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September 18, 2020

Via Electronic Mail

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Re: Additional Information Regarding Carbon Offset Protocols for Greenhouse Gas Emission Reduction for Otay Ranch Resort Village (Village 13) (PDS2004-3810-04-002 (SPA), PDS2004-3810-04-003 (GPA), PDS2004-REZ-3600-04-009 (REZ), PDS2004-3100-5361-VTM, ENV. LOG NO. PDS2004-3910-04-19-005, SCH NO. 2004101058)

Dear Mr. Mattson:

This firm represents Endangered Habitats League ("EHL") in matters related to the Otay Ranch Resort Village (Village 13) project (the "Project"). We submit the following comments and the accompanying expert report on behalf of EHL concerning the above-referenced "Additional Information," including proposed revisions to Project mitigation measures M-GCC-7 and M-GCC-8 and the "Attachments" thereto. According to the County's "Notice of Additional Information," these revised mitigation measures will be included in the County's Final Environmental Impact Report ("EIR") for the Project prior to its consideration by the Board of Supervisors. EHL reserves the right to submit additional comments on the Project and Final EIR prior to or at the public hearing on the Project before the Board of Supervisors.

As revised, mitigation measures M-GCC-7 and M-GCC-8 fail to comply with applicable standards for mitigation under the California Environmental Quality Act ("CEQA"), Public Resources Code section 21000 et seq., and the CEQA Guidelines, title

14, California Code of Regulations, section 15000 et seq. In particular, the revised measures fail to incorporate standards adequate to ensure that carbon credits purchased from three identified registries will effectively and enforceably offset 100 percent of the greenhouse gas emissions that would result from construction and operation of the Project.

With minor exceptions—such as the preclusion of offsets from international projects—the proposed revisions substantively change very little about mitigation measures M-GCC-7 and M-GCC-8 as previously proposed. The County still proposes to rely on private carbon credit registries to evaluate, oversee, and enforce requirements of greenhouse gas protocols and methodologies adopted by those same registries. EHL's prior comments on various iterations of the EIR for this Project are still applicable to the revised mitigation measures, and are hereby incorporated by reference.

The accompanying report prepared by Barbara Haya, Ph.D., further demonstrates that the revised measures and supporting materials fail to ensure that credits purchased as mitigation for this project will represent real and additional greenhouse gas reductions, as they must in order to offset the Project's emissions. As Dr. Haya explains, protocols and methodologies employed by all three of the registries identified in the revised measures result in "over-crediting," largely based on the generation of credits from actions that would have happened anyway (i.e., non-additional credits). This "over-crediting" occurs under both approaches used by the registries to demonstrate additionality. Furthermore, although the revised measures purportedly disallow purchases of offsets generated under Clean Development Mechanism ("CDM") protocols and methodologies, several of the protocols and methodologies included in the attachments to the revised measures either explicitly rely on CDM methodologies or use a flawed CDM-type approach to determining additionality.

Dr. Haya further explains that over-crediting also occurs under particular protocols—including protocols governing forest offset projects—due to offset timing issues, leakage of demand for forest products, and flawed approaches to determining the baselines for crediting. Moreover, despite ample evidence in the existing literature that over-crediting is a serious problem, none of the three registries performs or requires an analysis of over-crediting risk sufficient to ensure offset quality. The County thus cannot conclude that credits purchased as mitigation are of sufficient quality to offset the Project's emissions based on the standards, protocols, and methodologies employed by the three identified registries.

As a result of these and other flaws, the revised measures fail to satisfy either the standards identified in the EIR or CEQA's requirements, including the requirements discussed in the Fourth District Court of Appeal's opinion setting aside a similar mitigation measure under the County's Climate Action Plan. *See Golden Door Properties, LLC v. County of San Diego* (2020) 50 Cal.App.5th 467. The revised measures thus cannot support a conclusion that the Project will ensure "no net increase" in emissions and thereby reduce the Project's global climate change impacts to a less-than-significant level. *See* Draft Final EIR at 2.10-24, 2.10-28, 2.10-37 to 2.10-38.

