baseline emissions overall reasonably provide for environmental integrity; the low or moderate levels of over-crediting that could occur under AM0028 and AM0034 could be compensated by significant under-crediting for newer plants applying ACM0019. Over time, the quality of CERs will increase due to the increased phase-in of ACM0019.

Table 4-3: Assessment of environmental integrity of nitric acid projects

Plant type	Metho-dology	Identified environmental integrity issues	2013-2020 CER potential	Potential for under- or over-crediting
Plants that started operation before 2006: 1st CP	AM0028 AM0034	• Perverse incentives not to adopt technologies that reduce the rate of N_2O formation • Risk of manipulation of the production process during the baseline campaign	73 million	Low or moderate over-crediting
Plants that started operation before 2006: 2nd and 3rd CP	ACM 0019	• Under-crediting for plants with higher N_2O formation rates than the IPCC range • Over-crediting for plants that adopt advanced primary catalyst technologies at faster rates	70 million	Neutral / Low over- or under-crediting
Newer plants or plants that did not use AM0028/ AM0034	ACM 0019	• None	32 million	Moderate to significant under-crediting

Sources: Authors' own compilation

4.4.5. Other issues

No other issues were identified.

4.4.6. Summary of findings

Nitric acid projects have a very high likelihood of additionality. Baseline emissions can be over- or under-credited; overall, they are likely to reasonably ensure environmental integrity for 2013-2020 CERs, with the average quality of CERs improving over time.

An important lesson learned from this project type is that the potential for technological innovation and perverse incentives was not sufficiently considered when approving the initial methodologies. For sectors that could undergo significant technological innovation, using historic data or measurement campaigns to establish a baseline for up to 21 years is debatable. The more recent ACM0019 methodology accounts for technological innovation by using an emission benchmark that declines over time.

Additio-nality	• Likely to be additional
Over-crediting	• Most recent methodologies lead to under-crediting • Overall, little risks of overall over-crediting
Other issues	• None

4.4.7. Recommendations for reform of CDM rules

No recommendations.

4.5. Wind power

4.5.1. Overview

CDM wind power projects mainly use four methodologies.[49] The vast majority of projects (more than 99% of all CDM wind projects) feed electricity into the grid.[50]

According to the UNEP DTU (2014), by the end of 2013, an overall wind power capacity of 111 GW had been installed by projects using the CDM. The main contributors to this overall capacity are China (83 GW), India (10 GW), Mexico and Brazil (both 4 GW). The other 36 countries with CDM wind power projects account for 10 GW of installed capacity in total.

Figure 4-2, Figure 4-3 and Figure 4-4 illustrate the development of wind power capacity and the use of the CDM in China, India and Brazil.[51] In China, installation of wind power capacity accelerated from 2005 onwards. A comparison of the total wind power capacity installed and the capacity installed by projects using the CDM[52] over the 2005 to 2012 period (Figure 4-2) shows that CDM projects accounted for about 90% of the total cumulated installed capacity as of 2012 (about 75 GW). In the case of India (Figure 4-3), installed capacity increased significantly between 2005 and 2012 from 1.4 GW in 2005 to more than 15 GW in 2012. CDM projects accounted for about half (51%) of the total cumulated capacity installed as of 2012. In the case of Brazil (Figure 4-4), the total cumulated installed capacity as of 2012 was much smaller (2.5 GW). The share of CDM projects in cumulative capacity was 43% as of 2012.

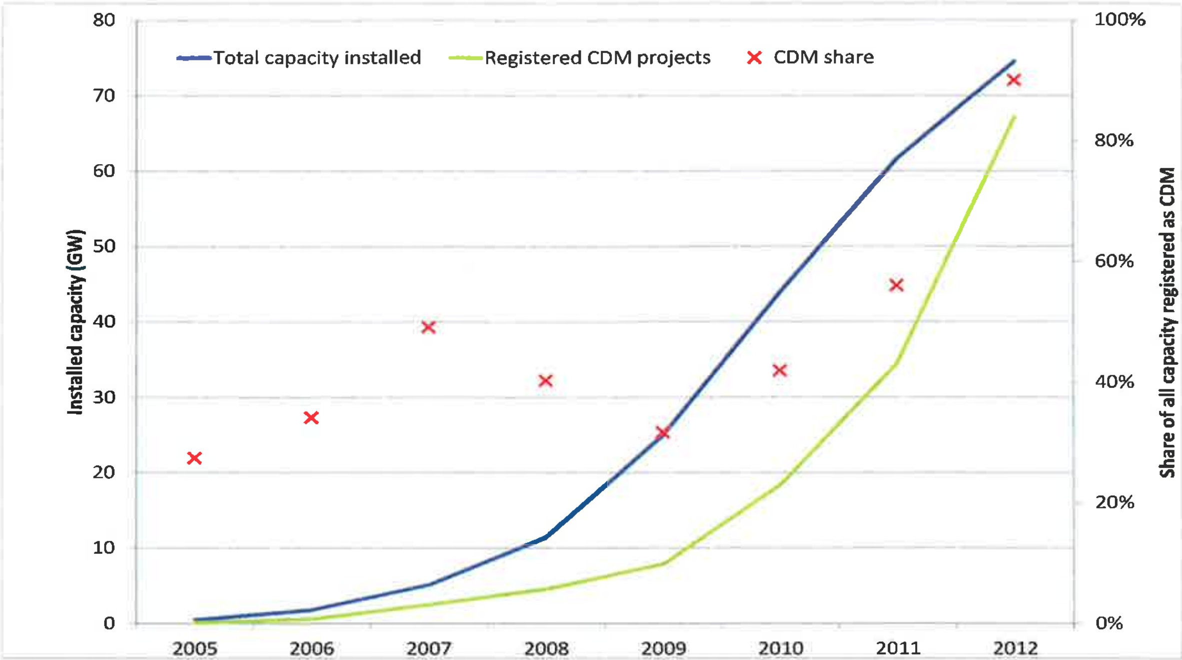
49 ACM0002, AMS-I.A, AMS-I.D, AMS-I.F.

50 ACM0002 (large scale), AMS-I.D (small scale).

51 China, India and Brazil are selected for the graphs in order to ensure comparability across chapters on renewable power generation since they are important CDM countries for hydropower and biomass power, too.

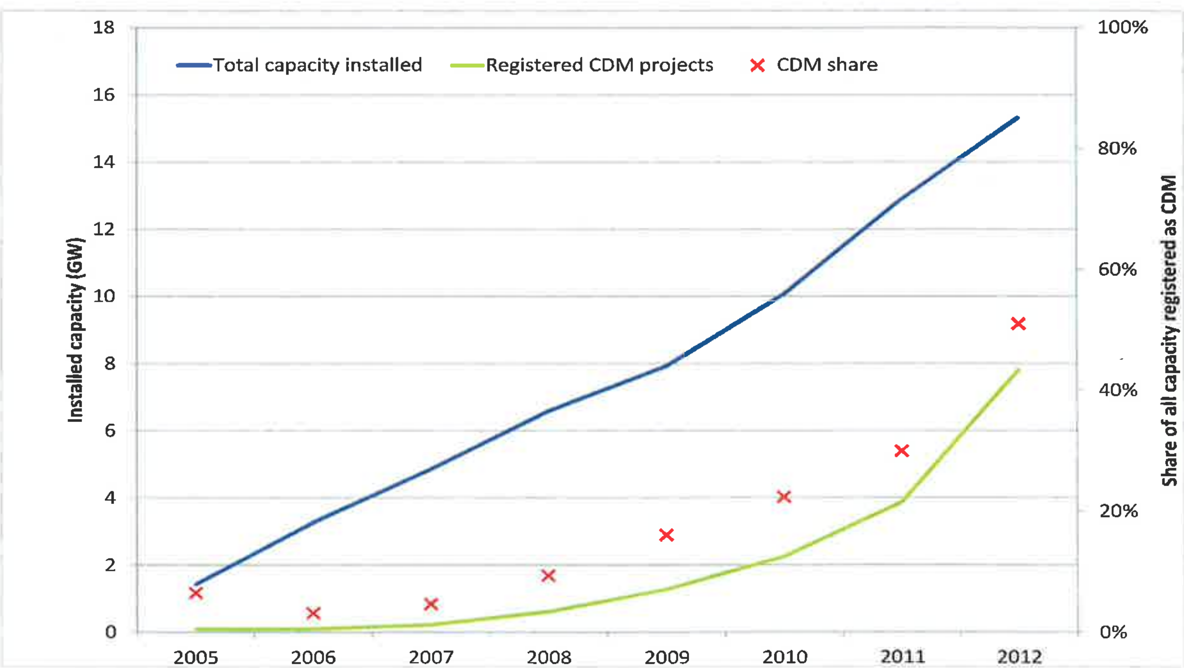
52 The total installed capacity between 2005 and 2012 is taken from the World Wind Energy Association statistics (WWEA 2015) and accumulated across the years. The installed capacity of projects using the CDM is taken from UNEP DTU (2014) and accumulated, too. The installation year is taken as the starting date of the crediting period. Cumulative values were used to illustrate the contribution of the CDM since annual values are misleading due to potential differences between the year of construction and the year in which the crediting period starts. Therefore, cumulative values provide a better picture of the general trend of the CDM share in total capacity installed.

Figure 4-2: Total cumulated wind power capacity installed in China between 2005 and 2012



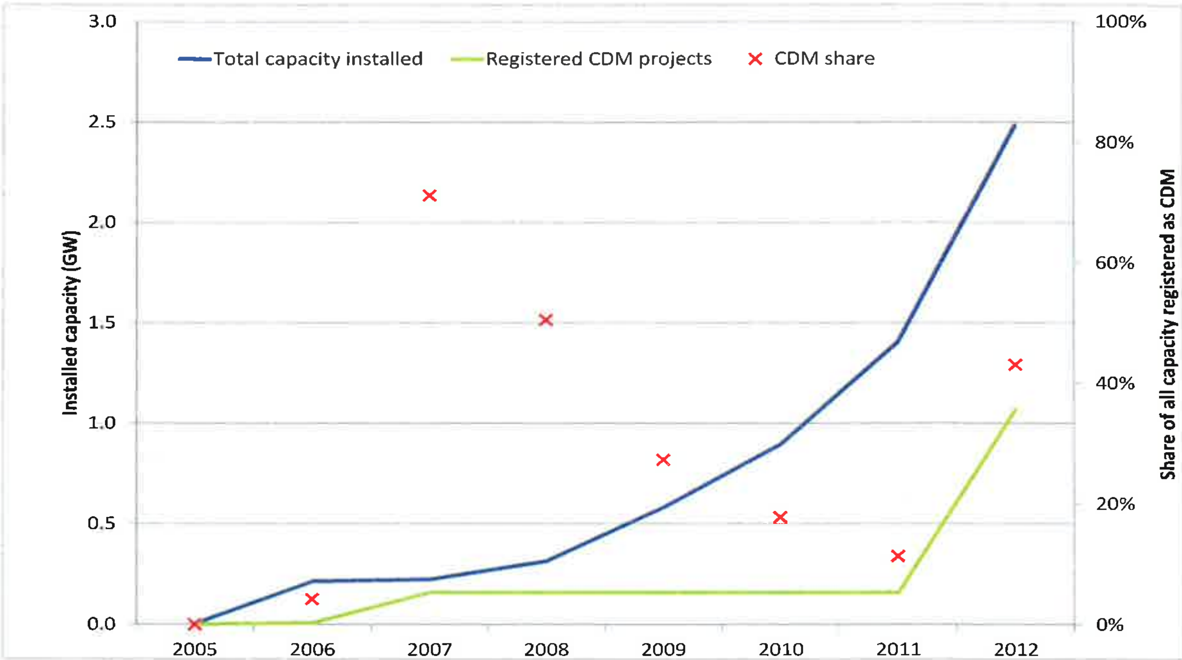
Sources: UNEP DTU 2014, WWEA 2015, authors' own calculations

Figure 4-3: Total cumulated wind power capacity installed in India between 2005 and 2012



Sources: UNEP DTU 2014, WWEA 2015, authors' own calculations

Figure 4-4: Total cumulated wind power capacity installed in Brazil between 2005 and 2012



Sources: UNEP DTU 2014, WWEA 2015, authors' own calculations

4.5.2. Potential CER volume

According to our own estimates, registered CDM wind power projects have the potential to issue 3.5 billion CERs by the end of their respective crediting periods, of which 1.4 billion CERs fall in the period from 2013 to 2020 (Table 2-1). CERs from wind power account for about one quarter of the total CER issuance potential.

4.5.3. Additionality

Large-scale wind power projects apply the methodology ACM0002 which requires using the "Tool for the demonstration and assessment of additionality" to demonstrate additionality.[53] In this tool, the investment analysis is one of the approaches for demonstrating additionality. Most CDM wind power projects use investment analysis. The tool for small-scale projects ("Methodological tool. Demonstration of additionality of small-scale project activities"[54]) requires "an explanation to show that the project activity would not have occurred anyway due [...] to barriers", among which one of the most important barriers is the so-called 'investment barrier', which generally features a similar rationale as for the investment analysis of large-scale projects.

Section 3.2 describes the general criticism associated with the investment analysis and Section 2.4 assesses for different project types the impact of CER revenues on their economic performance. According to these analyzes, for wind power projects, CER revenues lead to an increase in the internal rate of return (IRR) of two to three percentage points. An analysis by the World Bank finds that "the incremental IRR from future carbon revenues in renewable energy projects, taking the World Bank's projects as an example, is quite low" (Carbon Finance at the World Bank 2010). In

53 Current version 07.0.0 (EB 70, Annex 8).
54 Current version 10.0 (EB 83, Annex 14).

this analysis, the incremental IRR for renewable energy projects amounts to 1.7% for a purchase period of 10 years and an assumed CER price of $10/t. Another analysis finds that "wind, hydro and biomass projects experience only a small increase in profitability through CDM" and that "the change in profitability caused by regional variables is greater than the CDM's impact for wind, hydro and biomass"[55] (Schneider, M. et al. 2010). From these analyzes, it can be concluded that the CDM impact in the profitability of wind power plants is generally relatively low and that the 'signal' provided by the CDM is usually much smaller than the 'noise' of national and regional variations in other parameters.

In addition, many countries have set up domestic support schemes in order to promote the increased use of renewables. Spalding-Fecher et al. (2012) provide an overview of several important support incentives for renewable energy generation in major CDM countries (such as China and India) and find "that national policies on electricity tariffs for renewable power could be a more important driver of the viability of wind, hydropower and biomass projects than the CDM is." In the case of wind power plants in China, Bogner & Schneider (2011) point out that "the wind power boom in China is mainly driven by favourable policies and not by the CDM" and that "the majority of projects would most likely have been implemented without the CDM". Liu (2014) elaborates on the links between the CDM and national policy in the case of wind power development in China. He finds that a decreasing national feed-in tariff can increase "CDM-supported installed capacity because more projects may comply with CDM requirements as their financial returns remain below the predefined additionality threshold", which indicates that there is a clear interference between national policy development and the additionality requirements of the CDM. He also finds that "the reduction of technology costs combined with an increasing local manufacturing capacity has paved the way for a scaled-up deployment of wind capacity" (ibid.), which indicates that other factors than the CDM were important in the significant growth of wind power in China. However, he concludes that the CDM "effect on wind technology diffusion [...] is more than twice as high as that of technology cost and industrial policy" (ibid.). He also finds that "while domestic policies must be the engine for large-scale clean energy investments in developing countries, the international carbon offset policy can help that engine run faster, but only if the engine is running" (ibid.). For India, in comparing wind power projects registered under the CDM with those without such support, Dechezleprêtre et al. (2014) find that, "all other things being equal, CDM wind farms tend to be larger, to benefit from higher feed-in-tariffs, and to be located in windier areas, three factors which increase profitability." According to this analysis, there is "serious evidence of non-additionality of the CDM" (ibid.). He & Morse (2013) find that "Chinese power prices are either tightly controlled by state regulators or are distorted by the presence of large state owned enterprises (SOEs)" and this leads to the conclusion that "IRR-based additionality tests are fundamentally incompatible with state-controlled power pricing regime".

Furthermore, investment costs for wind power generators have decreased significantly in recent years, which results in wind power featuring (in many cases) competitive levelited costs of electricity in comparison to new fossil-fired power plants (IRENA 2015; ISE 2013). In addition, IRENA (2015) also shows that specific investments costs for onshore wind power plants are significantly lower in China and India than in OECD and 'rest of the world' countries. Similarly, Schmidt (2014) finds that the risk associated with low-carbon investment is higher in some parts of the world than in others. In an analysis for industrialised and low-income countries (using typical values for costs of capital in these countries), he finds that due to the higher cost of capital in low-income countries, levelized costs of electricity for onshore wind power plants could be as much as 46% higher than in low-risk countries. Altogether, the available information indicates that the profitability of wind power

[55] In this analysis, regional factors are the electricity tariff, the load factor and the discount rate.

plants has generally improved. However, there is also a significant dependence of the profitability on regional circumstances.

Overall, due to the limited impact of CER revenues on the profitability of wind power plants, the widespread introduction of domestic support schemes and the significant decrease of wind power costs, we consider the additionality of wind power projects as generally questionable in the context of the CDM, at least for countries with support schemes, low investment costs for wind power and low investment risks.

4.5.4. Baseline emissions

Baseline emissions of CDM wind power projects feeding electricity into the grid include CO_2 emissions from fossil-fired power plants that are displaced due to the project activity. In most cases, the corresponding baseline CO_2 emission factor is estimated using the "Tool to calculate the emission factor of an electricity system"[56] (Box 4-1).

Box 4-1: The grid emission factor tool

The grid emission factor is calculated as the "combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM)".[57] According to the tool, "the operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed CDM project activity. The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected by the proposed CDM project activity."

In the tool, several approaches for estimating the combined margin are presented, depending on the specific conditions of the project and data available. In general, the approach of using a combination of OM and BM, depending on the type of project, is appropriate. It suitably reflects that CDM projects could have short-term impacts on the dispatch of power plants and long-term impacts on the power plants built, and different weights for the OM and the BM can be applied (depending on the crediting period and on whether it relates to a project using intermittent or non-intermittent sources), which also can be considered appropriate. A number of specific issues arise from the tool:

In many cases, so-called low-cost and must-run power plants are not considered in the calculation of the CO_2 grid emission factor, which may lead to higher baseline emissions per amount of electricity produced. Neglecting low-cost/must-run power plants, such as renewables or nuclear power, may generally be considered adequate for the estimation of the operating margin (since low-cost/must-run power plants can be expected to be running irrespective of any other power plant in the system). However, an increasing share of renewables (e.g. wind or solar) in the system may lead to a situation in which renewable power generation is at the margin in some hours, i.e. an additional kilowatt hour of renewable electricity does not displace fossil fuels in that hour. In some countries, for example, wind power plants are switched off when electricity supply exceeds demand in order to ensure a stable electricity system. Furthermore, 'low-cost' power plants are not clearly defined and some of them may be dispatchable (such as biomass). Overall, the provision of excluding low-cost/must-run power plants may lead to an overestimation of baseline emissions.[58]

56 Current version 04.0 (EB 75, Annex 15).
57 AMS-I.D, version 17 (EB 61, Annex 17).
58 It has to be noted, however, that in the case the country has a large share of low-cost/must-run power plants (more than 50%), e.g. hydro, the simple adjusted operating margin has to be used. In that case, whenever hydro electricity provides sufficient electricity to cover the load demand in a certain hour, this hour is counted as not emitting. This leads to lower baseline emission factors overall than the simple operating margin. The implicit assumption is that water would be spilled in that hour if additional (i.e. CDM) power

Also, both the operating and the build margin approaches are based on historical production and installation data if the option of determining the grid emission factor at the validation stage (ex-ante) is chosen. The resulting baseline grid emission factor is then kept constant throughout the crediting period and only updated at the renewal of the crediting period. This approach does not reflect the general trend towards an increasing share of less-emitting power sources in the electricity mix of many countries. It is oriented to past power systems (backward-looking perspective) rather than to the actual power systems during the crediting period with a higher penetration of renewables (forward-looking perspective). This is especially problematic in countries with a rapidly changing or expanding electricity system. In countries with a growing share of renewable energy capacities, this approach may lead to an overestimation of baseline emissions. However, due to the long-lived capital stock in the electricity sector, changes of the grid emission factor are only gradual (i.e. take several years) in case the power system as a whole is not expanding fast. An advantage of using historical data is that it relies on observed and objective information, whereas scenarios for the future development of the power system may be prone to uncertainty and use of unrealistic assumptions.[59] Therefore, the determination of the grid emission factor based on historical data is not considered problematic per se but should be adjusted to account for trends in the sector.[60] Another option for determining the grid emission factor is the ex-post determination during monitoring. This approach is certainly adequate since it reflects the current state of the power sector.

With regard to the build margin, CDM projects are generally excluded from the estimation of the CO_2 emission factor. CDM projects only need to be gradually included if they comprise a significant share of power plants built in the last ten years. This approach can generally be considered adequate, especially in countries with an already significant share of renewable electricity generation or promotional policies for renewables in place, in which case a neglect of CDM projects in the build margin would not be a plausible representation of what would have happened in the absence of the project. This approach therefore addresses the risk of over-estimating baseline emissions in countries with a large share of CDM projects.

The quality of input data in calculating the grid emission factor is also important. In analysing grid emission factors provided by different DNAs, Michaelowa (2011) finds "that most of the documents provided by the DNAs do not allow an external observer to judge whether the data has been collected correctly" and that "there are clear indications that the grid emission factors, as well as the coal power plant benchmarks, have been overestimated both in China and India." In some countries, the governments established grid emission factors, and DOEs apparently used the values without validating whether they comply with the methodological requirements under the CDM. In order to address this issue, Michaelowa (2011) recommends, inter alia, an "independent validation of grid EF". Recently, few grid emission factors are submitted as standardized baselines which ensures independent validation by a DOE or the UNFCCC secretariat.

Furthermore, the tool provides several default values for parameters such as the electric efficiency of power plants. The values provided can be considered quite conservative, i.e. they assume rather high electric efficiencies. For those countries using the default values, this may lead to an under-estimation of baseline emissions.

generation is available. However, some countries do not only have run-of-river hydro power plants (for which case, the assumption of spilling water may be reasonable), but water may also be stored in large reservoirs and thus used at a later stage. In this regard, the estimation of baseline grid emissions for countries with a large share of low-cost/must-run power plants can be considered conservative, i.e. tending to under-estimate baseline emissions. However, it has to be noted that less than 5% of CDM projects used this approach for estimating the grid emission factor.

59 E.g. assuming that there would be a significant increase of coal-fired power generation without straightforward evidence.

60 For example, trends in a changing composition of the electricity grid or the grid emission factor observed in recent years could be considered and extrapolated for future years. Similar approaches are used in a number of other CDM methodologies.

