock, seals, porous and permeable horizons);
(e) Areal and vertical extent of the storage formation;
(f) Pore space volume (including porosity distribution);
(g) Any other relevant characteristics.

The uncertainty associated with each of the parameters used to build the model shall be assessed by developing a range of scenarios for each parameter and calculating the appropriate confidence limits. Any uncertainty associated with the model itself shall also be assessed.

Step 3: Security, sensitivity and hazard characterisation
Step 3.1 Security characterisation
Security characterisation shall be based on dynamic modelling, comprising a variety of time-step simulations of CO_2 injection into the storage site using the three-dimensional static geological

earth model(s) in the computerised storage complex simulator constructed under Step 2. The following factors shall be considered:

(a) Possible injection rates and CO_2 properties;
(b) The efficacy of coupled process modelling (*i.e.* the way various single effects in the simulator(s) interact);
(c) Reactive processes (*i.e.* the way reactions of the injected CO_2 with *in situ* minerals feedback in the model);
(d) The reservoir simulator used (multiple simulators may be required in order to validate certain findings);
(e) Short and long-term simulations (to establish CO_2 fate and behaviour over decades and millennia including the solution velocity of CO_2 in water).

The dynamic modelling shall provide insight to:

(f) Pressure volume behaviour vs. time of the storage formation;
(g) Areal and vertical extent of CO_2 vs. time;
(h) The nature of CO_2 flow in the reservoir including phase behaviour;
(i) CO_2 trapping mechanisms and rates (including spill points and lateral and vertical seals);
(j) Secondary containment systems in the overall storage complex;
(k) Storage capacity and pressure gradients in the storage site;
(l) The risk of fracturing the storage formation(s) and caprock;
(m) The risk of CO_2 entry into the caprock (*e.g.*, due to exceedance of capillary entry pressure of the caprock or due to caprock degradation);
(n) The risk of leakage through abandoned or inadequately sealed wells;
(o) The rate of migration (in open-ended reservoirs);
(p) Fracture sealing rates;
(q) Changes in formation(s) fluid chemistry and subsequent reactions (*e.g.* pH change, mineral formation) and inclusion of reactive modelling to assess affects;
(r) Displacement of formation fluids.

Step 3.2 Sensitivity characterisation

Multiple simulations shall be undertaken to identify the sensitivity of the assessment to assumptions made about particular parameters. The simulations shall be based on altering parameters in the static geological earth model(s), and changing rate functions and assumptions in the dynamic modelling exercise. Any significant sensitivity shall be taken into account in the risk assessment.

Step 3.3 Hazard characterisation

Hazard characterisation shall be undertaken by characterising the potential for leakage from the storage complex, as established through dynamic modelling and security characterisation described above. This shall include consideration of *inter alia*:

(a) Potential leakage pathways;
(b) Potential magnitude of leakage events for identified leakage pathways (flux rates);
(c) Critical parameters affecting potential leakage (*e.g.* maximum reservoir pressure, maximum injection rate, sensitivity to various assumptions in the static geological Earth model(s) etc.);
(d) Secondary effects of storage of CO_2 including displaced formation fluids and new substances created by the storing of CO_2;
(e) Any other factors which could pose a hazard to human health or the environment (*e.g.* physical structures associated with the project);

The hazard characterisation shall cover a range of potential scenarios including scenarios that test the security of the storage complex to the extreme.

Step 4: Risk assessment

The risk assessment shall cover the range of scenarios developed under the hazard characterisation of Step 3 and shall comprise the following:

(a) *Exposure assessment* – based on the characteristics of the environment and distribution of human population above the storage complex, and the potential behaviour and fate of leaking CO_2 from potential pathways identified under Step 3;

(b) *Effects assessment* – based on the sensitivity of particular species, communities or habitats linked to potential leakage events identified under Step 3. Where relevant it shall include effects of exposure to elevated CO_2 concentrations in the biosphere (including soils, marine sediments and benthic waters (asphyxiation; hypercapnia) and reduced pH in those environments as a consequence of leaking CO_2). It shall also include an assessment of the effects of other substances that may be present in leaking CO_2 streams (either impurities present in the injection stream or new substances formed through storage of CO_2). These effects shall be considered at a range of temporal and spatial scales, and linked to a range of different magnitudes of leakage events.

(c) *Risk characterisation* – This shall comprise an assessment of the safety and integrity of the site in the short and long term, including an assessment of the risk of leakage under the proposed conditions of use, and of the worst-case environment and health impacts. The risk characterisation shall be conducted based on the hazard, exposure and effects assessment. It shall include an assessment of the sources of uncertainty.

ANNEX C: CRITERIA FOR ESTABLISHING AND UPDATING THE MONITORING PLAN FOR THE STORAGE COMPLEX AND INJECTION FACILITIES

1. Establishing and updating the monitoring plan

The monitoring plan for CO_2 storage and injection in project activities under the CDM shall be established and updated according to the following criteria:

1.1 Establishing the plan

The monitoring plan shall provide details of the monitoring to be deployed at the main stages of the project, including baseline, operational and post-closure monitoring. Baseline monitoring refers to any monitoring needed to estimate CO_2 emissions from the surface overlying the storage complex to the atmosphere. This is important in particular for on shore locations, where a background CO_2 flux is emitted, e.g. from the decomposition of organic matter in the soil.

The following shall be specified for each phase:

(a) Parameters monitored;
(b) Monitoring technology employed and justification for technology choice;
(c) Monitoring locations and spatial sampling rationale;
(d) Frequency of application and temporal sampling rationale.

The parameters to be monitored are identified so as to fulfil the purposes of monitoring. However, the plan shall in any case include continuous or intermittent monitoring of the following items:

(e) Fugitive emissions of CO_2 at the injection facility;
(f) CO_2 volumetric flow at injection wellheads;
(g) CO_2 pressure and temperature at injection wellheads (to determine mass flow);
(h) Chemical analysis of the injected material;
(i) Reservoir temperature and pressure (to determine CO_2 phase behaviour and state).

The choice of monitoring technology shall be based on best practice available at the time of design. The following options shall be considered and used as appropriate:

(j) technologies that can detect the presence, location and migration paths of CO_2 in the subsurface;
(k) technologies that provide information about pressure volume behaviour and areal/vertical saturation distribution of CO_2-plume by applying numerical 3-D-simulation to the 3-D-geological models of the storage formation established pursuant to Annex I;
(l) technologies that can provide a wide areal spread in order to capture information on any previously undetected potential leakage pathways across the areal dimensions of the complete storage complex and beyond, in the event of significant irregularities or migration of CO_2 out of the storage complex.

1.2 Updating the plan

The data collected from the monitoring shall be collated. The observed results shall be compared with the behaviour predicted in dynamic simulation of the 3-D-pressure-volume and saturation behaviour undertaken in the context of the security characterisation pursuant to Annex I Step 3.

Where there is a significant deviation between the observed and the predicted behaviour, the 3-D-model shall be recalibrated to reflect the observed behaviour. The recalibration shall be based on the data observations from the monitoring plan, and where necessary to provide confidence in the recalibration assumptions, additional data shall be obtained.

Steps 2 and 3 of Annex I shall be repeated using the recalibrated 3-D model(s) so as to generate new hazard scenarios and flux rates. The new scenarios shall be used to revise and update the risk assessment prepared under Annex I Step 4.

Where new CO_2 sources, pathways and flux rates are identified as a result of history matching and model recalibration, the monitoring plan shall be updated accordingly.

Post-closure monitoring shall be based on the information collected and modelled during the implementation of the monitoring plan referred to above under 1.2. It shall serve in particular to provide information required for the transfer of long-term liability.