Very truly yours,

SHUTE, MIHALY & WEINBERGER LLP

Kevin P. Bundy

cc: Dan Silver, Endangered Habitats League

Encl.: Barbara Haya, Ph.D., Comments in Response to Additional Information Regarding Carbon Offset Protocols for Greenhouse Gas Emission Reduction

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Comments in Response to Additional Information Regarding Carbon Offset Protocols for Greenhouse Gas Emission Reduction

Otay Ranch Resort Village (Village 13) Project
San Diego County

Prepared by:
Barbara Haya, Ph.D.

September 17, 2020

Comments in Response to Additional Information Regarding Carbon Offset Protocols for Greenhouse Gas Emission Reduction

Otay Ranch Resort Village (Village 13) Project
San Diego County

These comments concern the offset protocols and credits that would be allowed under revised mitigation measures proposed to address greenhouse gas emissions caused by development of Otay Ranch Resort Village (Village 13). In preparing these comments, I have reviewed Mitigation Measures M-GCC-7 and M-GCC-8, Attachment A to M-GCC-7 (incorporating program manuals, standards, and protocols from three offset registries), and relevant literature. A copy of my CV is attached to these comments, along with copies of references cited herein.

San Diego County proposes to revise offset requirements in prior proposed mitigation measures to limit eligibility to a narrower set of offset credits. First, the revised measures restrict offset use to a specified subset of offset protocols under three offset registries: Climate Action Reserve (CAR), American Carbon Registry (ACR), and Verra (formerly VCS). The revised mitigation measures rely on the criteria and procedures that the registries use to develop offset protocols and vet whether offset projects meet protocol requirements. Second, the revised measures purportedly would disallow any credits generated under a Clean Development Mechanism offset protocol (also called a methodology), even if such credits are available from one of the allowed registries. Third, the revised measures impose geographical restrictions that would disallow international offsets and would instead limit offset use to credits generated in San Diego County if available, then California, and then the United States.

The criteria and procedures used by the registries to develop offset protocols in combination with the other restrictions proposed by the County are insufficient to ensure that the credits represent real and additional emissions reductions as required to meet the quality requirements laid out in the environmental impact report (EIR) for the Village 13 project. The registries do not use methods that ensure these quality requirements are met. The insufficiency of the County's proposal is demonstrated by published analysis documenting over-crediting by several protocols listed as acceptable in the EIR. While most of the allowed protocols have not been studied by independent researchers, some acceptable protocols permitted to be used by the County demonstrably fail to meet the quality standard defined in the EIR. As a result, the County has failed to demonstrate that its overall approach ensures that the credits meet basic quality requirements.

An important weakness in all of the registries is over-crediting based on the generation of credits from actions that would have happened regardless of the offset program. Additionality is inherent to the fundamental idea of carbon offsets and critical to their functioning. An offset program permits an emitter to emit more than an emissions cap or target in exchange for reducing emissions elsewhere. Accordingly, the offset program must *cause* emissions to be reduced. If the offset program generates credits from reductions that would have happened regardless of the offset program, and this causes the protocols to generate more credits than actual reductions in emissions, the emitter's emissions are not truly offset, and thus may exceed the cap or target.

Offset registries assess the additionality of offset projects in two ways. One is project-by-project additionality testing. For example, a number of VCS and ACR protocols listed as acceptable to San Diego County use this method (e.g. ACR Afforestation and Reforestation of Degraded Land protocol ver 1.2; Verra VM0013 Calculating Emission Reductions from Jet Engine Washing; Verra VM0014 Interception and Destruction of Fugitive Methane from Coal Bed Methane (CBM) Seeps). Under this approach, project developers can use specified tests (like a financial assessment or a barriers analysis) to demonstrate that the project would not have been implemented were it not for the offset income. The Clean Development Mechanism (CDM), the first major carbon offset program, is understood to have generated the majority of its credits from projects that are non-additional, largely because of the failure of the project-by-project additionality tests it uses, and specifically its financial and barriers tests, to effectively filter out non-additional projects (Cames et al. 2016; Haya 2010). An EU Commission commissioned study estimates that the additionality of 85% of CDM projects is questionable (Cames et al. 2016).