The overall emissions impact of wind power plants also depends on other factors. Firstly, the upstream emissions from wind power, such as for construction, are relatively low (about 10 g CO_2e/kWh (IPCC 2014)); for most countries they are likely to be lower than upstream emissions from fossil fuel use displaced in grid power plants. Ignoring upstream emissions is therefore a conservative assumption. Secondly, an increasing uptake of wind power plants due to the CDM may lead to decreasing costs for wind power generation, which in turn could contribute to a higher uptake of wind power. This positive spillover effect is, however, difficult to estimate, in particular with regard to any emissions outcome. Thirdly, the length of the crediting period may lead to under-crediting if wind power plants are operated longer than the crediting periods.[61] However, many wind power plants are expected to operate for about 20 years and about three quarter of wind power projects have selected a renewable crediting period of up to 21 years. Further aspects of potential over- and underestimation of baseline emissions are described in (Erickson et al. 2014).

Overall, we conclude that the current approach for estimating emission reductions from CDM wind projects is largely suitable. Methodological assumptions lead to both over- and under-estimation of emission reductions but can be considered appropriate for estimating baseline emissions of CDM wind projects.

4.5.5. Other issues

No other issues were identified.

4.5.6. Summary of findings

Additio-nality	• **CER revenue** has only a **limited impact** on profitability of wind power plants • **Support schemes** often exist and are a main driver for wind power development • **Investment costs have decreased significantly in recent years,** making wind power in some cases **competitive with fossil generation (LCOE)** • Wind power is already **widely used** in large CDM countries (e.g. China, India)
Over-crediting	• Methodological assumptions may lead to both over- and under-crediting; no clear-cut conclusion on whether over- or under-crediting occurs overall
Other issues	• None

4.5.7. Recommendations for reform of CDM rules

Due to our finding of an overall questionable additionality of wind power projects, we recommend that this project type is generally no longer eligible for new projects under the CDM. As an exception to this rule, countries with significant technological and cost barriers[62] may be allowed to further use the CDM for implementing wind power plants.

With regard to the estimation of baseline emissions, we recommend the following:

- The CDM EB should ensure that grid emission factors are always verified by designated operational entities (DOEs);

[61] For a discussion of the effects of the crediting period, refer to Section 3.5.

[62] Such as transaction costs, e.g. due to the non-availability of technical knowledge in the country, or risk premiums in low-income countries. Least-developed countries could, for instance, be included in the list of eligible countries. Furthermore, the market share of wind power could be used to establish eligibility since it could be considered an indicator for barriers in the country.

- The provisions for low-cost/must-run plants should be reviewed, including a clear definition of such plants and provisions which ensure that such plants are included in the operating margin if they are at the margin of the dispatch at any time;

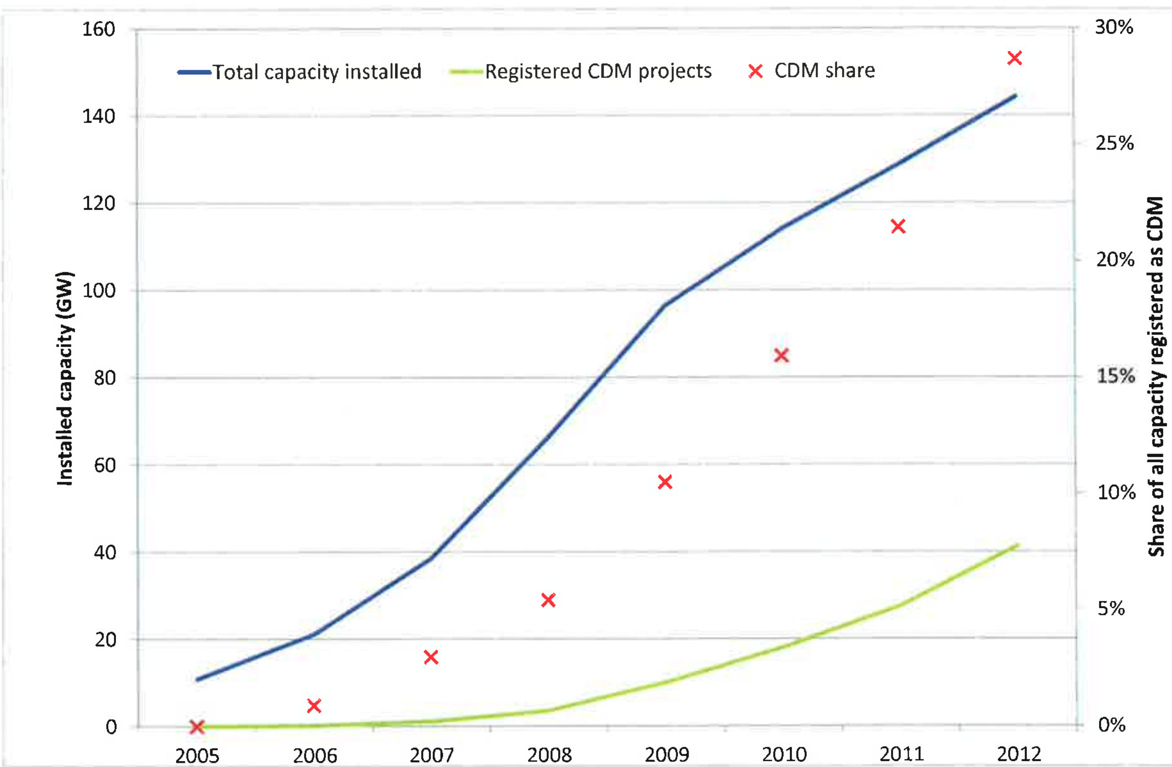
- The grid emission factor tool should be revised to reflect trends in the composition of the power sector over time.

4.6. Hydropower

4.6.1. Overview

CDM hydropower projects mainly use two methodologies.[63] According to the UNEP DTU (2014), by the end of 2013, an overall hydropower capacity of 92 GW had been installed by projects using the CDM. The main contributors to this overall capacity are China (58 GW), Brazil (12 GW), followed by Vietnam and India (6 GW each). The other 44 countries with CDM hydropower projects account for 11 GW of installed capacity in total.

Figure 4-5: Total cumulated hydropower capacity installed in China between 2005 and 2012



Sources: UNEP DTU 2014, Platts 2014, authors' own calculations

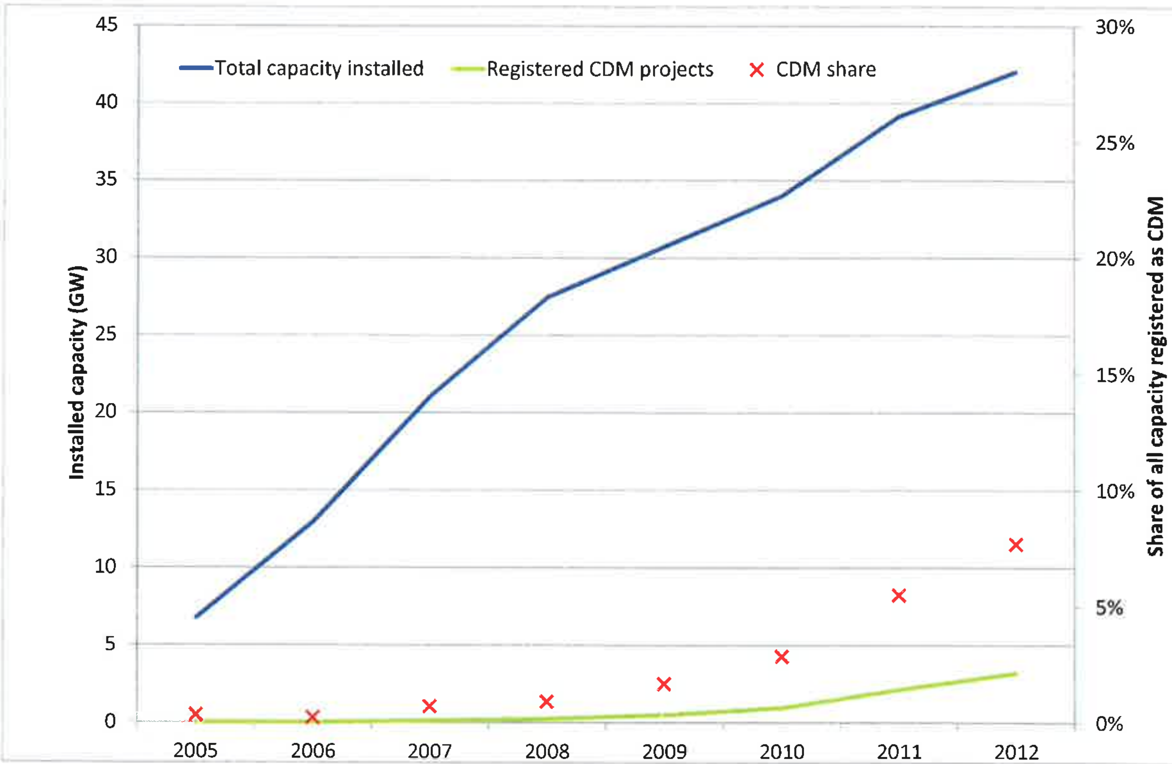
As for wind power, Figure 4-5, Figure 4-6 and Figure 4-7[64] illustrate the development of hydropower capacity and the use of the CDM in China, India and Brazil. In all three countries, hydropower has played an important role for many decades. Significant capacity has been installed without the CDM. Hydropower may therefore be considered common practice in all three countries.

[63] ACM0002, AMS-I.D.
[64] Cf. footnote 51.

In China, the cumulated installed capacity in 1990 amounted to approx. 25 GW. A comparison of total hydro capacity installed and the capacity installed by projects using the CDM[65] over the 2005-2012 period (Figure 4-5) shows that there were no CDM projects until 2005, even though capacity additions in that year amounted to 11 GW. As of 2012, the share of CDM projects was 29% of total installed capacity.

In the case of India (Figure 4-6), the cumulated installed capacity in 1990 amounted to approx. 19 GW. Almost 7 GW of capacity was added in 2005 alone, with the CDM covering only a negligible share. After the introduction of the CDM, only a small share of hydropower projects used the CDM, with the CDM accounting for about 8% of total cumulated installed capacity[66] as of 2012.

Figure 4-6: Total cumulated hydropower capacity installed in India between 2005 and 2012



Sources: UNEP DTU 2014, Platts 2014 authors' own calculations

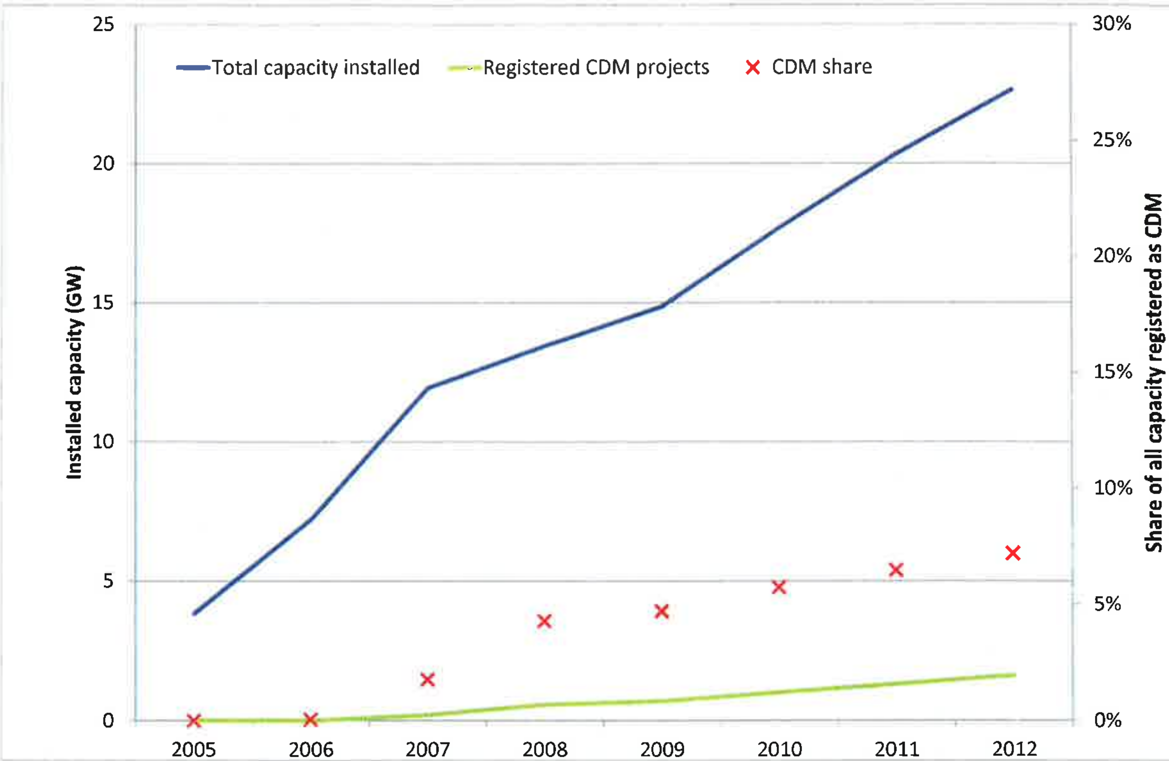
In the case of Brazil (Figure 4-7), the cumulated installed capacity in 1990 amounted to approx. 53 GW. Almost 4 GW of capacity was added in 2005, with no CDM projects being registered in that year. Even after the introduction of the CDM, only a small share of hydropower projects used the CDM (approx. 7% of total cumulated installed capacity[67] as of 2012).

[65] The total installed capacity between 2005 and 2012 is taken from the Platts database and accumulated across the years. The installed capacity of projects using the CDM is taken from the UNEP DTU (2014) and accumulated, too. The installation year is taken as the starting date of the crediting period. See Section 4.5 for the rationale of using cumulative data.

[66] Between 2005 and 2012.

[67] Between 2005 and 2012.

Figure 4-7: Total cumulated hydropower capacity installed in Brazil between 2005 and 2012



Sources: UNEP DTU 2014, Platts 2014, authors' own calculations

4.6.2. Potential CER volume

According to our own estimates, registered CDM hydropower projects have the potential to issue 4.2 billion CERs by the end of their respective crediting periods, of which 1.7 billion CERs fall in the 2013-2020 period (Table 2-1). CERs from hydropower account for approx. 30% of the total CER issuance potential.

4.6.3. Additionality

Generally, the same methodologies and additionality rules apply as for wind power (Section 4.5.2). Hydropower CDM projects primarily use investment analysis to demonstrate additionality.

The analysis in Section 4.6.1 demonstrates that hydropower plants have been constructed for a long time in many countries, which suggests that the technology may be regarded as common practice in many countries. In many cases, especially large hydropower plants were established without subsidies, which is demonstrated by the uptake of hydropower many years ago (Section 4.6.1). In the case of small hydropower (SHP) plants in China, Bogner & Schneider (2011) find that "apparently, smaller SHP plants face stronger barriers despite the government's commitment to SHP development" and that "an especially remote location, an inappropriate feed-in tariff or banks that deny loans can be possible barriers". Therefore, they conclude that "the CDM may have played a certain role for some SHP project developments" (ibid.). However, they argue that "investment in SHP stations between 20 and 50 MW appear more feasible without the CDM" (ibid.). Moreover, according to their analysis "medium and large hydropower has witnessed considerable growth a long time before the CDM even existed, which makes it difficult to justify that new projects can only be implemented with the help of the CDM. In conclusion, our analysis suggests that the CDM is for most projects not an important factor for investment decisions in the medium and large hydropower plants. It appears likely that most projects would have been implemented in any case, i.e. without the CDM".

The impact of CER revenues on profitability is, at three to four percentage points, somewhat larger than for wind power (Section 2.4), mostly due to a higher plant utilization than for wind power. However, the increase in profitability due to CDM revenues is still relatively small compared to other project types[68]. Also, in many cases, hydropower generally features competitive levelized costs of electricity in comparison to new fossil-fired power plants (IRENA 2015; ISE 2013).

Overall, due to the fact that hydropower is common practice in many countries, the limited impact of CER revenues on the profitability of hydropower plants and the competitiveness of hydropower with fossil electricity generation in many cases, we consider additionality of hydropower projects as questionable in the context of the CDM, especially for large hydropower.

4.6.4. Baseline emissions

Hydropower projects largely use the same methodological approaches for baseline emissions as wind power plants, and hence the same conclusions apply with regard to different aspects of over- or under-crediting. Few differences should be noted with regard to the emission impacts: Hydropower projects have, on average, somewhat higher upstream emissions for their construction (approx. 20 g CO_2e/kWh related to the "infrastructure & supply chain emissions" according to (IPCC 2014)), which, however, are still lower than typical upstream emissions from fossil use in the baseline. Thus, ignoring upstream emissions is still conservative. More importantly, the lifetime of hydropower can be significantly longer than the maximum crediting period under the CDM (21 years), which adds to the conservatism of the estimation of emission reductions for hydropower plants. In this regard, over the plants' lifetime, overall emission reductions may be rather under-estimated than over-estimated.

4.6.5. Other issues

In addition to baseline emissions, project CH_4 emissions ensuing from hydro reservoirs are considered under the CDM. The ACM0002 methodology uses the power density, which is defined as the installed hydro capacity divided by the reservoir surface, as an indicator of whether CH_4 emissions from reservoirs need to be considered. CDM projects with a power density below 4 W / m^2 are not eligible and projects with a power density between 4 and 10 W / m^2 have to estimate methane emissions, using a default emission factor of 90 g CO_2e/kWh. According to (IPCC 2014), methane emissions from "currently commercially available technologies" amount to 88 g CO_2e/kWh, however, the bandwidth is quite large. However, according to (Fearnside 2015), the default emission factor of 90 g CO_2e/kWh refers "only to bubbling and diffusion from the reservoir surface and" is an underestimate "of hydropower impact because these values ignore the main sources of methane release: the turbines and spillways". Overall, he finds that "tropical hydroelectric dams themselves emit more greenhouse gases than are recognized in CDM procedures". It can therefore be concluded that the current methodological rules under the CDM may lead to a potential underestimation of methane emissions from hydropower.

[68] It has to be noted, however, that the range of operating hours and investment costs of hydro power plants depends quite strongly on plant-specific conditions, for which reason the contribution of the CDM to overall profitability may be higher in some cases and lower in others.

4.6.6. Summary of findings

Additio-nality	• **Common practice** in many countries • **CERs** have only a **moderate impact** on profitability • In many cases **competitive with fossil generation** (LCOE)
Over-crediting	• Methodological assumptions may lead to both over- and under-crediting; over the lifetime of the project, emission reductions are likely to be underestimated
Other issues	• Potentially significant **methane emissions** from reservoirs which may not be fully reflected by CDM methodologies

4.6.7. Recommendations for reform of CDM rules

We recommend excluding large scale hydropower projects from being eligible under the CDM, due to the overall questionable additionality. A similar recommendation is made by (Erickson et al. 2014), who, in an analysis of the net mitigation impact of the CDM conclude "that excluding large scale power supply projects from the CDM could help increase the net mitigation impact of the CDM, as well as steer investment towards projects that are truly dependent on CER revenues". We recommend that small-scale hydropower projects with significant technological or cost barriers[69] may be allowed under the CDM.

With regard to the estimation of baseline emissions, our recommendations for wind power plants (Section 4.5.7) also apply here. In addition, the provisions with regard to the estimation of methane emission from hydropower should be revised to address the potentially significant magnitude of these emissions.

4.7. Biomass power

4.7.1. Overview

CDM biomass power projects mainly use four methodologies.[70] According to the UNEP DTU (2014), by the end of 2013, an overall biomass energy[71] capacity of 8.5 GW was installed by projects using the CDM. The main contributors to this overall capacity are China (3.7 GW) and India (2.1 GW), followed by Brazil (0.9 GW). The other 36 countries with CDM biomass projects account for 1.8 GW of installed capacity in total.

Generally, data availability is not sufficient to judge the magnitude of biomass capacity installed prior to the introduction of the CDM. Moreover, due to inconsistencies in the data, no meaningful comparisons can be made between projects installed with and without the use of the CDM.

4.7.2. Potential CER volume

According to our own estimates, all registered CDM biomass power projects have the potential to issue 0.36 billion CERs by the end of their respective crediting periods, of which 0.16 billion CERs fall in the period from 2013 to 2020 (Table 2-1). CERs from biomass power account for about 3% of the total CER issuance potential.

69 The criteria need to be further specified. See also footnote 62.
70 ACM0006, AM0015, AMS-I.C, AMS-I.D. It has to be noted, however, that the AM0015 methodology was only used for CDM projects registered in the early phase of the CDM.
71 Including different energy forms from biogenic sources.

4.7.3. Additionality

For large-scale projects (according to ACM0006), the identification of the baseline scenario and the demonstration of additionality are conducted in parallel.[72]

With regard to the investment analysis, due to the diversity of project types, no overall conclusions can be drawn. Also, analysis available in the literature is quite limited, in contrast to wind and hydropower. On average, the impact of CER revenues on the profitability of projects is with about eight percentage points considerably larger than for wind or hydropower plants, making additionality claims more plausible (Section 2.4). The profitability of projects without CER revenues is, with an average IRR of approx. 5%, also lower than for wind (approx. 7%) and hydro (approx. 8%). The higher impact of the CDM is mostly due to the claiming of avoided methane emissions in many projects, which significantly improves the profitability of CDM biomass projects.

The investment analysis, which is applied by many projects, involves considerable uncertainty due to the variability of the biomass price, which strongly affects the profitability of biomass plants. In addition, many countries have set up domestic support schemes in order to promote the increased use of renewables, including ones for biomass power generation. In addition, biomass power is not a completely new technology, but is rather based on the technology of thermal power plants in general and has been used extensively in some industries and countries before (e.g. in the sugar cane industry in Brazil), which indicates that the technology has been profitable in the past in some instances. This is underpinned by the fact that biomass power features competitive levelized costs of electricity in comparison to new fossil-fired power plants (IRENA 2015; ISE 2013).

Only a few scholars explicitly deal with the additionality of CDM biomass power projects. Stua (2013) finds that, in the case of China, the national feed-in tariff made "most of the biomass-fuelled power plants [cost-competitive] against [...] coal-fired plants".

Overall, based on the information presented above, we cannot clearly conclude on the likelihood of the additionality of biomass power plants.

4.7.4. Baseline emissions

As outlined in Section 4.7.2, the identification of the baseline scenario and the demonstration of additionality are conducted in parallel, considering a wealth of different options.

One key requirement in methodologies for using biomass residues is that the biomass residues would not be used in the absence of the project and would be left to decay (sometimes aerobically, sometimes anaerobically also claiming CH_4 baseline emissions). This requirement is appropriate and important due to potential competing uses for the biomass. If the biomass residues were used in the absence of the project for other purposes, there may be no emission reductions, since the diversion of biomass from one use to another due to the CDM may lead to increased emissions elsewhere. If CDM projects only divert the use of biomass residues but do not result in more biomass residues being collected which would otherwise decay, this may also lead to indirect land-use change, i.e. due to the increased use of biomass (residues), previous demand may be covered by drawing on biomass from other areas, thus leading to decreasing carbon stocks there.

Methodologies vary with regard to how they assess that the biomass residues are indeed 'available in abundance' and that decay is a likely scenario. In older versions, the abundance of biomass residues had to be monitored annually, while in newer versions this is only checked once at the project start and at the renewal of the crediting period.

[72] For small-scale biomass projects, the same additionality rules as for wind power apply (Section 4.5.2).

In general terms, there is an increasing demand of biomass for different uses (food, raw materials, energy) worldwide. This means that biomass residues (in many cases) either already have or will likely have a price in the future. As a consequence, the demonstration that biomass residues would otherwise be (completely) left to decay needs to take current market developments into account. For this reason, a regular checking of the abundance of biomass residues through monitoring may be more appropriate than a simple check once at the project start.

Furthermore, in many cases, anaerobic decay of biomass is claimed by project developers. However, this assumption may be contested depending on the circumstances. For instance, if biomass waste is spread on fields, biomass decay is rather aerobic than anaerobic, thus producing little or no methane emissions. In many instances, the amount of methane emissions claimed appears very large; it may be questionable whether truly anaerobic conditions prevail in the typical circumstances in which biomass residues are left to decay. We therefore conclude that the current approach of demonstrating the abundance of biomass residues may lead to a risk of over-crediting as no adequate monitoring of availability of biomass residues is in place. In addition, exaggerated claims of anaerobic decay of biomass may lead to further over-crediting.

With regard to the baseline emissions from displacing power plants in the grid, the same conclusions apply as discussed in Section 4.5.4.

4.7.5. Other issues

No other issues were identified.

4.7.6. Summary of findings

Additionality	• Significant impact of CER revenues on plant profitability due to claims of methane emission reductions • In many cases **competitive with fossil generation** (LCOE) • **Support schemes** exist
Over-crediting	• Demonstration that **biomass** is left to **decay or available in abundance** is only conducted once at the start of the project activity • Risk of **exaggerated claims of anaerobic decay**
Other issues	• None

4.7.7. Recommendations for reform of CDM rules

Due to our finding that the demonstration of abundance of biomass as well as of the claim that biomass is left to decay (under potentially anaerobic conditions) is key for avoiding any over-crediting of emissions, it is recommended that corresponding provisions in the applicable methodologies are reviewed, with a view to ensuring that this demonstration considers current trends of biomass use and disposal and that any claims for anaerobic conditions of biomass decay are realistic. In particular, the monitoring of biomass abundance should be carried out more frequently (e.g. annually).

4.8. Landfill gas

4.8.1. Overview

Decomposition of solid waste in landfills generates carbon dioxide (CO_2) and methane (CH_4). This landfill gas can be captured and flared or captured and utilised for electricity production or as a fuel. GHG emission reductions are achieved through the destruction of methane, and in the case of energy production, displacement of a more GHG-intensive energy source. Global estimates suggest that 50 Mt of methane are generated annually from landfills (IPCC 2014).

The composition of landfill gas is usually approx. 50% CO_2 and 50% CH_4 (Hoornweg & Bhada-Tata 2012; US EPA 2013). It varies by climate and waste composition. In general, methane generation increases in wetter versus arid climates and warmer versus cooler climates. Warmer climates increase the growth of methane-producing bacteria (US EPA 2013). Waste composition with a higher percentage of organic material generates more methane and degrades more quickly (US EPA 2013). Waste in lower income countries often includes a higher percentage of organic material than higher income countries (Hoornweg & Bhada-Tata 2012).

4.8.2. Potential CER volume

The potential to capture landfill gas varies by landfill management type. Gas collection rates can be as high as 75% for basic landfills in which waste is compacted and covered and up to 85 - 95% for engineered sanitary landfills whereby landfills are lined or capped to prevent leakage or contamination from the waste (US EPA 2013). Landfill management practices vary by region. While the majority of landfills in developed countries are engineered landfills, in developing countries mitigation opportunities are more limited because the majority of landfills are basic landfills or open dumps (US EPA 2013). In open dumpsites, decomposition is predominantly aerobic; as a result methane generation rates are relatively low and gas recovery rates are limited (~10%) (US EPA 2013). Because there is often a high concentration of food waste and wet condition in developing country sites, waste decays quickly and the methane gas is released quickly. As a result, mitigation activities to capture methane must be implemented on active open dumpsites, since after a lag of even 1-2 years most of the methane will have already been generated[73] (US EPA et al. 2012).

There are two primary landfill gas methodologies under the CDM. ACM0001 is the consolidated large-scale methodology and AMS-III.G is the small-scale methodology. As of 1 July 2015, there were 364 registered landfill gas projects. Predominantly these are large-scale projects located in Latin America and Asia/Pacific regions, though there are also projects in Africa, Europe/Central Asia and the Middle East. Of the 364, 149 projects have issued a total of 69 million CERs. As of 1 August 2015, the average issuance success rate amounted to 58% (UNEP DTU 2015a).

4.8.3. Additionality

Prior to 2013, large-scale landfill gas projects assessed additionality according to the CDM "Combined tool to identify the baseline scenario and demonstrate additionality". This tool, similar to the CDM 'additionality tool' requires that projects demonstrate that they are additional based on either an investment or a barrier analysis, complemented by a common practice analysis. Similarly, prior to 2014, small-scale projects applied the general guidelines or tool for small-scale activities. Most projects used investment analysis to demonstrate additionality, predominantly benchmark analysis or simple cost analysis (IGES 2014, similar to earlier results from Spalding-Fecher et al. 2012).

A standardized approach to additionality assessment was incorporated into Version 15 of ACM0001, eligible as of 8 November 2013, and version 9 of AMS-III.G, eligible as of 28 November 2014. This revision established a positive list for additionality of landfill gas projects. All landfill gas projects are automatically considered additional if prior to the implementation of the project they only vented or flared methane, and if under the project activity they either flare the methane, or use methane to generate heat, or use the methane to generate power with a capacity of less than 10 MW. As of 1 May 2014, only one landfill gas project had been registered using this methodology

[73] While not applicable for the landfill gas methodology (ACM0001), the rapid decay rates may have implications on the applicability of the first order decay model used in the CDM "Tool to determine methane emissions avoided from dumping waste at a solid waste disposal site" and included in the avoided landfilling via composting methodologies.

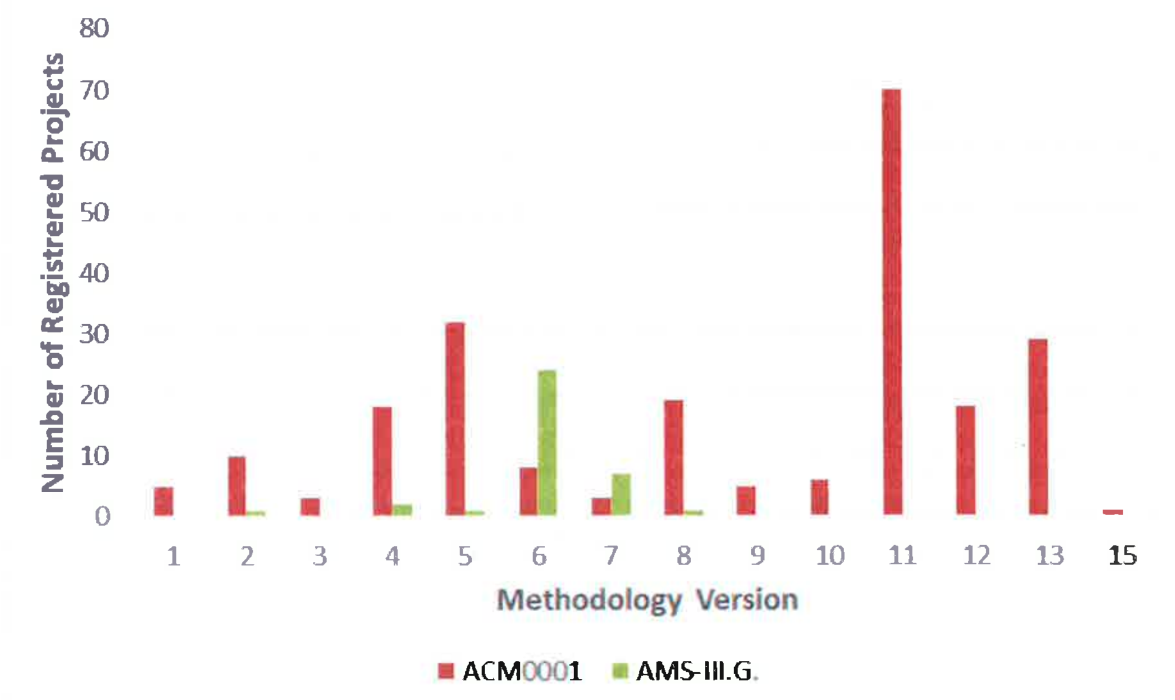
Version 15, as shown in Figure 4-8. The CDM EB will review the validity of these standardized procedures after a three-year time period.

CDM projects can only claim emission reductions for methane capture that exceeds any applicable regulations. In regions in which a regulation is in place but it can be demonstrated that it is not enforced, projects can still claim emission reductions for implementing the regulation. This has raised concerns that enforcement may be discouraged by constituencies receiving CER revenues. One such example is in the Philippines, where regulation has been established requiring gas capture and destruction, but it has not been enforced. Concerns have been raised that CER revenue has led to a pressure to discourage enforcement (Docena 2010).

Projects that capture and flare methane have no independent revenue source (US EPA et al. 2012). Flaring projects are therefore very likely to be additional. For projects using landfill gas for energy generation, additionality seems likely. As shown in Section 2.4, the available data from CDM projects indicates that the IRR is rather low without CER revenues (approx. 2.5-2.8% on average) but increase substantially with CER revenues (to approx. 16.6-18% on average). Indeed, collection and flaring of landfill gas is not common practice in developing countries without carbon finance, though it may be possible to implement projects economically where there are renewable portfolio standards (RPS) or feed-in tariffs, to allow energy production revenue to cover costs and provide capital investment for methane collection systems. For projects that supply heat, electricity, or methane to natural gas pipelines, the price and revenue from energy generation are a primary driver of the economics of the project. With economies of scale, the larger the landfill gas project, the more energy can be generated and the more likely the project is profitable.

Overall there are no substantial concerns with the approach to assess additionality for large- and small-scale landfill gas projects. The primary lingering concern is the potential for CDM projects to discourage the implementation of regulations that require capture and destruction of landfill gas.

Figure 4-8: Number of registered landfill gas projects by methodology



Source: IGES 2014

4.8.4. Baseline emissions

The baseline scenario for ACM0001 and AMS-III.G is assumed to be the atmospheric release of methane, unless capture and flaring is required by regulation or unless capture occurred to some extent prior to the implementation of the project. Baseline emissions are determined based on the amount of methane flared or used under the project activity (less any methane gas that was flared under the baseline). The overall volume of emission reductions generated is based on the baseline emissions minus any combustion efficiency losses and minus any methane that would have been destroyed under the baseline via soil oxidation. ACM0001 considers four different cases for how to account for regulation and existing landfill gas capture systems. These include no regulation/no existing capture system, no regulation with existing capture, regulation without existing capture, and regulation with existing capture. The small-scale methodology uses, in principle, the same approach but is less specific; the baseline emissions must take into account the volume of landfill gas required to be collected by regulation and the presence of pre-existing landfill gas collection and combustion systems. The overall approach of estimating the baseline emissions based on the amount of captured gas seems reasonable. However, there are concerns related to the default assumptions for pre-existing systems and regulations, and the accounting for soil oxidation.

If a regulation requires the collection of landfill gas or if a landfill gas collection system was pre-existing, but the regulation does not specify the amount to be collected or the historical amount collected is not known precisely, then both methodologies assume that 20% of the amount captured under the project scenario would be captured in the baseline. The methodology explains that this default value is based on assumptions that the capture efficiency of the project system is 50% and under the baseline 20%, and that in the baseline the methane was flared using an open flare with an efficiency of 50%. Despite the explanation, it remains unclear how the overall default value of 20% of project emissions is derived. While a 50% destruction efficiency for an open flare is conservative when considering project emissions, used in the context of baseline emissions it has the potential to actually overestimate the emission reductions. The methodologies implicitly assume that the CDM project captures five times the amount of methane than would be captured under a regulation. This assumption seems rather optimistic and likely leads to a significant over-estimation of emission reductions.

There are two types of soil oxidation that can occur at a landfill. Top-layer soil oxidation refers to soil oxidation under baseline conditions when methane oxidizes as it passes through the top layers of the landfill. The second type of oxidation can occur when additional air is introduced into the landfill due to suction from the LFG capture system under the project scenario.

Early versions of ACM0001 and AMS-III.G did not account for these two effects. This likely led to an overestimation of baseline emissions for projects that were registered up to version 11 of ACM0001 (valid until 25 July 2012) and up to version 7 of AMS-III.G (valid for registrations until 28 May 2013). This shortcoming was recognised and, in principle, addressed from version 12 of ACM0001 and version 8 of AMS-III.G onwards, by introducing a default factor for the amount of methane that would oxidize in the baseline, using 10% for "managed solid waste disposal sites that are covered with oxidizing material such as soil or compost" and 0 "for other types of solid waste disposal sites".

Concerns have been raised about the default values applied for the soil oxidation factor. Methane oxidation in covered landfills occurs mainly through bacterial degradation, primarily by methanotroph bacteria, resulting in production of carbon dioxide, water, and biomass. The rate of oxidation is influenced by a variety of physical factors, including different soil cover types (Chanton et al. 2009). Methane oxidation generally increases with temperature up to around 40°C and is also influenced by moisture, where either too dry or too wet conditions can inhibit methane oxidation (Chanton et al. 2009; Spokas & Bogner 2011). Soil oxidation further depends on the type of soil cover and the thickness of soil cover. Higher soil oxidation rates occur in landfills that are well managed with a thick soil cover. In a study of landfills with similar operational characteristics in different climate zones of the United States, methane oxidation was lowest in humid subtropical regions and highest in arid regions (Chanton et al. 2011). This research suggests that for poorly managed landfills in humid sub-tropical and tropical regions the soil oxidation rates may be very low.

The IPCC sets default values for landfill cover methane oxidation are typically between 0% and 10% of generated CH_4 (IPCC 2006), possibly derived from one early study of a New Hampshire landfill. The 2006 IPCC Guidelines for National Greenhouse Gas Inventories indicate that:

"The use of the oxidation value of 10% is justified for covered, well-managed solid waste disposal sites to estimate both diffusion through the cap and escape by cracks/fissures. The use of an oxidation value higher than 10%, should be clearly documented, referenced and supported by data relevant to national circumstances."

This highlights that the 2006 IPCC Guidelines consider a soil oxidation value of 10% as justified only for covered and well-managed sites. However, more recent literature surveys and experimental studies indicate that oxidation rates for covered landfills are higher, amounting on average to approx. 30% (Chanton et al. 2009; Chanton et al. 2011), although the 2009 paper indicates that the data may over-represent warmer conditions when oxidation rates would be higher.

Some stakeholders have raised concerns that the soil oxidation factor was not adjusted upwards in the CDM methodologies when more recent research indicated that an average value of 30% may be more representative (Chanton et al. 2009). However, the higher soil oxidation rates reported by

(Chanton et al. 2009) may not be fully appropriate for the context of developing countries, given that both an intermediate and final cap would have to be in place to a certain engineering standard. In most developing countries, landfills are rarely well managed with a thick soil cover required for this level of soil oxidation. This suggests that the higher soil oxidation rates may not be applicable to the conditions for some CDM projects. Nevertheless, having a default factor for both managed and unmanaged landfills avoids creating a disincentive for covering and managing landfills. The use of the soil oxidation rates as a standard default for all projects runs the risk of underestimating the volume of credits generated in some sub-tropical and tropical regions with unmanaged landfills for which soil oxidation rates under the baseline would have been very low or zero.

4.8.5. Other issues

Stakeholders have commented in public submissions to the UNFCCC with regard to revisions of ACM0001 that different types of perverse incentives can arise from landfill gas projects. Two main perverse incentives can be of concern, which both lead to an over-estimation of emission reductions.

Firstly, project developers can have an incentive to store the waste in a manner that generates more methane. For example, a 'flat' landfill with low methane generation potential could be changed to store waste at a greater height. Moreover, project proponents can have an incentive to maximise methane generation through other means, such as pulling water in the landfill to create anaerobic conditions. On a site visit to a landfill gas project in China in 2005, engineers proudly explained how they had found a way to generate more methane by stacking waste higher in one section of the landfill rather than spreading it evenly across the landfill site. While this is just one anecdotal example, there is reason to believe that some landfill projects may be altering management practices to do so. Based on these observations, in 2012 more recent versions of both the large- (version 13.0) and small-scale methodologies (version 8.0) included an applicability criterion that excludes projects in which the management is changed in order to increase methane generation. However, verifying this requirement may be difficult in practice and it has not been included as an explicit provision for DOEs to assess after the project implementation.

Secondly, there could be perverse incentives for policy makers and private actors not to engage in recycling or other ways of preventing waste generation, as this could lower the potential for CDM landfill gas projects. Similarly, there could also be perverse incentives to continue landfilling instead of introducing other waste treatment methods (incineration, composting).

Public comments received on behalf of waste picker organizations have raised concerns that development of a project limits access of waste pickers who, through the informal economy, contribute significantly to the recycling of materials (Global Alliance for Incenterator Alternatives, GAIA). Project developers who were interviewed acknowledged that sites need to be secured for project installation, to avoid having equipment tampered with or material stolen. For certain projects, including examples in Latin America and Thailand, agreements have been made for waste pickers to pick through waste before it is transferred into the secure site. However, in other cases there has not been any cooperation between the project developers and waste pickers, which has resulted in conflict and loss of livelihoods. There is evidence that the development of landfill gas projects is limiting the access of waste pickers and thereby reducing the reuse and recycling of waste through the informal economy. Given the success of collaborative agreements with waste pickers, this may be a model which new projects should be required to incorporate.

Pursuing landfilling instead of other waste treatment methods, such as recycling, incineration or composting, is likely to result in overall higher GHG emissions, even if the landfill gas is captured, because landfill gas collection systems are not able to capture all of the methane. The CDM may thus provide perverse incentives for policy makers or project owners to continue pursuing a waste treatment method that is more GHG-intensive. If in the absence of the CDM, other waste treatment methods would be pursued, it would lead to an over-estimation of emission reductions.

Early versions of CDM methodologies did not include any provisions to address this issue. Regarding the potential perverse incentive to reduce recycling, starting with version 12 of ACM0001, an applicability criterion requires that "the implementation of the project activity does not reduce the amount of organic waste that would be recycled in the absence of the project activity". However, there is no reference to how this should be assessed. Moreover, this applicability condition does not address the broader concern that the CDM provides incentives to continue pursuing landfilling and not composting or waste incineration. In public comments submitted by non-governmental organisations, such as the GAIA, there have been calls for eligibility requirements that would allow projects only on closed landfills in order to prevent the potential for this perverse incentive of reducing recycling and composting. Project developers argued that in developing country contexts, with warmer climates and higher percentage of organics in the waste stream, the capture of methane must take place while the landfill is actively being used, otherwise the methane will have already been released once it is closed. This is in contrast to landfills in more temperate climates, where methane production happens more slowly and where it is more common to develop a project at a closed landfill.

Overall, there is reason to believe that landfill gas projects are contributing to perverse incentives to manage landfills in ways that generate more methane and to reduce reuse and recycling or avoid a shift towards compositing or waste incineration. In addition, it appears there are cases in which project participants increase methane production – an issue which may deserve particular attention in the validation and verification auditing processes.

4.8.6. Summary of findings

Additionality	• Likely to be additional
Over-crediting	• Default assumptions for the rate of methane captured under pre-existing collection systems or regulations are unjustified and have the potential to overestimate emission reductions • Default soil oxidation rates may underestimate emission reductions for uncovered landfills in humid sub-tropical and tropical regions with very low soil oxidation rates; nevertheless, requiring the use of a default soil oxidation rate for baseline emissions avoids creating a perverse incentive to avoid covering landfills • Potential for perverse incentives for policy makers not to regulate landfills or enforcing regulations in place • Perverse incentives for project developers to manage landfills in ways that increase methane generation
Other issues	• Perverse incentives for policy makers not to pursue less GHG-intensive waste treatment methods, such as composting or incineration • Some landfill gas projects exclude waste pickers and informal sector recycling, reducing overall rates of reuse and recycling

4.8.7. Recommendations for reform of CDM rules

We recommend several revisions to the CDM landfill gas methodologies to address the potential over-crediting, in particular the perverse incentives for both project owners and policy makers:

- Instead of applying one value for the soil oxidation factor to all projects, different values could be applied to different regions based on the climatic conditions and practices in that region.

- The approach of the default factors used for estimating methane capture from pre-existing collection system or landfills with regulations should be revisited. Assumptions in the default factor could be revised to be more conservative by assuming that more (rather than less) methane was captured and destroyed.
- Include specific requirements for DOEs to verify that the landfilling practice was not changed with a view to generating more methane.
- To avoid the reduction in recycling by excluding waste pickers access to the site, the methodology could be revised to be more specific about how projects should provide waste pickers with access to solid waste before it is deposited in the secure dumpsite.
- Given the long-term need to transition away from landfilling and increase composting and recycling, there could be a sunset clause considered for CDM landfill projects.

4.9. Coal mine methane

4.9.1. Overview

Methane is stored within coal as part of the coal formation process. During coal mining activities some of the methane is released. The build-up of methane in coal mines creates a potential explosive hazard and efforts before, during, and after mining are taken to reduce the safety risk by releasing methane into the atmosphere. Methane released from coal mines makes up approx. 8% of global anthropogenic methane emissions (Global Methane Initiative 2011). Methane originating in coal seams that is drained prior to mining is known as coal bed methane (CBM). Through a process of pre-mining drainage, this methane can be extracted to reduce the safety risk. During coal mining, methane can be vented from coal mines, which is known as ventilation air methane (VAM). After mining has ceased, methane can be extracted, which is known as post mining or post drainage coal mine methane (CMM). Coal mine methane projects involve installation of control technologies to collect and destroy and/or utilise methane from existing and abandoned mines, instead of releasing it to the atmosphere. Under the ACM0008 methodology of the CDM, capturing methane is eligible from pre-mining via underground boreholes and surface drainage of CBM, during mining from VAM that would normally be vented, as well as post mining from abandoned/decommissioned mines.

4.9.2. Potential CER volume

Of the 84 CMM projects that have been registered under the CDM, all are located in China, except for one project in Mexico. Projects from other countries, including India, Indonesia, Philippines and South Africa have been submitted to the UNFCCC but not registered.[74] As of 1 May 2014, 34 million CERs have been issued from 37 projects located in China. The total volume of credits expected from the credit start dates up to 2020 is 170 million CERs (Section 2.3).