Here, the County's revised mitigation measures purportedly would not allow offset credits generated using Clean Development Mechanism protocols or methodologies. However, numerous protocols authorized for use under the revised measures explicitly reference and rely upon Clean Development Mechanism methodologies and tools, including the CDM's financial and barriers test and/or CDM-type project-based analyses for determining additionality. As a result, although the revised mitigation measures purportedly prohibit reliance on CDM protocols and methodologies, many of the protocols allowed for use under the revised measures suffer from exactly the same additionality problems as CDM protocols and methodologies and thus cannot be relied on to represent real, additional emissions reductions that can be used to offset on-site emissions.

The other approach to additionality, called a "standardized approach," defines additionality on the protocol scale. Under this approach, any project that meets the protocol eligibility criteria is allowed to participate and is considered additional. CAR uses this approach, as do some ACR and VCS protocols. The challenge with this approach is that if the registries develop a protocol that allows for the participation of offset project types that were already cost effective and being implemented to some extent without carbon offsets, then some non-additional projects would be allowed to participate and generate credits.

Many of the offset protocols listed as acceptable under the proposed mitigation measures, such as livestock digesters and nitrogen management, allow the participation of activities that were being implemented to some extent without offset credits. Accordingly, an analysis of rates of over- and under-crediting is needed to ensure that each protocol, in total, does not generate more credits than reductions achieved. How to do such an analysis, and the need for such an analysis to ensure offset quality, has been discussed and demonstrated in recent publications (Bento, Kanbur, and Leard 2016; Haya et al. 2020). However, none of the three registries identified in the revised mitigation measures requires such an analysis. Therefore the standards that the revised mitigation measures rely on do not adequately ensure either additionality or credit quality.

Furthermore, the revised mitigation measures do not ensure offset quality, as evidenced by their acceptance of protocols that have been documented as not being additional and real. Studies in the existing literature have examined California Air Resources Board (ARB) Forest protocol, which is based on CAR's Forest Protocol and shares many of the accounting methods and weaknesses with ARB's protocol. One study estimates that around 82% of credits generated by improved forest management projects under ARB's US Forest offset protocol do not represent real emissions reductions because of lenient methods for estimating leakage under the protocol (Haya 2019). Leakage happens when one landowner reduces timber harvesting only to have timber harvesting increase elsewhere to meet demand for timber. The study finds that the over-crediting occurs for two reasons: the disconnect in the timing of when credits are generated and leakage is deducted, and the choice of a low 20% leakage rate.

The CAR protocol has the same timing issue as the ARB protocol, which results in the bulk of the leakage-related over-crediting (Haya 2019).

While ARB uses a low leakage rate of 20% that leads to over-crediting, CAR uses a leakage rate of 20% to 80% depending on protocol version and rate of harvesting, resulting in over-crediting for some projects. Existing literature points to an actual leakage rate of over 80% (Barbara Haya and William Stewart 2019). Note that while the most recent version of the CAR protocol uses a 40% leakage rate as the default value, the author of the study on which CAR based its choice of a 40% leakage rate wrote a public comment to CAR arguing that the 40% rate was taken out of context; the figure was meant to be simply indicative that leakage is an issue and not to be applied in practice to a class of offset projects (Christopher S. Galik 2018). Like the ARB protocol, the CAR forest protocol results in an excess quantity of credits because of lenient methods for estimating the timing and quantity of leakage. This means that at least some of the credits issued under this protocol do not represent real, accurately estimated emissions reductions.

CAR's and ARB's US Forest offset protocols both also suffer from over-crediting due to the use of lenient baselines and additionality tests. Both protocols allow participating forestland owners to choose a baseline equal to the average carbon stocks in trees per acre in their region if a corresponding management regime is economically feasible and legally and contractually permitted. Many participating landowners choose baselines right at or a little above this common practice reference level. By definition, half of forest carbon in a given region is already on lands holding more than average carbon. There are also many reasons why some forestlands are managed to hold more carbon per acre than others, including multiple forest uses and forest management goals, types of timber produced, tree species, and topology. By definition, the ARB and CAR protocols allow a forestland owner managing their lands in a way that holds more than average timber to participate in the offset protocol and generate offset credits without changing their land management practice. This possibility was documented in one study of the ARB protocol which found that 38% of the forestland owners participating in the ARB protocol that responded to their survey said that they did not change their forest management practice to earn offset credits (Anderson and Perkins 2017). This means that 38% of landowners effectively admitted their projects were non-additional. CAR and ARB use the same fundamental method to assess project baselines.