The best conditions for CMM projects are deep coal mines with high methane concentrations. Under these conditions, methane is concentrated and easy to collect. For geographic and regulatory reasons, coal mines in China have been well suited for CMM projects to date. In India, for example, most coal mines are surface mines, where methane concentrations are lower and it is harder to collect the methane. Another barrier in India is national regulation that divides permits for using coal and gas. This means that coal mines do not have a permit to utilise the methane gas generated and would be unable to authorise a CMM project. A CMM project would require an additional permit process, an added administrative barrier.

[74] There are two projects under validation from India and one from the Philippines. Projects in Indonesia and South Africa have had their validation terminated or validation replaced.

4.9.3. Additionality

All of the registered CMM projects use the large-scale ACM0008 methodology. The most recent ACM0008 Version 8 requires use of the "Combined tool to identify the baseline scenario and demonstrate additionality" and provides further guidance on the application of the tool in the context of CMM projects. As of May 2014, no projects had been registered under version 8, which was approved in February 2014. The majority of projects are registered under versions 6 and 7. In these prior versions, the CDM additionality tool was applied, and a separate procedure was used to select the baseline scenario. Starting with version 6, the methodology was changed to allow for benchmark analysis as part of investment analysis for projects where no investment would occur in the baseline scenario.

Most CDM CMM projects apply a benchmark analysis to demonstrate additionality, as shown in Table 4-4. Benchmark analysis compares the financial performance of the project, often expressed as IRR, to a relevant benchmark or investment 'hurdle rate'. In contrast to some other project types, CER revenue for CMM projects does make up a large portion of the return on investment on capital expenditures for projects. According to information from PDDs, the IRR without CER revenue is approx. 2% on average and increases to approx. 28% with CER revenues, the largest increase among all project types (Section 2.4). When we derive a simple indicator that puts the capital investment in relation to the number of CERs generated over ten years, as referenced in Section 2.4 in this report, we find an average ratio of about USD 4 / CER for all CMM projects. These calculations show that CMM projects have a high likelihood of additionality. They support reports from technical experts and project developers that abatement costs for CMM co-generation plants are approximately USD 3 - 5 per tCO_2 during 10 years of operation. Other reports indicate that CMM projects are usually not economically viable; according to United Nations (2010) power generation from CMM only becomes economically viable for coal mines with very large methane sources exceeding 20 m^3/t (United Nations 2010).

Table 4-4: Additionality approaches used by CDM CMM project activities

Additionality approach	Number of project	Average Annual CERs (1,000)
Benchmark Analysis	76	33,465
Investment Comparison Analysis	4	1,557
Investment Comparison Analysis and Benchmark Analysis	1	266
Simple Cost Analysis	4	1,883

Sources: IGES 2014

A high likelihood of additionality is also supported by observation of common practice in the sector. Coal mines are very averse to having any combustion on-site. Combustion of any kind increases the potential risk of a methane gas explosion. Venting methane is the safest approach to avoid combustion, and miners and management are very familiar with this approach. Coal mine operators are generally averse to having a methane combustion system onsite as a result in order to avoid the risk of mine closures due to concerns around worker safety. Global Methane Initiative staff reported that in China, prior to the presence of the carbon market, efforts by the Global Methane Initiative were wholly unsuccessful in implementing CMM projects. No pilot projects or sponsored projects were able to get off the ground. Technical barriers were significant and persistent. The equipment used was unable to cope with the difficulties of the coal mine system, including the concentrations of volatile methane and the gas volumes. Only with the revenue from CERs were there sufficient incentives to develop technologies that worked well for these conditions. Now, in

China, it has become common practice for large coal mines to capture methane with revenue from a CDM project. As of 2014, there were still 2 projects in China at the validation stage; however since the technology for developing CMM projects in China is now proven, it can no longer be claimed to be first of its kind or a technology barrier. Although the CMM projects have become common practice, this has only been the case with CDM revenue. Overall, the risk for non-additionality is low for VAM projects.

4.9.4. Baseline emissions

Baseline emissions are calculated as the sum of CO_2 emissions from destruction of methane that would occur in the baseline scenario, emissions from the production of power, heat, or use of gas replaced by the project activity, and release of methane into the atmosphere that is avoided by the project activity. The baseline scenario is selected based on an examination of all the options that are technically feasible and comply with applicable regulations and elimination of all baseline scenario alternatives that face prohibitive investment, technological and/or prevailing practice barriers.

There is some concern that mines may take part in marginally more pre-mining drainage than they would have done without incentives from the CDM; however, the drained methane would likely have been emitted upon mining (and likely would have been emitted through ventilation later on). So these concerns seem limited, given that there are provisions in the methodology that emission reductions may only be credited once mining starts, ensuring that CERs are not issued in cases in which mining may not have occurred under the baseline. Our review has not identified any other concerns related to the determination of baseline emissions.

4.9.5. Other issues

The methodology includes a requirement that methane collection must exceed that which is required by applicable regulations, with the exception of cases in which it can be shown that the regulation is not enforced. A regulation was put in place in China requiring that methane captured from coal mines that exceeds 30% methane concentration must be captured and used. It has been suggested by project proponents that the Chinese government actually put this regulation in place as a result of the success of the CDM, to support the use of CDM financing to capture methane as best practice and to stimulate more CDM project development. However, interpretations vary and it has led to questions around the additionality of projects and whether or not they would have been required by regulation. As a consequence, project developers focused on projects where the methane concentration was below 30%. These projects would be avoided for safety reasons in North America or Europe, because this gets close to the explosive range of methane concentrations of 15-25%. It is better practice and safer to improve the capture rate and increase the concentration of methane, however this could run the risk of exceeding the 30% concentration regulatory requirement in China, and hence not meeting the CDM additionality requirements. This raises the risk of perverse incentives for project developers to diluting methane gas to reduce the concentration below 30% in order to be eligible for the CDM. However, no evidence is available whether this happened.

4.9.6. Summary of findings

Additio-nality	• Likely to be additional • CDM revenue makes up a large portion of return on capital investment • Technology for CMM in China is now well demonstrated, no longer technical barriers
Over-crediting	• Potential concerns regarding increased mining and/or pre drainage of coal mine methane but no evidence whether or not this occurs
Other issues	• Potential perverse incentives to dilute methane in order to avoid that abatement is required by regulations

4.9.7. Recommendations for reform of CDM rules

There are no recommendations regarding reforming the CDM rules for CMM projects. Further investigation of China's regulations for methane capture are warranted to ensure that perverse incentives are avoided.

4.10. Waste heat recovery

4.10.1. Overview

Waste heat utilization includes generally energy efficiency measures, where the thermal content of hot waste gases that would be vented in the absence of the CDM project activity is used for heating purposes, replacing fossil fuel use. For example, hot exhaust gases from cement kilns can be used to pre-heat the raw material before entering into the kiln.

A related category of projects is waste gas utilization where the calorific value of waste gases that contain a certain fraction of hydrocarbons or hydrogen that would be flared in the absence of the CDM project activity is used to replace regular fossil fuels. For example, waste gases with a high content of carbon monoxide and hydrogen can be used as fuel for steam production in industry. This second project category has similar features than the 'thermal' recovery of waste gases, but the present chapter focusses on the first category.

4.10.2. Potential CER volume

According to our own estimates, registered CDM projects have the potential to issue 0.35 billion CERs by the end of their respective crediting periods, of which 0.22 billion CERs fall in the period from 2013 to 2020 (Table 2-1). CERs from these projects account for about 2.5% of the total CER issuance potential.

4.10.3. Additionality

The methodologies for waste heat utilization (AM58, AM66, AM95, AM98, ACM12, AMS-II.I., AMS-III.P.AMS-III.Q., AMS-III.BI.) generally use standard CDM additionality tests based on barrier and/or investment analysis.

The general issue with this project type is that the use of waste heat is a standard practice in many integrated industrial facilities, in particular where energy costs represent a larger fraction of production costs such as in cement production, refineries, iron and steel and chemicals. However, the extent of the use of waste heat and energy efficiency may vary significantly even within a country, as energy costs, financial resources and engineering and management skills may differ between sectors and plants. While one steel plant may define its competitive edge in systematically using all waste heat and reducing heat loss along the steelmaking process because of competitive steel markets and relatively high fuel costs, a refinery plant may vent significant amounts of waste heat and experience severe heat losses all over the refinery because its cost of fuel is very low.

In the use of investment analysis for demonstrating additionality for waste heat recovery projects involves several uncertainties: the highest uncertainties are in the in the assumptions on future fuel prices which show high variability over time (Figure 2-4 to Figure 2-6). In addition, the considerable uncertainties in investment cost for equipment and construction and the often uncertain impact of the considered measure on efficiency makes it difficult to objectively determine the profitability of the measure and the relevant hurdle rate (Section 3.2).

For projects implemented in existing plants, the methodologies require demonstrating that the waste heat or gas has been flared/vented at least three years before the project implementation. This is an important safeguard to assure at least some degree of additionality.

Some methodologies, such as ACM0012, also allow waste heat recovery projects in greenfield plants. This is very problematic, as it is very difficult to demonstrate that the waste heat utilization would not have been implemented in the absence of the CDM (Section 3.2). The methodology ACM0012 (V.5) provides for two options for demonstration additionality in the case of greenfield plants. Option 1 requires to identify similar plants; the project is deemed as additional "if *more than 80 per cent of the analyzed facilities in the list do not use waste energy, it can be decided that the proposed Greenfield facility also would have wasted the energy in the absence of waste energy recovery CDM project*". While the methodology tries to be descriptive on how to identify baseline waste energy use, there remain large uncertainties and most importantly, data on the degree of waste energy usage in plants from competitors may be very difficult to obtain. Under option 2, project participants can submit a (hypothetical) *alternative design* without or with a lower level of waste heat recovery and demonstrate using investment analysis that the alternative design would be the baseline scenario for the waste energy generated in the greenfield facility. Given the high uncertainties in price data and hypothetical level of waste heat utilization in the absence of the CDM, this leads to significant risks of non-additionality.

The economic impact of CERs on the profitability of the waste heat recovery project is usually rather small compared to related fuel cost saving. I.e. a change in fuel costs of a few percent may have the same impact as the CER revenues (Sections 2.4 and 3.2).

Overall, the risk for non-additionality of greenfield plants seems higher than for existing plants, where the requirement for a minimum of three years of generation of waste heat prior to the start of operation of the CDM project has to be demonstrated.

4.10.4. Baseline emissions

Baseline emissions are usually derived from the amount of waste heat used in the project case. It is assumed, that this heat would be generated by fossil fuels in the baseline scenario.

However, even though the methodologies for existing facilities require demonstrating that the waste heat or gas has been flared/vented at least three years before the project implementation, in practice it may be very difficult to rule out that waste heat has not been used in some form in existing facilities before project implementation, which may inflate baseline emissions.

Also, waste heat recovery may lead to a different operation of the plant than in the baseline scenario. For example, if waste heat is used for pre-heating of a product, the plant may be run in such a way that more waste heat is generated to assure a certain temperature level of the pre-heated product, which leads to a higher fuel consumption in the boiler generating the waste heat. Therefore the amount of heat wasted in the baseline may be overestimated. Moreover, baseline usually do not capture any other autonomous energy efficiency improvements that might be implemented in the absence of the project.

In greenfield projects, the emission reduction is based on the difference in emissions in modelling a baseline and project scenario. The models build on many assumptions that are difficult to validate objectively. The results are therefore prone to high uncertainty and may lead to over-crediting.

Lastly, the methodologies do not consider emission reductions from the reduction in upstream emissions (such as from the production of natural gas or coal) which leads to a slight under-crediting, if upstream emissions occur in a non-annex I country.

4.10.5. Other issues

None.

4.10.6. Summary of findings

Additio-nality	• CER revenues are very small compared to cost reduction from fuel savings • Ex-ante estimation of key parameters including investment costs and fuel savings has large uncertainties • Waste heat recovery is common practice in many countries and sectors (though not in all)
Over-crediting	• In existing facilities: It is very difficult to rule out that waste heat has not been used in some form before project implementation, which may inflate baseline emissions • In greenfield projects: Modelling of amount of waste heat lost in baseline is subject to very high uncertainties. • Waste heat recovery may lead to a different operation of the plant than in the baseline case, e.g. to assure a certain temperature level of the heat medium or to NCV level of waste gas, therefore the amount of gas wasted in the baseline may be overestimated
Other is-sues	• None

4.10.7. Recommendations for reform of CDM rules

Waste heat recovery is standard practice in many energy intensive industrial sectors, though there exist barriers to the implementation of waste to energy measures. The high uncertainty in additionality demonstration make it less suitable for the CDM, the project type may be taken out of the CDM or restricted to cases with clear additionality demonstration, e.g. of a very low uptake of waste heat recovery can be demonstrated in a specific industrial sector. We recommend that option 1 in Appendix 1 of ACM0012 be maintained as it provides a more objective way of assessing the practice in the sector and country and that option 2 not be used.

4.11. Fossil fuel switch

4.11.1. Overview

Fossil fuel switch includes the switching from a fuel with higher carbon intensity (such as coal or petroleum) to a fossil fuel with lower carbon intensity (such as natural gas) in the generation of heat for industrial processes or in power plants. In this section we do not consider switching from fossil fuels to biomass. Methodologies are for existing installations only (e.g. ACM0009, ACM0011, AMS-III.AH., AMS-III.AN) or for both existing and greenfield installations (AMS-III.B and AMS-III.AG – power only).

4.11.2. Potential CER volume

According to our own estimates, registered CDM wind power projects have the potential to issue 0.46 billion CERs by the end of their respective crediting periods, of which 0.23 billion CERs fall in the period from 2013 to 2020 (Table 2-1). CERs from wind power account for about 3.3% of the total CER issuance potential.

4.11.3. Additionality

Both fossil fuels with higher carbon intensity such as hard coal, lignite or fuel oil and fuels with lower carbon intensity such as natural gas are widely used in stationary installations in energy and manufacturing industries as well as in the buildings sector. In existing facilities, the choice of fuel is often determined by the existing fuel, because fuel changes may be costly, though there are also multi-fuel systems. In greenfield plants, the fuel choice usually depends on the economic viability of each fuel option.

Table 4-5: Examples of differences in characteristics between the use of coal and fuel oil compared to natural gas

Characteristics	Hard coal, lignite (fuel with high carbon intensity)	Natural gas (fuel with lower carbon intensity)	Considered in investment analysis
Initial investment for burner/ boilers etc.	Higher	Lower[1)]	Yes
Fuel cost per energy unit	Lower	Higher	Yes
Non-fuel operation costs	Higher	Lower	Yes
Flexibility in operation[2)]	Lower	Higher	No
Means of distribution to end-user	Vehicle-based: by trucks, train i.e. requires access roads or rails	Network based: by distribution lines[3)]	No
Price building mechanisms	In many countries based on world market price	In many countries price is based on local long term contracts, often taking into account a price index, e.g. based on oil price	No
Dependence on specific supplier	Lower	Higher	No
Compliance with local air quality standards (if any)	More difficult: Coal based furnaces may require expensive exhaust cleaning systems	Less difficult: Natural gas based furnaces have generally lower air pollutant emission levels[4)]	No
Need of space for local fuel storage	Yes	No[5)]	No

Notes: [1)] This is the case if the (higher) investment for distribution lines necessary to connect to the natural gas grid is borne by a different entity, e.g. the natural gas supplier. In case of LNG initial investment costs may be somewhat higher for LNG terminals, local storage facilities etc. [2)] E.g. shorter time lag to start-up operation of power plant if dispatching system in a grid requires more power. [3)] Or Vehicle based in case of LNG. [4)] Please note that this may hold true even though local air quality standards may be stricter for natural gas than for coal-based systems. [5)] Except for LNG.

Sources: Author's own research

The large-scale methodologies ACM0009 and ACM0011 require an investment analysis for demonstrating additionality, a barrier analysis (Section 3.2) is not deemed sufficient.[75] This makes sense as the economic viability may be seen as one of the key aspects when deciding on a specific fuel. Requiring investment analysis may reduce the risk of non-additionality, because using this

[75] Though e.g. ACM0009 allows for the additionality to be proven by claiming „prohibitive barriers" for the project (natural gas) scenario applying step 3 of the additionality tool.

test may be more difficult in the case of very lucrative fuel switches (e.g. if cheap natural gas becomes newly available in a project site).

In general, fuel prices per energy unit are generally lower for coal than for natural gas. This is offset to a certain degree by higher initial investment and non-fuel operation costs for coal furnaces (Table 4-5). However, while the investment analysis takes these cost factors into account, there could be other factors that may lead to the choice of natural gas as a fuel, even though it may be economically somewhat less attractive than lignite or hard coal.

An issue that contributes to the high uncertainty in investment analysis are the assumptions made about future developments of fuel prices. In the investment analysis, the fossil fuel switch methodologies allow to choose between (i) keeping fuel prices at present levels for future years, or (ii) to use future prices that *"have to be substantiated by a public and official publication from a governmental body or an intergovernmental institution"* (ACM0009 V.5, Section 5.2.4).

For small-scale projects, however, the barrier analysis is deemed sufficient, which may considerably increase the risk of non-additionality (Section 3.3). This risk is only somewhat mitigated by some small-scale methodologies requiring that the CDM project involves at least some capital investments[76], ruling out projects where fuel switch can be carried out without any investment in additional fuel switching equipment, e.g. in natural gas burners. Still, small-scale fuel switching methodologies have the full set of issues that have been identified for barrier analysis (Section 3.3).

In addition, similar to other energy related project types, with fuel switch projects CER revenues are very small compared to typical fluctuations of price differences between fuels (dark-spark spread), which increases the risk of non-additionality.

4.11.4. Baseline emissions

The exploitation, transport, processing and distribution of fossil fuels results in upstream emissions, many of which may originate in non-Annex I countries. In most CDM project types, the amount of fossil fuel used is *reduced* with the project; therefore, it may be assumed that also upstream emissions are reduced. As a conservative simplification, the relevant methodologies usually do not consider upstream emissions. In the case of fossil fuel switch, however, upstream emissions from fossil fuels could either increase or decrease. In general, upstream emissions from natural gas tend to be higher than upstream emissions from lignite, hard coal or fuel oil (depending on source of fuel).

With fuel switch activities the amount of fuel used in terms of energy content remains more or less constant (or may slightly be reduced because of higher efficiency of natural gas burners). Because of the potentially higher upstream emissions of natural gas, switching from coal/oil to natural gas may result in an increase in upstream emissions, the so-called 'upstream leakage' emissions. For this reason, CDM methodologies for fossil fuel switch projects consider upstream emissions.

The procedures for estimating upstream emissions are included in the methodological Tool "Upstream leakage emissions associated with fossil fuel use" (V.1, EB69 Annex12). The tool allows project developers to use default values for upstream emissions or to come forward with their own values derived from relevant data. The default values have been substantially revised with the tool (e.g. from the values included in Table 3 of methodology ACM0009 V.4 (EB68 Annex 12)).

For instance, according to the latest version of the tool, default upstream emissions values from natural gas are 2.9 tCO_2/TJ, based on data from the US. This is comparable to the 2.6 tCO_2/TJ

[76] For example, as in the applicability requirements of small-scale methodology AMS-III.B (V.18): "The methodology is limited to fuel switching measures which require capital investments. Examples of capital investment include creating infrastructure required to use project fuel or retrofitting existing installations."

(105 tCH_4/PJ; total) default upstream emissions in Western Europe in ACM0009 V.4 (based on IPCC), but is much lower than in e.g. the former values for Eastern Europe and former Soviet Union (23 tCO_2/TJ) or Rest of the World (7.4 tCO_2/TJ).

Also, the revised aggregated default values for natural gas (Table 1 in the tool) of 2.9 appears much lower than the sum of the default values for the different elements in the upstream chain of natural gas (Table 3 in the tool), including exploration and production (3.4 tCO_2/TJ), processing (4 tCO_2/TJ), storage (1.6) and distribution (2.2). The latter are all based on the US Department of Energy's GREET model, which may not necessarily be representative for upstream emissions of natural gas in developing countries.

With this, the revised values become comparable to those from (underground) coal. It is unclear whether this is a reasonable assumption or an artefact because of the origin of the natural gas upstream emissions data. If the values in the upstream tool are not conservative, i.e. provide too low default values for natural gas upstream emissions, this would lead to an increased risk of over-crediting of fuel switch projects.

An additional issue is the assumptions for the default values on the share of upstream emissions that are covered by caps of Annex-I countries – and how effective these caps are in limiting upstream emissions.

Table 4-6: Default emission factors for upstream emissions for different types of fuels reproduced from upstream tool (Version 01.0.0)

Fossil fuel type x		Default emission factor (tCO_2e/TJ)
Natural Gas (NG)		2.9
Natural Gas Liquids (NGL)		2.2
Liquefied Natural Gas (LNG)		16.2
Compressed Natural Gas (CNG)		10
Light Fuel Oil (Diesel)		16.7
Heavy Fuel Oil (Bunker or Marine Type)		9.4
Gasoline		13.5
Kerosene (household and aviation)		8.5
LPG (including butane and propane)		8.7
Coal/lignite (unknown mine location(s) or coal/lignite not 100%	Lignite	2.9
	Surface mine, or any other situation	2.8
	Underground (100% source)	10.4
Coal/lignite (coal/lignite 100% sourced from within host country)	Lignite	6
	Surface mine, or any other situation	5.8
	Underground (100% source)	21.4

Notes: The detailed table 3 in tool does not seem to provide data for conventional NG upstream emissions

Sources: EB69, Annex 12, https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-15-v1.pdf

Table 4-7: Former default emission factors for upstream emissions for different types of fuels

Activity	Unit	Default emission factor	Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines*
Coal			
Underground mining	t CH4 / kt coal	13.4	Equations 1 and 4, p. 1.105 and 1.110
Surface mining	t CH4 / kt coal	0.8	Equations 2 and 4, p.1.108 and 1.110
Oil			
Production	t CH4 / PJ	2.5	Tables 1-60 to 1-64, p. 1.129 - 1.131
Transport, refining and storage	t CH4 / PJ	1.6	Tables 1-60 to 1-64, p. 1.129 - 1.131
Total	t CH4 / PJ	4.1	
Natural gas			
USA and Canada			
Production	t CH4 / PJ	72	Table 1-60, p. 1.129
Processing, transport and distribution	t CH4 / PJ	88	Table 1-60, p. 1.129
Total	t CH4 / PJ	160	
Eastern Europe and former USSR			
Production	t CH4 / PJ	393	Table 1-61, p. 1.129
Processing, transport and distribution	t CH4 / PJ	528	Table 1-61, p. 1.129
Total	t CH4 / PJ	921	
Western Europe			
Production	t CH4 / PJ	21	Table 1-62, p. 1.130
Processing, transport and distribution	t CH4 / PJ	85	Table 1-62, p. 1.130
Total	t CH4 / PJ	105	
Other oil exporting countries / Rest of world			
Production	t CH4 / PJ	68	Table 1-63 and 1-64, p. 1.130 and 1.131
Processing, transport and distribution	t CH4 / PJ	228	Table 1-63 and 1-64, p. 1.130 and 1.131
Total	t CH4 / PJ	296	

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range

Sources: EB68 Annex 12, ACM0009, V 4, Table 3, http://cdm.unfccc.int/filestorage/r/t/4M2I7TA9GRCU5QDB0JLNHK6PY1ZOWE.pdf/eb68_repan12.pdf?t=Z0p8bzJ3YnExfDBVPWpbmgO_k-sMZsZIso1q

4.11.5. Other issues

None.

4.11.6. Summary of findings

Additio-nality	• Small-scale methodologies for fuel switching do not require investment analysis but may build only on barrier analysis, which provides a high risk for non-additionality • Even in large scale methodologies, modelling of fuel choice depends not only on prices, but also on availability/reliability, need for diversification, and operational needs (e.g. NG power plants for covering peak demand); this may imply that the investment analysis may not be sufficient to determining additionality • CER revenues are very small compared to typical fluctuations of the price difference be-tween fuels (dark-spark spread)
Over-crediting	• Upstream emissions need to be taken into account, but with the revised default values of the tool they may not be addressed in an adequate way anymore
Other is-sues	• None

4.11.7. Recommendations for reform of CDM rules

In sum, the revision of upstream default values as documented in the tool practically eliminates the consideration of upstream emission in a fuel switch e.g. from (underground) coal to natural gas. The assumptions behind the revisions (mostly data from the US may not be representative for the situation with natural gas used in developing countries and require urgent independent analysis and revision.

4.12. Efficient cook stoves

4.12.1. Overview

Under the CDM, there are two methodologies applicable to efficient cook stoves. AMS-II.G[77] applies to cases where inefficient existing cook stoves are replaced by improved-efficiency cook stoves to reduce the demand for non-renewable biomass. AMS-I.E[78] applies to cases where a renewable technology, such as biogas or solar cookers, is introduced to displace existing cook stoves using non-renewable biomass. The number of projects has increased quickly since the introduction of these methodologies in 2008/2009. Most notably the introduction of PoAs, enabling multiple project activities to be registered through a single approval process, has lowered the transaction costs and increased scalability for projects like efficient cook stoves.

4.12.2. Potential CER Volume

As of 1 July 2015, a total of 102 cook stove projects have been registered under the CDM, 37 as individual CDM project activities and 65 as PoAs (along with a total of 180 individual CDM Program Activities (CPAs)).

Table 4-8: Number of efficient cook stove single CDM project activities by country

Country	Number of CDM project activites	Annual CERs (1,000)	Avg. CERs per CDM project activity (1,000)
China	1	12	12
India	29	469	16
Lesotho	1	34	34
Malawi	2	71	35
Mozambique	1	192	192
Nepal	1	20	20
Nigeria	1	31	31
Zambia	1	130	130
Total	**37**	**960**	

Sources: UNEP DTU 2015a

Project activity under the CDM peaked in 2012 and dropped sharply in 2013. As of 1 July 2015, single CDM cook stove projects are mostly located in the Asia and Pacific regions (Table 4-8), while component project activities developed under PoAs are predominantly located in Africa, as shown in Table 4-9. The annual volume of CERs estimated by project developers from PoA projects is 9.2 million, nearly 10 times the annual volume of CERs projected from single CDM project

[77] AMS-II.G.: Energy efficiency measures in thermal applications of non-renewable biomass, https://cdm.unfccc.int/methodologies/DB/UFM2QB70KFMWLVO7LJN8XD1O2RKHEK.

[78] AMS-I.E.: Switch from non-renewable biomass for thermal applications by the user, https://cdm.unfccc.int/methodologies/DB/O799FU5XYGECUSN22G84U5SBXJVM6S.

activities of 0.96 million. Many of the registered PoAs have only 1 or a few CPAs associated with them (Table 4-9), so there is potential to scale up CPAs in these cases. In Bangladesh and Madagascar, many individual CPAs have already been developed under the one PoA registered in each of these countries (Table 4-9).

Table 4-9: Number of efficient cook stove PoAs and CERs by country and methodology

Country	Number of PoAs	Annual CERs (1,000)	CPAs per PoA	Annual CERs/ CPA (1,000)
Bangladesh	1	543	11	49
Burkina Faso	2	68	1	68
Burundi	2	452	4	113
China	1	10	1	10
Congo DR	3	124	1	124
Côte d'Ivoire	2	160	2	80
El Salvador	2	90	1	90
Ethiopia	3	201	2	121
Ghana	2	377	4	108
Guatemala	1	43	1	43
Haiti	2	68	1	68
Honduras	1	34	1	34
India	5	543	2	302
Kenya	4	319	2	159
Madagascar	1	4,198	59	71
Malawi	6	299	1	257
Mali	1	33	1	33
Mexico	1	40	1	40
Mozambique	1	28	1	28
Myanmar	1	43	1	43
Nepal	4	204	2	136
Nigeria	2	226	4	56
Rwanda	3	229	2	114
Senegal	3	209	1	209
South Africa	1	32	1	32
Tanzania	1	63	1	63
Togo	3	48		144
Uganda	3	265	2	132
Zambia	3	345	3	129
AMS-I.E	7	4,657	9	509
AMS-II.G	57	4,535	2	2,371
AMS-I.E + AMS II.G	1	100	1	100
Total	**65**	**9,292**		

Sources: UNEP DTU 2015a

4.12.3. Additionality

Improved cook stove methodologies under the CDM fall under one of two types: improved energy efficiency (AMS-II.G) or fuel switching to renewable energy (AMS-I.E). Under both methodologies projects must apply the CDM "Guidelines on the demonstrating of additionality of SSC project activities" (Methodological Tool: Demonstration of additionality of small-scale project activities. Version 10.0). Following these CDM guidelines, projects using either of these methodologies are on the positive list of project types and automatically considered additional so long as each unit is no larger than 5% of the small-scale CDM threshold (750 kW installed capacity or 3000MWh energy savings per year or 3,000 metric tons emission reductions per year), and end users are households/communities.

Lambe et al. (2015) reviewed PDDs for cook stove projects in Kenya and India. Although projects are considered automatically additional and were thus not required to document barriers, the study found that several did include a discussion of barriers in the PDDs. The most-cited barrier was household poverty, which makes improved stoves unaffordable. The study found that several PDDs for projects in Kenya include simple cost analysis to assess the ability of households to purchase an efficient cook stove based on their income and their costs for food and fuel; the calculations suggest that households would need to save 22–30% of their remaining income for a year to purchase a stove. This claim was supported in the pricing models the authors found used by projects in rural areas, which nearly exclusively distributed stoves for a free or subsidized price. In an urban setting, the study found that many projects were selling stoves at the retail price with microfinance options. The study noted that these PDDs suggest that since urban households are already purchasing charcoal, they have an incentive to buy an improved cook stove to reduce their fuel costs. The study authors also found that many projects also cited the lack of access to credit for working capital, low profit margins, high upfront capital costs, lack of sufficient consumer outreach and support for program operations, reduced consumer demand resulting from failure of past efforts, need for ongoing improvement and modifications of stoves to suit user needs as barriers to project implementation.

Lambe et al. (2015) also investigated what contribution offset revenues make to the overall project revenue. The study reviewed claims made in PDDs regarding the use of offset revenue and found that a majority of projects planned to use offset sale revenues to subsidize the price of improved cook stoves, as well as to cover operational costs, including maintenance and replacement of stoves, training of cook stove users, outreach and marketing to households, microcredit systems and distribution. Interviews of market actors affiliated with these projects by the authors found that while some projects were entirely dependent on offset revenue, others admitted that given the uncertainty in revenue from offsets it was advantageous not to depend on carbon revenues.

These conclusions raise substantial concerns about the additionality of improve cook stove projects under the CDM. Carbon revenues are more likely to be a primary financial enabler of projects in rural areas, where revenues are needed to subsidize the price of stoves. In urban areas, where households have a financial incentive to reduce their fuel purchasing costs, business models without carbon financing may be more viable. While these factors may reduce confidence in the additionality of cook stove projects in urban areas, low income urban households are unlikely to be able to afford more efficient and more costly cook stoves with a payback period of more than a few months.

4.12.4. Baseline emissions

In both types of cook stove projects – improved efficiency and fuel substitution – emission reductions are calculated as the product of the amount of woody biomass saved, the fraction that is considered non-renewable biomass, the net calorific value (NCV) of the biomass, and an emission factor for the fuel used. The net calorific value of the non-renewable biomass ($NCV_{biomass}$) is relatively straightforward – it is empirically measurable and a default value from the Intergovernmental Panel on Climate Change (IPCC) exists. However, Lee et al. (2013) concluded that there is uncertainty in the approaches to estimating the other parameters: biomass fuel consumption (B_y), fraction of non-renewable biomass (f_{NRB}), and emission factors for fuel combustion ($EF_{projected\_fossilfuel}$). A study by Johnson et al. (2010) assessed the relative contributions of these three variables to the overall uncertainty in carbon offset estimation for an improved cook stove project in Mexico and found that fuel consumption (B_y) contributed to 28% of the uncertainty, fraction of non-renewable biomass (f_{NRB}) contributed 47%, and emission factors ($EF_{projected\_fossilfuel}$) accounted for 25%.

The CDM methodology AMS-II.G presents project developers with three options for quantifying biomass fuel savings from improved stoves: the Kitchen Performance Test (KPT), the Water Boiling Test (WBT), and the Controlled Cooking Test (CCT). The WBT and CCT are laboratory-based methods, whereas the **Kitchen Performance Test** is done in the field, and can thus better represent stove users' actual cooking behaviour. The primary advantage of the **Water Boiling Test** is its simplicity and reduced costs; the laboratory-based method is standardized and replicable. However, the laboratory results on stove performance do not necessarily translate to cooking actual meals in households, and thus the accuracy of this method is frequently called into question (Abeliotis & Pakula 2013; Johnson et al. 2007). Meanwhile, the **Controlled Cooking Test** protocol provides a compromise, better representing local cooking while being conducted in a controlled environment. Berrueta et al. (2008), which evaluated the performance of a stove designed primarily for tortilla-making by using all three tests and found that the WBT "gave little indication of the overall performance of the stove in rural communities", while the CCT was somewhat more predictive of the fuel savings found by the KPT (44-65% for CCT vs. 67% for KPT). There may be options for reducing costs associated with the KPT, such as having local NGOs perform the tests rather than hiring expensive international consultants, as well as opportunities to improve the WBT. In recent years, more comprehensive and appropriate testing methods and performance standards are under development through both ANSI and ISO standardisation organisations. The CDM methodology provides default efficiency values for two traditional stove types – a three-stone fire, or a conventional system with no improved combustion – as well as a default efficiency value for devices with improved combustion air supply or flue gas ventilation. Experts interviewed by Lee et al. (2013) noted that these limited defaults do not cover the range of cook stoves in most countries. The CDM Small-Scale Working Group (CDM SSC WG) considered this in the past, but made the determination not to proceed with developing regional default efficiency values for traditional cook stoves because of the huge variability in values among the available data (UNFCCC 2012a). Lee et al. (2013) conclude that although the KPT is more logistically complicated, and time- and resource-intensive, testing stoves outside of a controlled laboratory setting and using a variety of typical cooking activities appears to be an important factor in ensuring accurate and credible results in the baseline or default analysis. Overall, evidence suggests the Water Boiling Test is not an appropriate tool for assessing baseline fuel consumption and should be removed from the CDM methodology. The methodology should require the use of either the Kitchen or Controlled Cooking Tests. AMS-I.E follows a similar approach for calculating baseline emissions from fuel substitution of cook stoves.

The factor f_{NRB} represents the fraction of woody biomass saved by the project activity in year y that can be established as non-renewable biomass and is a key variable in all current cook stove offset methodologies

Based on its definition of renewable biomass (UNFCCC 2006b), the EB has identified several indicators of scarcity to help identify non-renewable biomass. Woody biomass is considered non-renewable if at least two of the following indicators are shown to exist:

- A trend showing an increase in time spent or distance travelled for gathering fuelwood, by users (or fuelwood suppliers) or alternatively, a trend showing an increase in the distance the fuelwood is transported to the project area;
- Survey results, national or local statistics, studies, maps or other sources of information, such as remote-sensing data, that show that carbon stocks are depleting in the project area;

- Increasing trends in fuel wood prices indicating a scarcity of fuel-wood;
- Trends in the types of cooking fuel collected by users that indicate a scarcity of woody biomass (UNFCCC 2011a).

In 2012, the EB issued national default factors for f_{NRB} based on a highly aggregated approach, balancing the mean annual increment in biomass growth (MAI), the annual change in living forest biomass stocks (ΔF) and biomass growth in protected forest areas (UNFCCC 2012a). Under this approach, f_{NRB} values were calculated for nearly 100 countries, based on the total annual national biomass removals minus the portion of demonstrably renewable biomass from growth in protected reserve areas. The large majority (over four-fifths) of default values exceed 80%, with the remainder ranging from 40% to 77%. While Lee et al. (2013) noted that market actors interviewed characterize development of default f_{NRB} values as a 'huge triumph', there was also recognition by market actors and researchers interviewed that national-level forest growth and total forest harvest removal data alone do not necessarily capture the impact of fuelwood harvesting on carbon stocks. First, the approach does not distinguish removals for timber harvesting from those for fuelwood. Furthermore, there is no justification or validation of whether the change in national carbon stocks has any correlation to fuelwood harvesting. Second, according to this method, high values of f_{NRB} are calculated for countries with significant deforestation. However, deforestation could occur in different geographical areas and be driven by entirely other factors than fuel wood collection. In practice, renewable biomass may be extracted both from plantations and natural forests that are not under protection. The MAI approach is better suited to assess the fraction of harvested wood products that are renewable, rather than fuelwood. Using the change in carbon stocks due to harvested wood products has the potential to significantly overestimate the fraction of non-renewable biomass. Estimates published by de Miranda Carneiro et al. (2013), based on the use of a spatially-explicit land use model to examine the availability of fuelwood, suggest default values for f_{NRB} of wood-fuel on the order of 20-30%, much lower than the prior estimates. Bailis et al. (2015) estimate that 27–34% of woodfuel harvested was unsustainable, with large geographic variations, and conclude that cookstove methodologies probably overstate the climate benefits.

Under the CDM methodology AMS-II.G and AMS-I.E, the quantification of project emission reductions relies on the factor $EF_{projected\_fossilfuel}$, representing the fossil fuel emission factor of "substitution fuels likely to be used by similar users". Since emission reductions from the LULUCF sector can only be claimed from afforestation and reforestation under the CDM, the use of fossil fuel emission factors for baseline fuels represents something of a workaround. While the short-term emission reductions actually occur from avoiding the depletion of carbon stocks, such as avoiding deforestation, emission reductions are calculated using fossil fuel emission factors. One possible argument for this approach is that kerosene or LPG cook stoves might be used by the households if they had a higher income. In this regard, the consideration of emissions from fossil fuel based cooking devices might be regarded as a suppressed demand baseline. However, the approach combines the efficiency of fuel-wood cook stoves with the CO_2 emission factor of fossil fuels. This approach has been roundly criticized. Johnson et al. (2010) say it has "no scientific basis, given that wood emits approximately double the CO_2 per unit fuel energy compared to LPG or kerosene thus halving possible offsets from non-renewable harvesting of fuel". One could also argue that it leads to overestimating baseline emissions if one would assume the long-term suppressed demand baseline of using kerosene or LPG cook stoves. By combining the efficiency from inefficient fuel-wood cook stoves with the CO_2 emission factors from fossil fuels, the claimed baseline emissions are higher than if the households would use kerosene or LPG cook stoves. The CDM methodology AMS-II.G. suggests the use of a weighted average value of 81.6 tCO2/TJ[2], representing a mix of 50% coal, 25% kerosene, and 25% LPG. However, no justification for this fuel mix provided. Coal is not commonly used as a cooking fuel for households transitioning from traditional to modern biomass.

LPG is the dominant fossil fuel used in households transitioning to modern energy for household cooking. Assuming that households would use coal vs. LPG overestimates the emissions factor. For example, if we compare the emissions factor if the fuel mix was LPG vs. the current emission factor we find that the emissions are overestimated by 23%. For charcoal production, the simplification is stretched even further beyond reality. The methodologies permit calculating wood use by charcoal stoves by multiplying the charcoal volume by six, following the 1996 IPCC accounting guidelines to estimate total biomass consumed (IPCC/OECD/IEA 1996, p. 1.42). Then baseline emissions are estimated by applying the projected fossil fuel use emissions factor, which in effect assumes that the project displaces fossil fuel use for charcoal production, which likely significantly overestimates the baseline emissions (Lee et al. 2013).

4.12.5. Other issues

Improved cook stove projects are dependent on end users to achieve emission reductions: households must actually use the improved cook stoves instead of their traditional stoves. Carbon finance monitoring requirements include checking the efficiency of the stove and confirming at least every two years that the stove is still in use. Additional stove monitoring of the efficiency and usage rate is required annually or biannually. Monitoring requirements furthermore include sampling and surveying as specified in the applicable offset protocol. This has been a significant challenge. Carbon finance project monitoring requirements further specify that projects must either ensure that the improved stoves completely replace traditional stoves, or else the traditional stoves must be monitored and accounted for under the project calculations for emission reductions. Lambe et al. (2014) found in their review of projects in Kenya and India that this presented several challenges. In Kenya, where the predominant mode of traditional cooking is with a three-stone fire, the study found that many PDDs acknowledged that this form of traditional stove cannot really be removed or destroyed. In India, traditional stoves in several regions are known as chulhas. These stoves often have a religious significance and households often build the stoves themselves from locally available materials such as mud, brick, or cement (Lambe & Atteridge 2012). This form and construction makes it difficult to guarantee that a new chulha will not be made following the destruction of the old one. Lambe et al. (2014) found that many projects required households to destroy these existing cook stoves. In some cases, photographic evidence is used to demonstrate that the existing stoves have been destroyed. However, because of the challenges with removing traditional stoves and the barriers to ensuring adoption and sustained use of improved cook stoves, more often a stacking of stoves and fuels occurs where traditional and improved cook stoves are both used for different types of cooking (Ruiz-Mercado et al. 2011). While the methodologies contain monitoring guidance for adjusting the baseline fuel consumption if the traditional stove continues to be used, this adds further uncertainty to quantification of changes in fuel consumption. Use of temperature sensors to monitor usage of traditional and improved cook stoves have shown promising signs of helping to address this issue, but are not yet in widespread use in carbon market projects (Ruiz-Mercado et al. 2011).

There is a broader concern about crediting emission reductions from displacement of non-renewable biomass since the increased carbon storage from changes in carbon stocks may only lead to temporary reductions. The risk of non-permanence of emission reductions is addressed through appropriate accounting approaches for afforestation, reforestation, and carbon capture and storage project activities, but it is not addressed for improved cook stove project types. Under the CDM, there are projects promoting the use of biomass energy to displace fossil fuel, as well as improved cook stove projects aimed at decreasing biomass energy use. In theory, this does not present a conflict, assuming that biomass power projects are based in regions with increasing or stable carbon stocks and improved cook stove projects are located in regions with declining carbon stocks. However, looking at registered CDM projects there are several examples of provinces in which there are both biomass power and cook stove projects. This means that in the same province, there are simultaneously CDM projects getting credit for increasing the use of biomass, as well as reducing the use of biomass. For example, in the Henei province in China there are 9 biomass energy projects fuelled by agricultural residues (rice husk and other kinds) as well as 4 improved cook stove projects.

4.12.6. Summary of findings

Additio-nality	• CER revenues are insufficient to fully cover project costs, confidence in additionality may be low in urban settings where households are paying for improved stoves at the retail price
Over-crediting	• Uncertainty in some widely used approaches for estimating biomass savings • Significant uncertainty around the fraction of non-renewable biomass values, recent research suggests this parameter may be significantly overestimated. • Emissions intensity factors of fossil fuel likely underestimate emissions relative to wood-fuel used in the baseline. • Emissions factor for suppressed demand use of fossil fuel overestimate emissions; LPG is the appropriate substitute used by similar consumers, including coal and kerosene overestimate emission reductions.
Other issues	• Challenges in ensuring adoption and sustained use of improved cook stoves result can lead to over-crediting if traditional stoves continue to be used. • The use of biomass as a renewable energy sources is inconsistently accounted for under the CDM; the same region can have biomass power projects receiving credit for increasing biomass use and improved cook stove projects receiving credit for decreasing biomass use.

4.12.7. Recommendations for reform of CDM rules

We recommend revising the current methodologies as follows:

- Eliminate the use of the Water Boiling Test as a means of determining baseline emissions.
- Reconsider the use of default f_{NRB} factors based on the MAI approach.
- Revise the emission factor for the substitution of non-renewable biomass by similar consumers to one based solely on LPG.
- Explore options for incorporating temperature sensors in monitoring plans to improve reliable assessment of the adoption and sustained use of improved vs. traditional cook stoves in households.
- Review the use of biomass as an energy source under the CDM to ensure consistent accounting across project types and regions. The f_{NRB} should be considered in improved cook stove projects, as well as modern biomass energy projects to confirm that projects are not contributing to loss of carbon stocks. The CDM EB needs to provide justification for how both biomass energy and improved cook stove projects can be approved within a sub-region.

4.13. Efficient lighting

4.13.1. Overview

For energy efficient lighting, we focus our analysis on the replacement of incandescent electrical bulbs with more efficient electric lighting, such as Compact Fluorescent Lamps (CFLs) or Light Emitting Diode (LED) lamps. This includes all projects registered under AM0046[79] and AMS II.J[80]

[79] Distribution of efficient light bulbs to households --- Version 2.0.
[80] Demand-side activities for efficient lighting technologies --- Version 6.0.

methodologies as well as projects registered under AMS II.C[81] that are labelled as 'lighting' and 'lighting in service' in UNEP DTU (2014).[82] This technology category was a late starter in the CDM – in mid-2010 there were only half a dozen registered projects and 3 registered PoAs. Recent growth in PoAs, particularly with larger PoAs, indicates a higher potential in the future – even beyond the current project activity and PoA pipeline. Energy efficient lighting projects are typically implemented by an entity (often public sector or linked to a utility) that distributes energy efficient lamps for free or for a nominal fee, and collects and disposes of the incandescent bulbs that have been displaced.

4.13.2. Potential CER volume

For CDM project activities, the 40 projects registered by the end of 2013 state that they will produce 1.4 million CERs per year. This would be 10.3 million CERs in the period of 2013 to 2020. However, the issuance success for the largest project activity, which is the only project using the large-scale methodology, amounted to only 12% in the first monitoring period. This could be related to the time required for the CFL distribution programme to reach full scale, however, and does not necessarily mean that other projects will have similar issuance rates (or that this rate will not increase over time). Other projects have been much more successful, but are considerably smaller. Project activities are dominated by a stream of small-scale projects in India and a single large-scale project in Ecuador – the only registered large-scale energy efficient lighting project – which account for almost 80% of the expected CERs. More than 80% of the small-scale projects use AMS II.J, which was designed specifically as a simplified approach to energy efficient lighting.