VCS's forest protocols suffer from similar deficiencies. Two articles have criticized VCS' Darkwoods Improved Forest Management offset project in British Columbia, Canada, which uses VCS' VM0012 Improved Forest Management in Temperate and Boreal Forests (LtPF) protocol. The Office of the Auditor General of British Columbia finds that the baseline used by the project against which emissions reductions are estimated is too lenient (Office of the Auditor General of British Columbia 2013). The Auditor General also questions the additionality of the project by questioning whether the payments were necessary to the land purchase. Another paper also calls the baseline into question (van Kooten, Bogle, and de Vries 2014).

The very high rates of over-crediting documented by the offset programs and protocols that have been studied (including CDM methodologies and CAR's/ARB's and VCS' forest protocols), and the failure of the methods used by offset programs to ensure offset quality, means that offset credits cannot be assumed to be high quality based solely on their being listed by a certain registry. Offset programs today are more akin to supporting an incentive program, that is, providing a way to invest in a program that results in some uncertain and often over-credited quantity of emissions reductions, rather than generating quantified verified tons of emissions reductions (Haya et al. 2020). Therefore, offsets today truly do not "offset" a pattern of growth that fundamentally runs counter to sustainable city planning, climate change mitigation, and County climate action plans.

In sum, the revised mitigation measures for greenhouse gas emissions from the Village 13 project do not ensure offset quality and are insufficient to support a conclusion that all project emissions will be successfully offset.

/s/ Barbara Haya

Barbara Haya, Ph.D.
September 17, 2020

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Bento, Antonio, Ravi Kanbur, and Benjamin Leard. 2016. "On the Importance of Baseline Setting in Carbon Offsets Markets." Climatic Change 137(3): 625–37. http://dx.doi.org/10.1007/s10584-016-1685-2.

Cames, Martin et al. 2016. How Additional Is the Clean Development Mechanism? Berlin. https://ec.europa.eu/clima/sites/clima/files/ets/docs/clean_dev_mechanism_en.pdf.

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Haya, Barbara. 2010. "Carbon Offsetting: An Efficient Way to Reduce Emissions or to Avoid Reducing Emissions? An Investigation and Analysis of Offsetting Design and Practice in India and China." (Doctoral dissertation) Energy & Resources Group, University of California. https://escholarship.org/content/qt7jk7v95t/qt7jk7v95t.pdf.

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BARBARA HAYA, PhD

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Research Fellow, Center for Environmental Public Policy
Research Fellow, California Institute for Energy and Environment

EDUCATION

PhD, University of California, Berkeley, in Energy & Resources, 2010
Dissertation title: Carbon Offsetting: An Efficient Way to Reduce Emissions or to Avoid Reducing Emissions? An Investigation and Analysis of Offsetting Design and Practice in India and China
MS, University of California, Berkeley, in Energy & Resources, 2002
Thesis title: Evaluation of World Bank Public Participation Policies – Lessons for the Clean Development Mechanism
BA, Villanova University, major in Philosophy, concentration in Physics, 1991

RESEARCH & WORK EXPERIENCE

Center for Environmental Public Policy, Research Fellow, Goldman School of Public Policy, University of California, Berkeley (March 2018-present)
Leading the Berkeley Carbon Trading Project, a coordinated research and policy outreach program focused on the effectiveness of carbon offset programs.

California Institute for Energy and Environment, Research Fellow, University of California, Berkeley (Summer 2015-Present)
Working with the University of California to develop the system's strategy for procuring carbon offsets for use towards meeting the system's carbon neutrality goals.