The largest volume of CERs for energy efficient lighting, however, could come from PoAs. Twenty-six PoAs had been registered for energy efficiency lighting by the end of 2013. Just from the CPAs already included in these registered PoAs as of the end of 2013, the volume of CERs is estimated by the project developers at 3.4 million per year, or two and a half times greater than for project activities. This could continue to grow, given that only four PoAs have more than one CPA. For PoAs, the main players are China, India, Mexico and Pakistan, with South Africa also hosting multiple PoAs (Table 4-10). The four PoAs with more than one CPA have large numbers of CPAs (e.g. 9 to 53). For some PoAs, the CPAs are delineated to have very similar emission reductions in each CPA (e.g. in Mexico, India, Bangladesh).

81 Demand-side energy efficiency activities for specific technologies --- Version 14.0.

82 This excludes one registered PoA under AMS II.C that focuses on street lighting and is labelled as sub-type "Street lighting".

Table 4-10: Number of energy efficient lighting PoAs and CERs by country and methodology

Country	Number of PoAs	Annual CERs (1,000)	CPAs per PoA	Annual CERs/CPA (1,000)	PoAs with >1 CPA
Bangladesh	1	124	9	14	1
China	14	443	1	32	
India	3	1,555	17	30	1
Kenya	1	31	1	31	
Mexico	1	607	25	24	1
Nigeria	1	29	1	29	
Pakistan	1	557	53	11	1
Senegal	1	4	1	4	
South Africa	3	80	1	27	
AMS-II.C.	6	668	5	22	
AMS-II.J.	20	2,762	6	21	
Total	**26**	**3,431**			**4**

Sources: UNEP DTU 2015b

All of the PoAs for lighting efficiency upgrades have moved to the newer methodology AMS II.J rather than AMS II.C (Table 4-10). No new energy efficient lighting PoAs have entered the pipeline since October 2012, and the new project activity pipeline largely stopped in January 2012, with only one new project activity starting validation in 2013 (in The Gambia).

4.13.3. Additionality

Because only one project activity uses the large-scale methodology, this entire technology area essentially uses SSC methodologies and additionality rules. For SSC projects and PoAs, additionality can be determined through several different routes: All SSC projects (or SSC CPAs within PoAs) must refer to the tool for "Demonstration of additionality of small-scale project activities" (Tool21, ver10.0). This includes the choice of using several different barriers to justify additionality (i.e. investment barrier, technology barrier, prevailing practice barrier, or other barriers). In addition, from July 2012, projects comprised entirely of units below 5% of the small-scale CDM threshold (i.e. 3000 MWh savings for energy efficiency) were considered automatically additional without any further justification. This new 'positive list' additionality argument has not been used by CDM project activities but has been used extensively by PoAs, as discussed further below. Most CDM project activities applying the SSC additionality tool cite investment barriers and use simple cost analysis to prove additionality (Table 4-11). This is because the organisations distributing the efficient lamps do not receive the energy savings, so they incur only costs without any revenue (other than a nominal fee from consumers in some cases).[83]

As mentioned above, since July 2012, the tool for additionality of SSC activities has allowed automatic additionality based on a 'unit threshold' described as "project activities solely composed of isolated units where the users of the technology/measure are households or communities or Small and Medium Enterprises (SMEs) and where the size of each unit is no larger than 5% of the small-

[83] The organisations that charge a nominal fee would be receiving less than the wholesale cost of the CFL, so would lose money on each bulb even though there is nominal revenue. In theory, any programme implemented by an electric utility should not be able to use simple cost analysis because the utility has avoided power generation costs (and deferred capital costs) that are a benefit stream to the project. Even where the project is implemented by a utility (e.g. South Africa's Eskom), this is not addressed because the unit threshold positive list is used to justify additionality.

scale CDM thresholds." For energy efficiency, this threshold of 3000 MWh is roughly 46,000 CFLs. All projects and PoAs applying SSC methodologies may use this rule to qualify for automatic additionality.

Table 4-11: Additionality approaches used by efficient lighting CDM project activities

Additionality approach	Number of PAs	Total Annual CERs (1,000)
Investment barrier: Benchmark Analysis	2	71
Investment barrier: Investment Comparison Analysis	2	60
Investment barrier: Simple Cost Analysis	33	1.079
Investment barrier: Other	1	18
Positive list	2	44
Total	**40**	**1.272**

Sources: Authors' own compilation

Lighting PoAs have also made extensive use of this unit threshold for automatic additionality. A report by the UNFCCC Secretariat in mid-2014 (CDM-EB85-AA-A09) found that 28 of the registered lighting-related PoAs at that time had used either micro-scale or unit thresholds to qualify for automatically additionality. As an example, all 12 of the Chinese PoAs registered in December 2012 used the unit threshold for automatic additionality.

As one of the first 'top-down' large-scale methodologies, the EB published an energy efficiency lighting methodology in November 2013, which included a new approach for additionality demonstration:

- In countries with limited or no regulations supporting energy efficient lighting, as evidenced by a UNEP Global Lighting Map[84] survey of regulations and support for energy efficient lighting, CFLs are automatically additional.[85]
- For other countries (i.e. those with more regulatory support), the "Tool for the demonstration and assessment of additionality" must be used, with an investment analysis and common practice analysis. While the investment analysis may still use simple cost analysis (which would mean that almost all projects would be additional), any country with a higher than 20% penetration of CFLs is not additional under the common practice test.

This new approach essentially restricted CFL CDM projects to countries with limited regulatory support or low market penetration. Given that there are no new projects or PoAs entering the pipeline, however, this more recent methodology has not yet had an impact.

In November 2014, AMS II.J was also revised to only allow for automatic additionality for CFLs when there were limited or no regulations to support energy efficient lighting. However, for countries in which there is significant support for energy efficient lighting, the methodology says that additionality should be demonstrated using the latest version of the "Guidelines on the demonstration of additionality of small-scale project activities". This difference is critical, however, because any project participant may simply use the unit threshold in the "Guidelines on the demonstration of

[84] http://map.enlighten-initiative.org/.
[85] Countries coloured red on the map have limited or no support for energy efficient lighting.

additionality of small-scale project activities" to guarantee automatic additionality, whatever the market penetration in the host country.

The main concern with the additionality of energy efficient lighting in the CDM is whether some activities – at least projects involving CFLs and fluorescent tubes – were already common practice at the time of registration and therefore not additional. The use of micro-scale or unit threshold positive lists means that project activities and PoAs do not have to address this common practice issue at all when using the SSC methodologies. In other words, using the SSC methodologies would be a way of circumventing the higher stringency of the new large-scale methodology. Projects could simply define the size of each CPA in a way that they qualify as automatically additional, whatever the regulations and market penetration in the host country. To evaluate the additionality of the existing pipeline, it is useful to consider the two criteria from AM0113 and the revised AMS II.J: regulatory support and market penetration.

According to the 'en.lighten' initiative's Global Lighting Map referenced in the methodologies, regulatory support for efficient lighting is widespread, but varies greatly by country (Figure 4-9). For the countries with the most CDM PoA activity, the level of support is generally strong:

- China has already banned incandescent lighting[86] and implemented large state subsidy programmes since 2006.[87]
- India does not have a ban on incandescent bulbs, but does have awareness-raising programmes, energy service company initiatives, and consumer financing options.
- Pakistan's minimum energy performance standards also still allow incandescent bulbs, but the country has awareness-raising programmes, bulk procurement and tax incentives.
- South Africa has announced that incandescent bulbs will be phased out by 2016[88], and has testing and certification facilities. More importantly, the national utility, Eskom, distributed 30 million free CFLs between 2002 and 2010.[89]
- A regional report for Latin America on the en.lighten initiative's website notes that a Mexican regulation was passed in December 2010 prohibiting the sale of 100 watt and higher incandescent lamps for the residential sector after December 2011, and similar bans for 75 watt as of December 2012 and 40-60 watt as of December 2013.[90] The Mexican PoA was registered in July 2009, which preceded the passing of these regulations.
- In terms of their rating on minimum energy performance standards by the Global Lighting map, all of the countries with PoAs except Kenya and Malawi are orange (some/in progress) or green (advanced). This means that, in terms of the new large-scale methodology (AM0113), projects in all of the countries except Kenya and Malawi would not be automatically additional, but require the use of the additionality tool with investment analysis and the common practice threshold of 20%.

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86 Imports and sales of 100-watt-and-higher incandescent lamps are banned from 1 October 2012, 60-watt-and-above from 1 October 2014, and 15 watts or higher from 1 October 2016 http://www.chinadaily.com.cn/china/2011-11/04/content_14039321.htm.

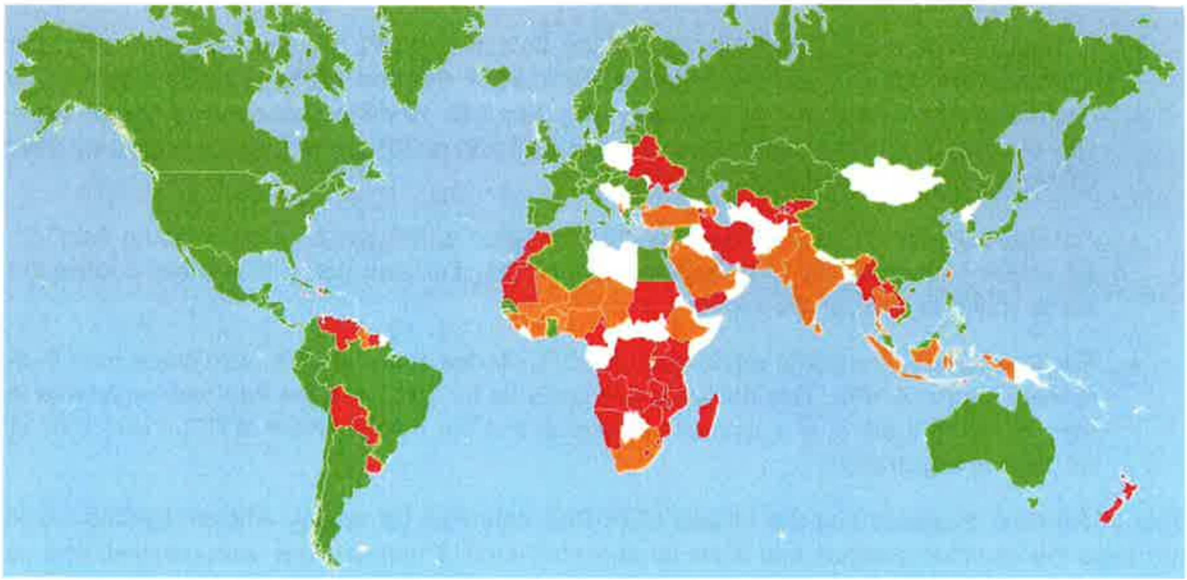
87 http://www.sdpc.gov.cn/zjgx/t20080508_210093.htm.

88 http://www.thegef.org/gef/content/phasing-out-inefficient-lighting-combat-climate-change-south-africa-announces-national-phase.

89 http://www.eskom.co.za/OurCompany/SustainableDevelopment/ClimateChangeCOP17/Documents/The_Eskom_National_Efficient_Lighting_Programme_Compact_Fluorescent_Lamps_Clean_Development_Mechanism_Project.pdf.

90 http://www.enlighten-initiative.org/portals/0/documents/country-support/regional-workshops/Regional%20Report%20LA%20&%20C%20Final%20Eng..pdf. The reference is to regulation "NOM- 028 – ENER – 2010 Energy Efficiency of Lamps for General Use".

Figure 4-9: Minimum energy performance standards for lighting technologies



Notes: Green = Advanced/in place, Orange=In progress, Red=few/limited, white=no information available

Sources: http://map.enlighten-initiative.org/

In terms of assessing common practice, the available evidence suggested that CFLs are likely already common practice in most key CDM countries, and LEDs may be so in the next few years, though not in the poorest countries. The main CDM countries have the following market information:

- According to the "Regional Report on the Transition to Efficient Lighting in South Asia"[91] prepared by the Tata Energy Research Institute in 2014, the market share of CFLs in India amounted to 29% in 2012-2013. Three of the four Indian PoAs were registered in late 2012, while one was registered in early 2010. In addition, for the largest PoA – which was registered in 2010 and has 50 CPAs – the PoA DD states that, "[t]he penetration share of incandescent lamps for lighting in commercial and residential sector put together is thus nearly 80% in India."[92] The market share for CFLs, therefore, was almost certainly above 20% when the PoAs were registered.
- In China, a 2012 McKinsey & Company report estimates the penetration of LEDs (the more expensive alternative to CFLs) as 12% in 2011, rising to 46% by 2016. The report also notes that, "CFL is still the dominant technology in the residential segment."[93] This means that, at the time of registration of the PoAs, the market share of CFLs was almost certainly above 20%. China does not have any LED PoAs yet. If they were proposed, AMS II.J and AM0113 both consider LED lamps automatically additional in all countries until at least the end of 2016. Given the McKinsey projections presented above, automatic additionality for LEDs in China would not be appropriate.

91 http://www.enlighten-initiative.org/Portals/0/documents/country-support/Regional%20Report%20on%20the%20Transition%20to%20Efficient%20Lighting%20in%20South%20Asia.pdf.

92 http://cdm.unfccc.int/ProgrammeOfActivities/gotoPoA?id=CZ59J1XMR8K4ELUS6WY3BA0IVTGQ2F.

93 http://www.mckinsey.com/~/media/mckinsey/dotcom/client_service/automotive%20and%20assembly/lighting_the_way_perspectives_on_global_lighting_market_2012.ashx.

- The large PoA in Mexico states in the PoA DD that CFL penetration in 2007 was already at 20%, while the PoA was registered in June 2009.[94]

- In South Africa, even before the start of the Eskom free CFL distribution programme, the market share of CFLs was estimated at 7% in 2002 (Nkomo 2005). With 30 million CFLs distributed after this time,[95] in a country with less than 10 million households, the penetration of efficient lighting was almost certainly well above 20% when Eskom registered their CDM project activity and PoAs in 2012.

- For Pakistan, the "Regional Report on the Transition to Efficient Lighting in South Asia" cited above estimates the CFL market share at 8%, but also notes that linear fluorescent lamps make up 32% of the market.

- For Bangladesh, the same report puts the CFL market share at 25%, with linear tube fluorescent lamps at 18%. This market share could be for 2013 and the PoA was registered in May 2011, so there is a reasonable likelihood that the market share of CFLs was 20% at the time of registration.

This information suggests that the largest CDM PoA countries for energy efficient lighting would not pass the common practice test if the large-scale AM0013 methodology were applied, and so these PoAs would not qualify as additional. Bangladesh, China, India, South Africa and Mexico account for almost 80% of the expected CERs from PoAs, and yet these countries were likely above the 20% market share for CFLs when the PoAs were registered.

For off-grid lighting (AMS III.AR), the situation is quite different. Access to electricity in rural households in Sub-Saharan Africa, for example, is less than 10% (IEA et al. 2010; Legros et al. 2009). Between 2010 and 2015, the estimated number of unelectrified households in Africa was estimated to grow from 110 million to 120 million (Dalberg Global Development Adv. 2010) . The off-grid solar lamp market is expanding to address the 1.5 billion people who do not (and, in many cases, will not) have access to electricity (IFC 2012). While solar lantern and solar kit prices are decreasing, they still face major barriers in terms of distribution challenge, upfront costs (and lack of consumer financing), and successful business models for scaling up (ESMAP 2013; IFC 2012).

Assessing the economics of energy efficient lighting faces the classic problem of 'split incentives' (Spalding-Fecher et al. 2004). From an economic point of view, upgrades to energy efficient electric lighting are unquestionably economically beneficial (i.e. have large positive IRRs) (McKinsey & Company 2009) but the benefits do not accrue to those who pay for the additional costs if the project is funded by outside agencies. The economics of efficient lighting are more likely to be driven by electricity prices than carbon prices. For example, a 15 W CFL replacing a 60W incandescent lamp operated 3.5 hours per day could save 57 kWh per year. With a relatively carbon-intensive grid (e.g. 0.8 tCO_2/MWh), this would be 0.05 tCO_2e savings per year. Electricity prices to the consumer in developing countries vary widely, from $50/MWh in heavily subsidized economies to more than $170/MWh in more competitive emerging economies (EIA 2010; Winkler et al. 2011). This means an energy savings of $2.87 to $9.77/year. CFL costs have also declined rapidly, with current costs of $1.50-$2.50 in many countries (UNEP 2012). This would mean a typical payback period of much less than one year, before any carbon revenue was received. At current CER prices, carbon revenue would be less than two cents per year only, while at $3-5/CER, revenue would be $0.15-0.25, or less than 5% of energy savings.

[94] http://cdm.unfccc.int/ProgrammeOfActivities/poa_db/17BH6AJX524TYQUZF8KGCWV3OIPSE9/view Annex 3.

[95] http://www.eskom.co.za/OurCompany/SustainableDevelopment/ClimateChangeCOP17/Documents/The_Eskom_National_Efficient_Lighting_Programme_Compact_Fluorescent_Lamps_Clean_Development_Mechanism_Project.pdf.

In summary, CDM rules on additionality of efficient lighting projects vary considerably. Using market penetration and regulatory support as indicators for the likelihood seems a reasonable approach. The large-scale AM0113 methodology uses market penetration and regulatory support as indicators for demonstrating additionality; this approach seems reasonable and reflects the varying circumstances of host countries. AM0046 may provide for a suitable alternative by monitoring the market penetration of CFLs and LEDs in a control group outside the project boundary; however, the complexity and cost of monitoring under this methodology means that only one project has even chosen to utilise it – so the additionality approaches may not be relevant for the overall impact of this project category. In contrast, under small-scale methodologies, including the revised AMS II.J, this project type is, in practice, considered automatically additional, even if the use of CFLs is required by regulations and is widespread. However, for countries with regulations that have phased out incandescent bulbs or large subsidy programmes for CFLs, these existing registered projects are unlikely to be additional. If we take the 20% market share used in AM0113 as the point at which CFL programmes are no longer likely to be additional, then this would apply to most of the current CDM pipeline for energy efficient lighting.

4.13.4. Baseline emissions

In AMS II.J, AM0113 and AMS II.C (when used for lighting) the baseline is simply the use of the existing incandescent lamps – those which are collected and replaced within the project boundary.[96] Both AMS II.J and AM0113 take similar approaches, where emissions reductions are related to the difference in power between a CFL and baseline bulb, operating hours, lamp failure rates, a 'net-to-gross' adjustment, and the grid emissions factor (taking technical losses into account).[97] As a default, 3.5 operating hours per day are assumed. If project participants want to use operating hours greater than 3.5 per day, they must conduct a once-off survey at the start of the project to justify this. The lamp failure rates are also based on periodic surveys of the first group of bulbs installed, up to the end of their rated life. The methodologies require project participants to explain how they will collect and destroy baseline lamps. For off-grid lighting, an innovative 'deemed consumption' approach assigns a standard emissions reduction to each off-grid lighting unit, based on the fossil fuel alternative. The parameters and assumptions are conservative. Overall, the approaches to baseline emissions for efficient lighting are straightforward and conservative, and the improvements over the last two years have also simplified or clarified many of the sampling procedures.

4.13.5. Other issues

At 3-5 hours of use per day, a typical CFL would last anywhere from 3 to 10 years. This means that a crediting period of 10 years is almost certainly too long, unless the CDM project guarantees free replacements throughout the programme or restricts crediting to the measured life. The latter approach has been adopted under the CDM. Emission reductions do not accrue once the lamp failure rate reaches 100%, so if all lamps fail before the end of the crediting period and are not replaced, then no CERs would be issued. These provisions seem appropriate.

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96 AM46 also includes the possibility of some efficient lighting in the baseline, as a form of "autonomous efficiency improvement", but this methodology has only been used once and is unlikely to be used in the future.

97 AMS II.C is not so specific, because the guidance was for all energy efficiency technologies, but the approach elaborated by the project participant would essentially be the same.

4.13.6. Summary of findings

Additio-nality	• Granting automatic additionality under small-scale methodologies to all energy efficient lighting programmes in the past was highly problematic because there were large PoAs in countries in which the move away from incandescent bulbs was well underway; the new large-scale AM0113 methodology appropriately addresses these problems but is not mandatory, while the remaining small-scale methodology could still allow for automatic additionality for CFL programmes, so it is unlikely that the large-scale methodology will be used. • In many countries with lower income or less regulatory support, however, efficient lighting still faces major barriers, even if it is potentially economic beneficial, and so projects may need the support of the CDM to be implemented; these projects currently form a very small part of the project pipeline but could grow in the future.
Over-crediting	• Over-crediting is unlikely, given the robust monitoring procedures.
Other issues	• None

4.13.7. Recommendations for reform of CDM rules

AMS II.J should be revised so that CFL programmes in countries with significant regulatory support may use the tool for "Demonstration of additionality of small-scale project activities" but may not use the paragraph referring to automatic additionality based on small unit size.

5. How additional is the CDM?

Based on the detailed analysis of individual project types in the previous chapter, this chapter provides an overall assessment of the environmental integrity of the CDM project portfolio available for the second commitment period of the Kyoto Protocol. Table 5-1 provides an overview of the summary of findings for each of the analyzed project types.

Table 5-1: Evaluation of project types

Project type	Additionality [1)]	Over-crediting [2)]	Other issues	Overall environmental integrity [3)]
HFC-23 (up to version 5)	• Likely to be additional	• Risk of perverse incentives	• None	Medium
HFC-23 (version 6)	• Likely to be additional	• Risk of perverse incentives largely addressed • Ambitious baseline could lead to under-crediting (net mitigation benefit)	• Low CER prices could jeopardize continued operation • Emissions could be addressed through Montreal Protocol	High
Adipic acid	• Likely to be additional	• Most recent methodology could lead to slight under-crediting • Leakage could lead to significant over-crediting in times of higher CER prices	• None	Medium
Nitric acid	• Likely to be additional	• Most recent methodologies lead to under-crediting • Overall, little risks of overall over-crediting	• None	High
Wind power	• CER revenue has only limited impact on profitablity • Investment costs decreased significantly in last years • In some cases competitive with fossil generation • Support schemes • Widespread in many countries	• Methodological assumptions may lead to both over- and under-crediting	• None	Low
Hydro power	• Common practice in many countries • CERs have only moderate impact on profitablity • Competitive with fossil generation in many cases	• Methodological assumptions may lead to both over- and under-crediting; over the lifetime of the project likely under-crediting	• Methane emissions from reservoirs may be important and may not be fully reflected by CDM methodologies	Low
Biomass power	• Significant impact of CER revenues on profitability for projects claiming methane avoidance • Competitive with fossil generation in many cases • Support schemes	• Demonstration of biomass decay/abundance of biomass is key • Risk of exaggerated claims of anaerobic decay	• None	Medium

Project type	Additionality [1)]	Over-crediting [2)]	Other issues	Overall environmental integrity [3)]
Landfill gas	• Likely to be additional	• Default assumptions for the rate of methane captured historically have the potential to overestimate emission reductions • Default soil oxidation rates may underestimate emission reductions for uncovered landfills in humid subtropical and tropical regions • Perverse incentives for project developers to increase methane generation	• Perverse incentives for policy makers not to pursue less GHG intensive waste treatment methods	Medium
Coal mine methane	• Likely to be additional	• Potential concerns regarding increased mining	• Potential perverse incentives to dilute methane in order to avoid that abatement is required by regulations	Medium
Waste heat recovery	• CER revenues small compared to fossil fuel cost savings • Future fuel cost savings uncertain • Widespread in many countries	• Brownfield: risks for inflated baselines • Greenfield: modelling uncertain • Plant operation under the project different to baseline	• None	Low
Fossil fuel switch	• Use of barrier analysis allowed for small-sclae projects not appropriate • Investment analysis insufficient as choice of fuel depends not only on prices • CER revenues have a small impact	• Default values for upstream emissions not appropriate	• None	Low

Project type	Additionality [1)]	Over-crediting [2)]	Other issues	Overall environmental integrity [3)]
Efficient cook stoves	• CER revenues are insufficient to fully cover project costs • Additionality questionable in urban areas	• Fraction of NRB likely to be overestimated • Water boiling test not appropriate • Emission intensity factors of fossil fuel likely underestimate emissions relative to wood-fuel used in the baseline • Emissions factors used for suppressed demand are unrealistic • Unrealistic assumptions for charcoal use • Over-crediting if traditional stoves continue to be used	• Inconsistent accounting: CDM credits in the same region both reduction and increase of biomass use	Low
Efficient lighting (AMS II.C AMS II.J)	• Shift to EE lighting well underway and/or mandates in most common PoA countries, and PoAs allowed to use SSC additionality 'loophole'	• Unlikely	• None	Low
Efficient lighting (AM0113, AM0046)	• Likely to be additional	• Unlikely	• None	High

Notes: [1)] High/medium/low likelihood of projects being additional under current rules; [2)] High/medium/low likelihood of avoiding over-crediting under current rules; [3)] High/medium/low likelihood of emission reductions being additional and not over-credited under current rules.

Sources: Authors' own compilation

Overall, the table shows considerable differences between project types. Most energy-related project types (wind, hydro, waste heat recovery, fossil fuel switch and efficient lighting) are unlikely to be additional, irrespectively of whether they involve the increase of renewable energy, efficiency improvements or fossil fuel switch. An important reason that these projects types are unlikely to be additional is that for them the revenue from the CDM is small compared to the investment costs and other cost or revenue streams, even if the CER prices would be much higher than today. In addition, technological progress was much faster than expected, so that investment and generation costs have fallen considerably. Moreover, some project types are, in many instances, economically attractive (e.g. waste heat recovery, fossil fuel switch, hydropower), or supported through policies (e.g. wind power, efficient lighting), or mandatory due to regulations (e.g. efficient lighting). Some of these project types also have a medium likelihood of overestimating emission reductions, mainly due to risks of inflated baselines.

Industrial gas projects (HFC-23, adipic acid, nitric acid) can generally be considered likely to be additional as long as they are not promoted or mandated through policies. They use end-of-pipe-technology to abate emissions and thus do not generate revenues other than CERs. HFC-23 and adipic acid projects triggered strong criticism because of their relatively low abatement costs, which provided perverse incentives and generated huge profits for plant operators. In the case of HFC-

23, perverse incentives were addressed with the adoption of version 6 of AM0001, which uses an ambitious baseline that could lead to a net mitigation benefit. Similarly, concerns with perverse incentives for nitric acid plant operators not to use less GHG-intensive technologies were addressed. With regard to adipic acid projects, the risks of carbon leakage were not addressed.

Methane projects (landfill gas, coal mine methane) also have a high likelihood of being additional. This is mainly because carbon revenues have, due to the GWP of methane, a relatively large impact on the profitability of these project types. However, both project types face issues with regard to baseline emissions and perverse incentives and may thus lead to over-crediting.

Biomass power projects have a medium likelihood of being additional since their additionality very much depends on the local conditions of individual projects. In some cases, biomass power can already be competitive with fossil generation while in other cases domestic support schemes provide incentives for increased use of biomass in electricity generation. However, where these conditions are not prevalent, projects can be additional, particularly if CER revenues for methane avoidance can be claimed. Biomass projects also face other issues, in particular with regard to demonstrating that the biomass used is renewable.

The additionality efficient lighting project using small-scale methodologies is highly problematic because there were large PoAs in countries in which the move away from incandescent bulbs was well underway. The new methodologies address these problems but they are not mandatory and the small-scale methodologies are while the remaining small-scale methodology could still allow for automatic additionality for CFL programmes.

For cook stove projects, CDM revenues are often insufficient to cover the project costs and to make the project economically viable. In urban areas, however, the additionality of these project types is questionable. Cook stove projects are also likely considerably over-estimate the emission reductions due to a number of unrealistic assumptions and default values.

Based on these considerations we can estimate to which extent the CDM is likely to deliver additional emission reductions during the period of 2013 to 2020 (Table 5-2).

Table 5-2: How additional is the CDM?

	CDM projects			Potential CER supply 2013 to 2020		
	Low	Medium	High	Low	Medium	High
	… likelihood of emission reductions being real, measurable, additional					
	No. of projects			Mt CO_2e		
HFC-23 abatement from HCFC-22 production						
Version <6		5			191	
Verson >5			14			184
Adipic acid		4			257	
Nitric acid			97			175
Wind power	2.362			1.397		
Hydro power	2.010			1.669		
Biomass power		342			162	
Landfill gas		284			163	
Coal mine methane		83			170	
Waste heat recovery	277			222		
Fossil fuel switch	96			232		
Cook stoves	38			2		
Efficient lighting						
AMS II.C, AMS II.J	43			4		
AM0046, AM0113			0			0
Total	4.826	718	111	3.527	943	359

Sources: Authors' own calculations

Our analysis covers three quarters (76%) of the CDM projects and 85% of the potential CER supply during that period. 85% of the covered projects and 73% of the potential CER supply have a low likelihood of ensuring environmental integrity (i.e. ensuring that emission reductions are additional and not over-estimated). Only 2% of the projects and 7% of potential CER supply have a high likelihood of ensuring environmental integrity. The remainder, 13% of the projects and 20% of the potential CER supply, involve a medium likelihood of ensuring environmental integrity.

Has the performance of the CDM in terms of additionality improved over time? Several EB decisions have certainly improved the performance, particularly those which introduced ambitious baselines and/or addressed perverse incentives. However, Schneider (2007) estimated, "that additionality is unlikely or questionable for roughly 40% of the registered projects. These projects are expected to generate about 20% of the CERs". Schneider's methodological approach is not identical with the approach applied in this study but is, nevertheless, similar enough for a comparison of the overall results. Compared to earlier assessments of the environmental integrity of the CDM, our analysis suggests that the CDM's performance as a whole has anything but improved, despite improvements of a number of CDM standards. There are several reasons for this:

- The main reason is a shift in the project portfolio towards projects with more questionable additionality. In 2007, CERs from projects that do not have revenues other than CERs made up about two third of the project portfolio, whereas the 2013-2020 CER supply potential from these project types is only less than a quarter. This is mainly due the registration of many energy projects between 2011 and 2013, including both fossil and renewable projects, which represent the largest share of CDM projects and of potential CER supply today, many of which are unlikely to be additional. It can therefore be questioned whether the CDM is the appropriate incentive scheme for those project types, or more generally, whether these project types are appropriate for crediting schemes at all.

- A second reason is that the CDM EB not only improved rules but also made simplifications that undermined the integrity. For example, positive lists were introduced for many technologies, for some of which the additionality is questionable and some of which are promoted or required by policies and regulations in some regions (e.g. efficient lighting). Another example is biomass residue projects, for which requirements to demonstrate that the biomass is available in abundance were strongly simplified, making an over-estimation of emission reductions more likely.
- A third reason is that the CDM EB did not take effective steps to exclude project types with a low likelihood of additionality. While positive lists were introduced, project types with more questionable additionality were not excluded from the CDM. The common practice test is not effective as it stands. Standardized baselines can be optionally used as an alternative to project-specific baselines, which provides a further avenue for demonstrating additionality but does not reduce the number of projects wrongly claiming additionality. In conclusion, the improvements to the CDM mainly aimed at simplifying requirements and reducing the number of false negatives (projects that are additional but do not qualify under the CDM) but did not address the false positives (projects that are not additional but qualify under the CDM).

Our analysis of the environmental integrity of the CDM has focused on the quality of CERs in terms of ensuring emission reductions that are additional and not over-credited. The overall environmental outcome of the CDM is, however, also influenced by several overarching and indirect effects:

- **Awareness raising and capacity building**: The CDM has drawn attention to climate change and to options of how it can be mitigated and thus contributed to the issue of climate change being better understood and taken more seriously in many parts of the world. In this way it has helped to pave the way towards the global agreement achieved at COP 21 in Paris in December 2015.
- **Technological innovation**: The CDM has helped to spread and reduce costs of many GHG mitigation technologies such as renewable energy technologies or technologies to avoid methane emissions in many developing countries. This may have helped developing countries to avoid locking in carbon-intensive technologies. The increased application of these technologies has contributed to reducing their total cost, and the CDM has contributed to building the capacity on how these technologies can domestically be applied in many developing countries.
- **Length of crediting periods:** Certain projects may continue their operation beyond their crediting period and will not receive credits for the respective GHG reductions. This effect has been estimated to have a significant potential for under-crediting (Spalding-Fecher et al. 2012). However, over time the respective technologies often become economically viable without support and thus the common practice in many circumstances. The CDM may thus have contributed to advancing an investment, which would anyhow be conducted some years later, so that even the additionality of CERs generated in the late years of a crediting period could be questioned.
- **Rebound effects:** For CDM project developers and host countries, CER revenues are similar to subsidies, which often lower the cost of the product or service provided (e.g. electricity, cement, transportation), thereby inducing greater demand for the product or service. In contrast, carbon taxes or auctioning of allowances under the ETS generally provide incentives to reduce the demand for products or services. Calvin et al. (2015) show that ignoring such system-wide rebound effects in the power sector can lead to significant over-

crediting compared to the actual reductions at system level. The overall mitigation outcome of crediting could be systematically over-estimated, even if projects are fully additional and the direct GHG emission impact of a project is quantified appropriately. This is mainly because credits subsidize the deployment of technologies with lower emissions instead of penalising the use of more emitting technologies and because CDM methodologies draw the boundary around a project and do not consider the wider rebound effects.

- **Perverse policy incentives:** In some instances, the CDM may provide an incentive to governments not to implement domestic policies to address emissions. For example, policy makers may have disincentives to introduce regulations requiring the capture of landfill gas or to further pursue landfilling instead of less GHG-intensive waste treatment methods, since they would otherwise lose revenues from CERs.

All these effects somehow influence the environmental outcome of the CDM, partly for the better and partly for the worse. The overall effect can hardly be determined. However, it is unlikely that these overarching and indirect effects fully compensate for the overall low environmental integrity of many projects and CERs. On the contrary, in a forward-looking perspective, comparing the situation in which the CDM continues to be used with a situation in which this would not be the case, it is rather likely that these overarching effects further undermine the environmental outcome of the CDM overall.

The result of our analysis suggests that the CDM still has fundamental flaws in terms of environmental integrity. It is likely that the large majority of the projects registered and CERs issued under the CDM are not providing real, measureable and additional emission reductions. Therefore, the experiences gathered so far with the CDM should be used to improve both the CDM rules for the remaining years and to avoid flaws in the design of new market mechanisms being established under the UNFCCC. In the following chapters we summarise how the existing CDM should be improved (Chapter 6) and what can be learned from the CDM experience for the future of market mechanisms in general (Chapter 7).

6. Summary of recommendations for further reform of the CDM

The recommendations for the further reform of the CDM can be distinguished according to improvements of the general rules and approaches how to determine additionality and to project type-related recommendations.

6.1. General rules and approaches for determining additionality

As mentioned above, for an additionality test to function effectively, it must be able to assess, with high confidence, whether the CDM was the deciding factor for the project investment. However, additionality tests can never fully avoid wrong conclusions. They cannot fully reflect the complexity of investment decisions. Additionality tests always look at part of the full picture and use simplified indicators, such as economic performance or market penetration, to make a judgment on whether or not a project is truly additional. Information asymmetry between project developers and regulators, combined with the economic incentives for project developers to qualify their project as additional, are a major challenge. The key policy question is how confident regulators should be that a project is additional. In other words, how should the number of false positives (projects that qualify as additional but are not) and false negatives (projects that are additional but do not pass the test) be balanced? We assessed the current additionality tests from the perspective that a high degree of confidence is required. The main reason is that the implications of false positives are much more severe than the implications of false negatives. A false positive leads to both an increase in global

GHG emissions and higher global costs of mitigating climate change, whereas a false negative does not affect global GHG emissions but only leads to higher costs of mitigating climate change (Schneider et al. 2014).

In Chapter 3 we thoroughly scrutinised the four main approaches used to determine additionality. Our analysis shows:

- **Prior consideration** is a necessary and important but insufficient step for ensuring additionality of CDM projects. This step works largely as intended (Section 3.1.4).
- The subjective nature of the **investment analysis** limits its ability to assess with high confidence whether a project is additional. It is possible that improvements could further decrease this subjectivity, e.g. by applying more complicated tests to assess the financial performance of the project. However, especially for project types in which the financial impact of CERs is relatively small compared to variations in other parameters such as large power projects, doubts remain as to whether investment analysis can provide a strong 'signal to noise' ratio (Section 3.2.4).
- To reduce the subjectivity of the **barrier analysis**, the *'Guidelines for objective demonstration and assessment of barriers'* require that barriers are monetized to the extent possible and integrated in the investment analysis. As a result of this, the barrier analysis has lost importance as a stand-alone approach of demonstrating additionality. However, barriers which are not monetized remain subjective and often difficult to verify by the DOEs (Section 3.4.4).
- In general, the **common practice analysis** can be considered a more objective approach than the barriers or investment analysis due to the fact that information on the sector as a whole is considered rather than specific information of a project only. It reduces the information asymmetry inherent in the investment and barrier analysis (Section 3.3.4). In this regard, expanding the use of common practice analysis could be a reasonable approach to assessing additionality more objectively. However, the presented analysis shows that the way common practice is currently assessed needs to be substantially reformed to provide a reasonable means of demonstrating additionality. Moreover, when expanding its use, it is important to reflect that market penetration is not a good proxy for all project types for the likelihood of additionality. The fact that few others have implemented the same project type is only an indication of the actual attractiveness. It should thus be only applied to those project types for which market penetration is a reasonable indicator.

Against this background we recommend that

- the **prior consideration** grace period for notification after the start of a CDM project should be shortened from 180 to 30 days to reduce the risk that projects apply for the CDM having only learned about this option after the start of the project,
- the **common practice analysis** is significantly reformed and receives a more prominent role in additionality determination,
- the **investment analysis** is excluded as an approach for demonstrating additionality for projects types for which the 'signal to noise' ratio is insufficient to determine additionality with the required confidence; while for those project types for which investment analysis would still be eligible, project participants must confirm that all information is true and accurate and that the investment analysis is consistent with the one presented to debt or equity funders, and

- the **barrier analysis** is entirely abolished as a separate approach in the determination of additionality at project level (though it may be used for determining additionality of project types); barriers which can be monetized should be addressed in the investment analysis while all other barriers should be addressed in the context of the reformed common practice analysis.

A prerequisite for expanding the use of the common practice analysis is significant improvements of its current shortcomings, most notably with regard to the following issues (Section 3.3.4):

- The project types and sectors covered by the CDM are very different in their technological and market structure. Determining what is deemed to be common practice must take into account these differences. Therefore, the 'one-size-fits-all' approach of determining common practice should be abandoned and be replaced by **sector or project-type specific guidance**, particularly with regard to distinguishing between different and similar technologies (appropriate level of dis-/aggregation) and with regard to the threshold for market penetration, which can have very different implications for the number of projects passing the test, depending on the features of the sectors or project types.

- The **technological potential** of a certain technology should also be taken into account in order to avoid that a project is deemed additional although the technological potential is already largely exploited in the respective country. However, results of studies on the technological potential depend strongly on their assumptions and may thus vary significantly. The exploitation rate should therefore only be considered one criterion among others in determining whether a technology is common practice; it should not form the only decisive criterion.

- The common practice analysis should at least cover the **entire country**. However, to ensure statistical confidence, the control group needs a minimum absolute number of activities or installations. If the observations in the host country do not exceed that minimum threshold, the scope needs to be extended to other countries (e.g. the neighbouring countries or the entire continent).

- Last but not least, all CDM projects should be included into the common practice analysis as a default, unless a methodology includes different requirements.

In addition to the above-mentioned improvements of general approaches for determining additionality, we recommend further improvements to key general CDM rules:

- **Renewal and length of crediting periods:** At the renewal of the crediting period, not merely the validity of the baseline but the validity of the baseline scenario should be assessed for CDM projects that are potentially problematic in this regard. This is the case if the baseline is the 'continuation of the current practice' or if changes such as retrofits could also be implemented in the baseline scenario at a later stage. Crediting periods of project types or sectors that are highly dynamic or complex such as urban transport systems or data centres should be limited to one single period of 10 years maximum. Moreover, generally abolishing the renewal of crediting periods but allowing a somewhat longer single crediting period for project types which require a continuous stream of CER revenues to continue operation (e.g. landfill gas flaring) may also be considered (Section 3.5.4).

- **Positive Lists:** Some of the positive lists are now reviewed regularly, and have a clear basis for determining whether a technology should still be included in the lists. This review of validity should also be extended to project types covered by the microscale additionality tool. In addition, positive lists must address the impact of national policies and measures to support low emissions technologies (so-called E- policies). For positive lists to avoid the possibility of 'false positives' driven by national policies, some objective measure of renewable energy support may be needed as part of the evaluation process. A positive list that included renewables, for example, could be qualified by restricting its applicability to countries that did not have any support policies in place for that specific technology. Finally, to maintain environmental integrity of the CDM overall, positive lists should be accompanied by negative lists (Section 3.7).

- **Programmes of activities:** PoA rules allow that the total project size exceeds the small-scale or micro-scale thresholds while using the automatic additionality provision established for small-scale and micro-scale projects. This may increase the risk of registering non-additional projects. Reform of the CDM rules related to additionality for particular project types (Chapter 4) and positive lists (Section 3.7) will address any concerns about additionality of PoAs (Section 3.6.3). However, as long as these rules are not reformed accordingly, PoA have the potential to boost the number of non-additional project activities and CERs.

- **Standardized baselines:** These were introduced to reduce transaction costs while ensuring environmental integrity. In contrast to the general expectation, they do not increase the environmental integrity of the CDM. On the contrary, as long as they are not mandatory, once established, they lower the environmental integrity because they allow for increasing the number false positive projects. Therefore, their use should be made mandatory. Moreover, all CDM facilities should be included in the peer group used for the establishment of standardized baselines and clearer guidance needs to be provided for DNAs on how to determine the appropriate level for disaggregation. Finally, the practice of using the same methodological approach for the establishment of standardized baselines for all sectors, project types and locations should be abolished (Section 3.8).

- **Consideration of domestic policies (E+/E-):** The risk of undermining environmental integrity through over-crediting of emission reductions is likely to be larger than the creation of perverse incentives for not establishing E- policies. Therefore, adopted policies and regulations reducing GHG emissions (E-) should be included when setting or reviewing crediting baselines while policies that increase GHG emissions (E+) should be discouraged by their exclusion from the crediting baseline where possible (Section 3.9).

- **Suppressed demand:** In many cases, the Minimum Service Levels may be reached during the lifetime of CDM project. However, even if the suppressed demand does lead to some over-crediting, the overall impact is very small. An expert process should be established to balance the risks of over-crediting with the potential increased development benefits. In addition, the application of suppressed demand principles in methodologies could be restricted to countries in which development needs are highest and the potential for over-crediting is the smallest, such as LDCs (Section 3.10).

6.2. Project types

We note that even with 'perfect' rules for determining additionality as recommended in Section 6.1, many project types have fundamental problems with this determination. Drawing upon our findings for specific project types (Section 4), this section provides recommendations of which project types should remain eligible in the CDM. In doing so, we not only consider the environmental integrity under current rules, but also whether improvements of general or project type-specific rules could be implemented to ensure overall environmental integrity. We also include other considerations, such as whether the emission sources can be addressed more effectively by other policies.

Industrial gas projects: In contrast to conventional wisdom and their perception in the general public, our analysis shows that industrial gas projects provide for a high or medium environmental integrity. After issues related to perverse incentives have been successfully addressed through ambitious benchmarks, **HFC-23** and **nitric acid** projects now provide for a high degree of environmental integrity. They are very likely to be additional because they involve so-called 'end-of-the-pipe' technologies and do not have significant income other than CERs and because revenues from CERs have a large impact on the economic feasibility. Moreover, they partially use emission benchmarks as baselines which underestimate the actual emission reductions. The methodologies for HFC-23 and nitric acid projects have already been improved in the past and do not require further improvements (Sections 4.2.7 and 4.4.7). For **adipic acid**, the situation is different; this project type is also likely to be additional but concerns about carbon leakage due to high CER revenues have never been addressed. Adipic acid production is a highly globalised industry and all plants are very similar in structure and technology. A global benchmark of 30 kg/t applied to all plants would prevent carbon leakage, considerably reduce rents for plant operators, and allow the methodology to be simplified by eliminating the calculation of the N_2O formation rate (Section 4.3.7). Industrial gas projects provide for low cost mitigation options. Under current rules, HFC-23 and adipic acid projects may generate large rents for plant operators. These emission sources could therefore also be addressed through domestic policies, such as regulations or by including the emission sources in domestic or regional ETS, and help countries achieve their NDCs under the Paris Agreement. For example, China is introducing a domestic results-based finance policy aiming at incentivising HFC-23 emissions reductions. Parties to the Montreal Protocol also consider regulating HFC emissions. We therefore recommend that HFC-23 projects are not eligible under the CDM. A transition to address these emissions domestically may also be supported by bilateral or multilateral initiatives of (results-based) carbon finance.

Energy-related project types: Our analysis suggests that many energy-related project types provide for a low likelihood of overall environmental integrity, particularly **wind and hydropower** (Sections 4.5.7 and 4.6.7), **fossil fuel switch** (Section 4.11.7) and **supply-side energy efficiency project** types such as **waste heat recovery** (Section 4.10.7). The main reason for this assessment is that CER benefits are often relatively small compared to fuel cost savings, so that the impact of CER revenues on the economic feasibility is marginal (Section 2.4). Many projects are also supported through other policies, such as feed-in tariffs for renewable electricity or emerging ETSs. The costs for renewable power technologies are decreasing rapidly. In our assessment, the potential for addressing additionality concerns through improved tests are rather limited for these project types. Many projects are economically viable and even an improved investment analysis or common practice test may not be suitable to clearly distinguish additional from non-additional projects. We therefore recommend **that these project types should be no longer eligible in principle** under the CDM. However, in least developed countries, some project types, particularly wind and small-scale hydropower plants, may still face considerable technological and/or cost barriers (Section 4.5.3). These project types may thus remain eligible in least developed countries.

We recommend that some other energy-related project remain eligible if methodologies are improved. **Biomass power projects** can be competitive with fossil generation technologies under certain but not all circumstances. In cases in which power generation from biomass is not competitive with fossil generation technologies, CER revenues can have a significant impact on the profitability of a project, particularly if credits for methane avoidance are claimed as well. In these cases, the demonstration of abundance of biomass as well as of the claim that biomass is left to decay is key for avoiding any over-crediting of emissions. We therefore recommend that only biomass power projects avoiding methane emissions remain eligible under the CDM provided that the corresponding provisions in the applicable methodologies are revised appropriately (Section 4.7.7).

With regard **demand-side energy efficiency** project types with distributed sources **– cook stoves** and **efficient lighting** – we have identified concerns which question their overall environmental integrity. However, environmental integrity concerns could be addressed if cook stove methodologies were revised considerably, including more appropriate values for the fraction of non-renewable biomass (Section 4.12.7), and if approaches for determining the penetration rate of efficient lighting technologies as already established in AM0113 were made mandatory for all new projects and CPAs under these project types and the older methodologies were withdrawn (Section 4.13.7). As CER revenues can have a considerable impact and as barriers persist these projects, we recommend that they should remain eligible, subject to the improvements recommended.

Methane projects: Landfill gas and **coal mine methane** projects are likely to be additional. However, there are concerns in terms of over-crediting, which should be addressed through improvements of the respective methodologies, particularly by introducing region-specific soil oxidations factors and by requesting DOEs to verify that landfilling practices are not changed (Sections 4.8.7 and 4.9.7). For both project types, the CER revenues have a considerable impact on their economic performance. With regard to landfill gas, an important concern is that continued incentives for landfilling could delay the implementation of more sustainable waste management practices, such as recycling or compositing. We therefore recommend that this project type only be eligible in countries that have policies in place to transition to more sustainable waste management practices.

Table 6-1 summarises our recommendations for the specific project types assessed above.

Table 6-1: CDM eligibility of project types

Project type	Environmental integrity under current rules	Environmental integrity if rules were improved	Recommendations
HFC-23	Medium / High	High	Not eligible
Adipic acid	Medium	High	Eligible (with benchmark of 30 kg / t AA)
Nitric acid	High	High	Eligible
Wind power	Low	Low	Not eligible
Hydropower	Low	Low	Not eligible
Biomass power	Medium	Medium / High	Eligible (projects avoiding methane emissions)
Landfill gas	Medium	Medium / High	Eligible (subject to transition arrangements)
Coal mine methane	Medium	Medium / High	Eligible
Waste heat recovery	Low	Low	Not eligible
Fossil fuel switch	Low	Low	Not eligible
Efficient cook stoves	Low	Medium / High	Eligible
Efficient lighting	Low / High	Medium / High	Eligible

Sources: Authors' own compilation

7. Implications for the future role of the CDM and crediting mechanisms

In this section, we consider the implications of our analysis for the future role of the CDM and crediting mechanisms generally. We situate these implications not only in the context of the CDM but also the Paris Agreement and draw general conclusions for the design of international crediting mechanisms under the Paris Agreement as well as crediting policies established at national level.

The CDM has provided many benefits. It has brought innovative technologies and financial transfers to developing countries, helped identify untapped mitigation opportunities, contributed to technology transfer and may have facilitated leapfrogging the establishment of extensive fossil energy infrastructures. The CDM has also helped to build capacity and to raise awareness on climate change. It also created knowledge, institutions, and infrastructure that can facilitate further action on climate change. Some projects have provided significant sustainable development co-benefits. Despite these benefits, after well over a decade of considerable experience, the enduring limitations of GHG crediting mechanisms are apparent.

- Firstly, and most notably, the elusiveness of additionality for all but a limited set of project types is very difficult, if not impossible, to address. Our analysis shows that many CDM project types are unlikely to be additional. Information asymmetry between project participants and regulators remains a considerable challenge. This challenge is difficult to address through improvements of rules. Further standardisation can be helpful for reducing transaction costs but has a limited scope, particularly within the CDM, for resolving additionality concerns. The scope for added standardisation is limited by the number of amenable project types and the wide variation of conditions across CDM host countries. Standardisation approaches have been most successful in regional crediting programs such as California or

Australia, where they have focused on a limited number of suitable and largely non-energy project types, such as landfills or coal mines.[98] The overall integrity of the CDM could only be improved significantly if the mechanism were limited to those project types that have a high likelihood of providing additional emission reductions. In our assessment, this would require excluding most of the current CDM project types and focusing mainly on projects that abate other GHGs than CO_2.

- Secondly, international crediting mechanisms involve an inherent and unsolvable dilemma: either they might create perverse incentives for policy makers in host countries not to implement policies or regulations to address GHG emissions – since this would reduce the potential for international crediting – or they credit activities that are not additional because they are implemented due to policies or regulations. This well-known dilemma has been discussed by the CDM EB without a resolution.

- Thirdly, for many project types, the uncertainty of emission reductions is considerable. Our analysis shows that risks for over-crediting or perverse incentives for project owners to inflate emission reductions have only partially been addressed. It is also highly uncertain how long projects will reduce emissions, as they might anyhow be implemented at a later stage without incentives from a crediting mechanism – an issue that is not addressed at all under current CDM rules.

- A further overarching shortcoming of crediting mechanisms is that they do not make all polluters pay but rather subsidize the reduction of emissions. This lowers the cost of the product or service, inducing rebound effects that are not considered under CDM rules and that lead to over-crediting. Most of these shortcomings are inherent to using crediting mechanisms, which questions the effectiveness of international crediting mechanisms as a key policy tool for climate mitigation.

It should be noted that the results of the analysis provided here for the CDM are to a large extent also relevant and valid for other international carbon offset or crediting programs, such as the Japanese Joint Crediting Mechanism (JCM), the Climate Action Reserve (CAR), the Verified Carbon Standard (VCS) or the Gold Standard (GS). The results are also relevant for the mechanisms to be implemented under Article 6 of the Paris Agreement, any mechanism to be used for compliance under the Carbon Offset and Reduction Scheme for International Aviation (CORSIA) and to a certain extent for the Joint implementation (for an overview see Kollmuss et al. 2015a). Even though the programs differ in many aspects, generally speaking, the CDM has been the origin and the role model for these offset programs. In particular, the CDM's approaches to additionality testing and baseline setting have served as the main blueprint for most other programs. With the aim of reducing transaction costs, rules and methodologies for additionality that have been borrowed from the CDM have been simplified, which did not generally strengthen their environmental integrity. Therefore, the issues raised here in the context of the CDM will remain relevant for other international offset programs.

The future role of crediting mechanisms should be revisited in the light of the Paris Agreement. The CDM in its current form will end with the conclusion of the second commitment period of the Kyoto Protocol. Several elements of the CDM could, nevertheless, be used when implementing the mechanism established under Article 6.4 of the Paris Agreement or when implementing (bilateral) crediting mechanisms under Article 6.2. However, the context for using crediting mechanisms has fundamentally changed. The most important change to the Kyoto architecture is that all countries have to submit NDCs that include mitigation pledges or actions. As of 15 December 2015, 187

[98] http://wupperinst.org/en/projects/details/wi/p/s/pd/377/.

countries, covering around 95% of global emissions in 2010 and 98% of global population, have submitted NDCs (CAT 2015). Many mitigation pledges in NDCs cover economy-wide emissions or large parts of the economy. This implies that much of the current CDM project portfolio will fall within the scope of NDCs.

The Paris Agreement requires countries to adjust their reported GHG emissions for international transfers of mitigation outcomes in order to avoid double counting of emission reductions. This implies that the baseline, and therefore additionality, may be determined in relation to the mitigation pledges rather than using a 'counterfactual' scenario as under the CDM, and that countries could only transfer emission reductions that were beyond that which they had pledged under their NDCs. Double counting can occur, inter alia, if the same emission reductions are accounted by both the host country – as reflected in its GHG inventory – and the country using these credits towards achieving its mitigation pledge. Avoiding such double counting could imply that host countries will have to add internationally transferred credits to their reported GHG emissions if the emission reductions fall within the scope of their mitigation pledges. This has several important implications.

Firstly, issuing and transferring credits that do not represent additional emission reductions or are under- or over-credited has other implications for global GHG emissions. Under the Kyoto Protocol, non-additional CDM projects or over-crediting increase global GHG emissions, whereas under-crediting from additional projects provides a net mitigation benefit. The implications are different and more complex when the emission reductions fall within the scope of the NDC of the host country: they depend on whether the credited activities are additional, whether they are over- or under-credited, the ambition of the mitigation pledge of the host country, i.e. whether or not it is below BAU emissions, and whether the emission reductions are reflected in the host country's GHG inventory[99] (Kollmuss et al. 2015b). Compared to the situation in which international transfers of credits would not be allowed, global GHG emissions could not be affected, decrease or increase due to the transfer of credits, depending on the circumstances. For example, if the host country has an ambitious NDC, non-additionality and over-crediting may not necessarily increase global GHG emissions because the country would have to reduce other GHG emissions to compensate for the adjustments to its reported GHG emissions. For the same reasons, under-crediting would not necessarily lead to a global net mitigation benefit. Additionality and over-crediting mainly matter when host countries have weak mitigation pledges above BAU emissions.

A second important implication relates to the incentives for host countries to ensure integrity and participate in international crediting mechanisms. If mitigation pledges are ambitious, host countries might be cautious to 'give away' non-additional credits. To achieve its mitigation pledge, the host country would need to compensate for exports of non-additional credits, by further reducing its emissions. Host countries with ambitious and economy-wide mitigation pledges would thus have incentives to ensure that international transfers of credits are limited to activities with a high likelihood of delivering additional emission reductions. However, our analysis showed that only a few project types in the current CDM project portfolio have a high likelihood of providing additional emission reductions, whereas the environmental integrity is questionable and uncertain for most project types. For those project types with a high likelihood of additionality, the potential for further emission reductions is limited and it is unclear whether host countries would be willing to engage in crediting for this 'low-hanging fruit' mitigation potential. The experience with Joint Implementation showed that most credits originated from countries with 'hot air', i.e. where the emission pledge is less ambitious than BAU emissions, while the potential for crediting was quite limited in countries

[99] Some emissions reductions may not be reflected in the country-wide GHG inventory, for example, because the country uses simple Tier 1 methods to estimate an emissions source which do not account for the emission reductions achieved through CDM projects or because the reductions occur in a sector that is not covered by the host country's GHG inventory.

with ambitious mitigation targets, also due to overlap with other climate policies (Kollmuss et al. 2015b). In conclusion, this suggests that the future supply of credits may mainly come either from emission sources not covered by mitigation pledges or from countries with weak mitigation pledges. In both cases, host countries would not have incentives to ensure integrity and credits lacking environmental integrity could increase global GHG emissions.

At the same time, demand for international credits is also uncertain. Only a few countries, including Japan, Norway and Switzerland, have indicated that they intend to use international credits to achieve their mitigation pledges. An important source of demand could come from the market-based approach pursued under the International Civil Aviation Organization (ICAO), and possibly from an approach pursued under the International Maritime Organization (IMO). For these demand sources, avoiding double counting with emission reductions under NDCs will be a challenge that is similar to that of avoiding double counting between countries.

A number of institutions are exploring the use of crediting mechanisms as a vehicle to disburse results-based climate finance without actually transferring any emission reduction units. This way of using crediting mechanisms could be more attractive to developing countries; they would not need to add exported credits to their reported GHG emissions, as long as the credits are not used by donors towards achieving mitigation pledges. The implications of non-additional credits are also different: they would not directly affect global GHG emissions, but could lead to a less effective use of climate finance, which could indirectly increase global GHG emissions compared to using the available resources more effectively. However, donors of climate finance aim to ensure that their funds be used for actions that would not go ahead without their support. They need to show that their investments *'make a difference'*. Given the considerable shortcomings with the approaches for assessing additionality, we recommend that donors should not rely on current CDM rules to assess the additionality of projects considered for funding.

Some countries pursue domestic crediting policies. South Korea allows companies to convert CERs from Korean projects into units eligible under its domestic emissions trading system. The Chinese and California-Quebec ETS allow the use of credits from domestic offsetting projects. Mexico, South Africa and Switzerland are pursuing polices that allow using domestic credits to meet tax or other obligations (see also the paragraph above on other offsetting programs). In these cases, using non-additional credits has no direct implication on global GHG emissions but will increase the country's costs towards achieving its NDC. In the long run, this provides incentives for these countries to limit crediting to project types with a high likelihood of additionality. However, meeting the ambitious long-term climate change mitigation goals of the UNFCCC and the Paris Agreement requires much stronger action and a rapid bridging of the emissions gap (UNEP 2015). It is hard to imagine that such ambitious goals could be achieved on a global level in a timely manner without a sharing of effort or burdens that could encompass some form of transfer of mitigation outcomes and/or results-based climate finance.

Taking into account this context and the findings of our analysis as well as other evaluations, we recommend that policy makers revisit the role of crediting in future climate policy:

- **Moving towards more effective climate policies:** We recommend focusing climate mitigation efforts on forms of carbon pricing that do not rely extensively on credits, and on measures such as results-based climate finance that do not necessarily serve to offset other emissions. If well designed, emission trading systems and carbon taxes have several advantages over crediting mechanisms: they do not require additionality to be assessed or hypothetical baselines to be set but rather rely on information on actual emissions for which information asymmetry is more manageable; in principle, they make the polluter pay rather than providing subsidies; and they expose all regulated entities to a carbon price, enabling up-scaled, sector-wide emission reductions. We recommend that international crediting mechanisms play a limited role after 2020 to address specific emission sources in countries that do not have the capacity to implement broader climate policies. Crediting should not be further pursued as a main tool for GHG mitigation.

- **Fundamental and far-ranging changes to the CDM:** To enhance the integrity of international crediting mechanisms such as the CDM and to make them more attractive to both buyers and host countries with ambitious NDCs, we recommend limiting the mechanism to project types that have a high likelihood of delivering additional emission reductions. We recommend reviewing methodologies systematically to address risks of over-crediting, as identified in this report. We further recommend revisiting the current approaches for additionality, with a view to abandoning subjective approaches and adopting more standardized approaches where possible. We also recommend curtailing the length of the crediting periods with no renewal. A larger question is whether the UNFCCC and CDM processes can create the consensus needed to make the fundamental changes needed to improve the integrity of the CDM in significant ways.
- **Purchase of CERs:** We recommend potential buyers of CERs to limit any purchase of CERs to either existing projects that are at risk of stopping GHG abatement ('vulnerable projects') or the few project types that have a high likelihood of ensuring environmental integrity. Continued purchase of CERs should be accompanied with a plan and support to host countries to transition to broader and more effective climate policies that ensure GHG abatement in the long-run. Purchase of CERs could also be used to deliver results-based finance in this context. Further, we recommend pursuing the purchase and cancellation of CERs, as a form of results-based climate finance, rather than using CERs for compliance towards meeting mitigation targets.
- **Mechanisms under Article 6 of the Paris Agreement:** Given the high integrity risks of crediting mechanisms, we recommend that Parties consider provisions that provide strong incentives to the Parties involved to ensure integrity of international transfers of mitigation outcomes. This includes robust accounting provisions, inter alia, to avoid double counting of emission reductions, but should also extend to other elements, such as comprehensive, transparent and ambitious mitigation pledges as a prerequisite to participating in international mechanisms.

In conclusion, we believe that the CDM had a very important role to play, in particular in countries that were not yet in a position to implement domestic climate policies. However, our assessment and other evaluations confirm the strong shortcomings inherent to crediting mechanisms. With the adoption of the Paris Agreement, implementing more effective climate policies including international cooperative actions becomes key to bringing down emissions quickly to a pathway consistent with well below 2°C. Our findings suggest that crediting approaches should play a time-limited and niche-specific role, where additionality can be relatively assured, and the mechanism can serve as stepping-stone to other, more effective policies to achieve cost-effective mitigation. In doing so, continued support to developing countries will be key. We recommend using new innovative sources of finance, such as revenues from auctioning of ETS allowances, rather than international crediting mechanisms, to support developing countries in implementing their NDCs.

8. Annex

8.1. Representative samples of CDM projects

8.1.1. Task

The population consists of 7,418 CDM projects which have 4 characteristics (location, technology, size, time), from which representative samples for three additionality approaches (investment analysis, barrier analysis and common practice analysis) should be drawn. One challenge consists of the fact that the additionality approaches are not directly known before the analysis. After some preliminary analyzes, we decided on a two-step approach.

1. Draw a representative sample with regard to all strata of the 4 characteristics of size 300. The additionality approaches are determined for the projects in this sample.
2. Draw sub-samples from the projects belonging to each of the three additionality approaches, which are representative for the strata of the 4 characteristics, as they occur for the projects of each additionality approach. The sub-samples shall consist of 50 projects each, which are to be further divided into one 30-project sample and two 10-project samples. The 30- and 10-project sample should each be representative of the strata and combine to the 50-project sample.

8.1.2. Approach

The challenge consists of the fact that the small sample sizes lead to less than one draw for many strata. In a first step, therefore, a randomised procedure is necessary to identify the strata from which to draw, such that the frequencies of the strata are best preserved from the population to the samples.

Drawing the 300-project sample

1. Randomly select strata from which to draw
   a) Calculate the target number of draws for each stratum as (stratum frequency) (population size) (sample size). These are decimal numbers and often below.

      In order to obtain an integer number of draws for a stratum, discretise its corresponding target number to the enclosing integers, e.g. 2.1 is randomly assigned either 2 or 3, where the probability of the assignment of the higher enclosing integer is weighted with (target number)^(lower enclosing integer). In the example, the probability that 2.1 becomes 3 is therefore weighted with 2.1 2 0.1. The number of target numbers assigned to the higher enclosing integer is determined such that the sum of all assigned lower enclosing integer and all assigned higher enclosing integer is as close as possible to the rounded sum of all respective target numbers.

      For example, assume 3 target numbers between 2 and 3, namely (2.1, 2.3, 2.9). Their rounded sum is 7. Drawing twice from two strata and three times from one strata yields the targeted 7 total draws. The third strata with the target number 2.9 has the highest chance of being chosen for the three draws.

   b) Strata with 0 frequency in the population have of course 0 frequency in the samples as well.
2. Randomly draw from the strata with the discretised target numbers of the previous steps.

Drawing sub-samples of the 300-project sample with the added additionality approach information

From the 300-project sample, we extract the projects that belong to each additionality approach, yielding three sub-samples. From each of these sub-samples, we draw samples of 50 projects, which are representative with regard to the strata of the 4 characteristics in the respective sub-sample. We employ the same approach as for drawing the 300-project sample (Section 2.1).

These three samples of 50 projects are ordered with respect to the strata of the 4 characteristics. Then we extract two sub-sets of 10 projects, one consisting of the 1st, 6th, 11th, 15th... project, the second consisting of the 3rd, 8th, 13th, 18th... project of the ordered sample. The 30-project sample consists of the remaining projects. This ensures that the strata within the 50-project sample are preserved in the smaller samples as well as possible.

8.1.3. Samples

Investment analysis:

69, 544, 1436, 1906, 2007, 2075, 2229, 2525, 3068, 3490, 3703, 4042, 4317, 4657, 5047, 5659, 5661, 5707, 5757, 6052, 6899, 7073, 7185, 7843, 7974, 8057, 8523, 8615, 8801, 9002

1875, 2315, 3033, 3186, 3799, 4600, 4687, 5843, 7024, 7551, 8903

1795, 2931, 4817, 5555, 6173, 6440, 7540, 8291, 8818, 8821

Barrier analysis:

244, 348, 582, 644, 1053, 1408, 1578, 1738, 2180, 2561, 3174, 3191, 3639, 3739, 3856, 4468, 4478, 4508, 4748, 5099, 5749, 5961, 6012, 6302, 6636, 7242, 7392, 7651, 8680, 9419

534, 831, 937, 1151, 1827, 2098, 4147, 5234, 7595, 8319

544, 2077, 2975, 3393, 4089, 5888, 6246, 7578, 8927, 9100

Common practice analysis:

69, 1227, 1602, 1737, 2007, 2075, 2098, 2109, 2302, 2315, 3068, 3186, 3642, 3670, 3799, 4687, 5006, 5359, 5659, 5843, 6173, 6553, 6899, 7648, 7936, 8125, 8140, 8506, 8636, 9699

588, 2486, 3994, 4317, 6440, 7400, 8093, 8505, 8523, 8879

366, 544, 1661, 1875, 3703, 4042, 4310, 5487, 7494, 8818

8.2. Information on suppressed demand in CDM methodologies

Table 8-1: Information on suppressed demand in CDM methodologies

Meth No.	Definition of baseline technology	Definition of MSL	Definition of baseline activity level
ACM0014	Methane Correction Factor of 0.4 for domestic wastewater	None	Project activity level (i.e. quantity of wastewater treated)
AMS I.A	Allows AMS I.L approach	Allows AMS I.L approach	Project activity level (i.e. quantity of electricity consumed)
AMS III.AR	Fossil fuel powered lamp	3.5 hrs per day x 2 CFL lamps (240 lux)	Deemed savings with fossil fuel lamp to match MSL, with annual growth in kerosene consumption
AMS II.G	Mix of fossil fuel cooking technologies	None	Project activity level (i.e. quantity of biomass saved)
AMS III.F	Unmanaged waste disposal with > 5m depth (methane Correction Factor of 0.8)	MSL is having a waste disposal site	Project activity level (i.e. quantity of waste converted to compost)
AMS I.E	Mix of fossil fuel cooking technologies	None	Project activity level (i.e. quantity of renewable energy used)
ACM0022	Unmanaged waste disposal with < 5m depth (methane correction factor of 0.4)	MSL is having a waste disposal site	Project activity level, although project proponent may propose another baseline
AMS I.L	Kerosene pressure lamp for lighting; car battery for appliances; diesel generator for larger loads	240 lux for lighting (50 kWh/yr using CFL), 195 kWh/yr for other appliances	Project activity level (i.e. quantity of electricity consumed) but with emissions factor of baseline technology
AMS III.BB	Kerosene pressure lamp for lighting; car battery for appliances; diesel generator for larger loads	240 lux for lighting (50 kWh/yr using CFL), 195 kWh/yr for other appliances	Project activity level (i.e. quantity of electricity consumed) but with emissions factor of baseline technology
AMS III.AV	Fossil fuel or non-renewable biomass to boil water (only requires justification if share of total population without access to improved drinking water is > 60%)	No minimum, but sets maximum level of 5.5 litres per person-day for crediting	Project activity level (i.e. quantity of water purified by project), but capped at 5.5 litres per person per day

Sources: Authors' own compilation

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