Consultant on Climate and Renewable Energy Policy, Oakland, CA (January 2015-February 2018)
Consulted on carbon offsets and California climate policy for a range of organizations.

Stanford Law School, Research Fellow, Stanford, CA (Spring 2013-Spring 2015)
Led an interdisciplinary team of law and PhD students in a coordinated research and policy engagement program on California's expanding carbon offset program. Our goal was to support the development of an offsets program that effectively reduces emissions, and only credits emissions reductions that are real, additional, verifiable, and conservatively estimated. Our work focused on two new carbon offset protocols developed by California: Mine Methane Capture and Rice Cultivation.

Union of Concerned Scientists, Consultant, Berkeley, CA (Spring 2011-Spring 2013)
- Researched and advocated for procedures under California's global warming law for evaluating new and existing offsets protocols and overseeing the report verification process, to ensure carbon credits generated have a high likelihood of representing real and additional emissions reductions.
- Co-authored report analyzing the performance of California's publicly owned utilities towards meeting the state's 2010 Renewables Portfolio Standard

Lawrence Berkeley National Lab – China Energy Group, Graduate Student Researcher
Berkeley, CA (Spring 2010)
Analyzed the design of a sectoral crediting program that would support improved efficiency in the cement sector in Shandong province in China and credit emissions reductions from those support efforts.

International Rivers, Consultant, Berkeley, CA (2002-2009)

- Led the drafting of four position papers on the Clean Development Mechanism (CDM, the Kyoto Protocol's carbon offset program) by consensus among Climate Action Network (CAN) member organizations as coordinator of the CAN Flexible Mechanisms working group. CAN coordinates the efforts of 500+ NGOs at the international climate change negotiations.
- Submitted analysis and recommendations to the CDM Executive Board on the functioning of the CDM and CDM reform, proposed CDM baseline and monitoring methodologies, and hydropower projects applying for CDM registration.

PEER-REVIEWED PUBLICATIONS & WORKING PAPERS

Barbara Haya, Danny Cullenward, Aaron L. Strong, Emily Grubert, Robert Heilmayr, Deborah Sivas, Michael Wara (2020) Managing Uncertainty in Carbon Offsets: Insights from California's Standardized Approach. *Climate Policy,* DOI: 10.1080/14693062.2020.1781035

Barbara Haya (2019) Policy Brief: The California Air Resources Board's U.S. Forest offset protocol underestimates leakage. Goldman School of Public Policy Working Paper, University of California, Berkeley

Barbara Haya, Aaron Strong, Emily Grubert, Danny Cullenward (2016*)* Carbon Offsets in California: Science in the Policy Development Process. In *New Trends in Communicating Risk and Resiliency: A Multi-Disciplinary Approach to Global Environmental Change,* eds. J. Eichelberger, K. Taylor & Y. Kontar. Springer

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Barbara Haya, Malini Ranganathan, Sujit Kirpekar (2009) Barriers to sugar mill cogeneration in India: insights into the structure of post-2012 climate financing instruments. *Climate and Development* 1:66-81

Lara M. Kueppers, Paul Baer, John Harte, Barbara Haya, Laura E. Koteen, and Molly E. Smith (2003) A decision matrix approach to evaluating the impacts of land-use activities undertaken to mitigate climate change. *Climatic Change*, 63:247-257

Paul Baer, John Harte, Barbara Haya, Antonia V. Herzog, John Holdren, Nathan E. Hultman, Daniel M. Kammen, Richard B. Norgaard, Leigh Raymond (2000) Equity and Greenhouse Gas Responsibility. *Science*, 289:2287

OTHER PUBLICATIONS

Thomas Damassa, Taryn Fransen, Mengpin Ge, Krisztina Pjeczka, Barbara Haya and Katie Ross (2015) Interpreting INDCs: Assessing Transparency of Post-2020 Greenhouse Gas Emissions Targets for 8 Top-Emitting Economies. World Resources Institute, Washington, DC

Laura Wisland and Barbara Haya (2012) The Clean Energy Race: How Do California's Public Utilities Measure Up? Union of Concerned Scientists, Berkeley

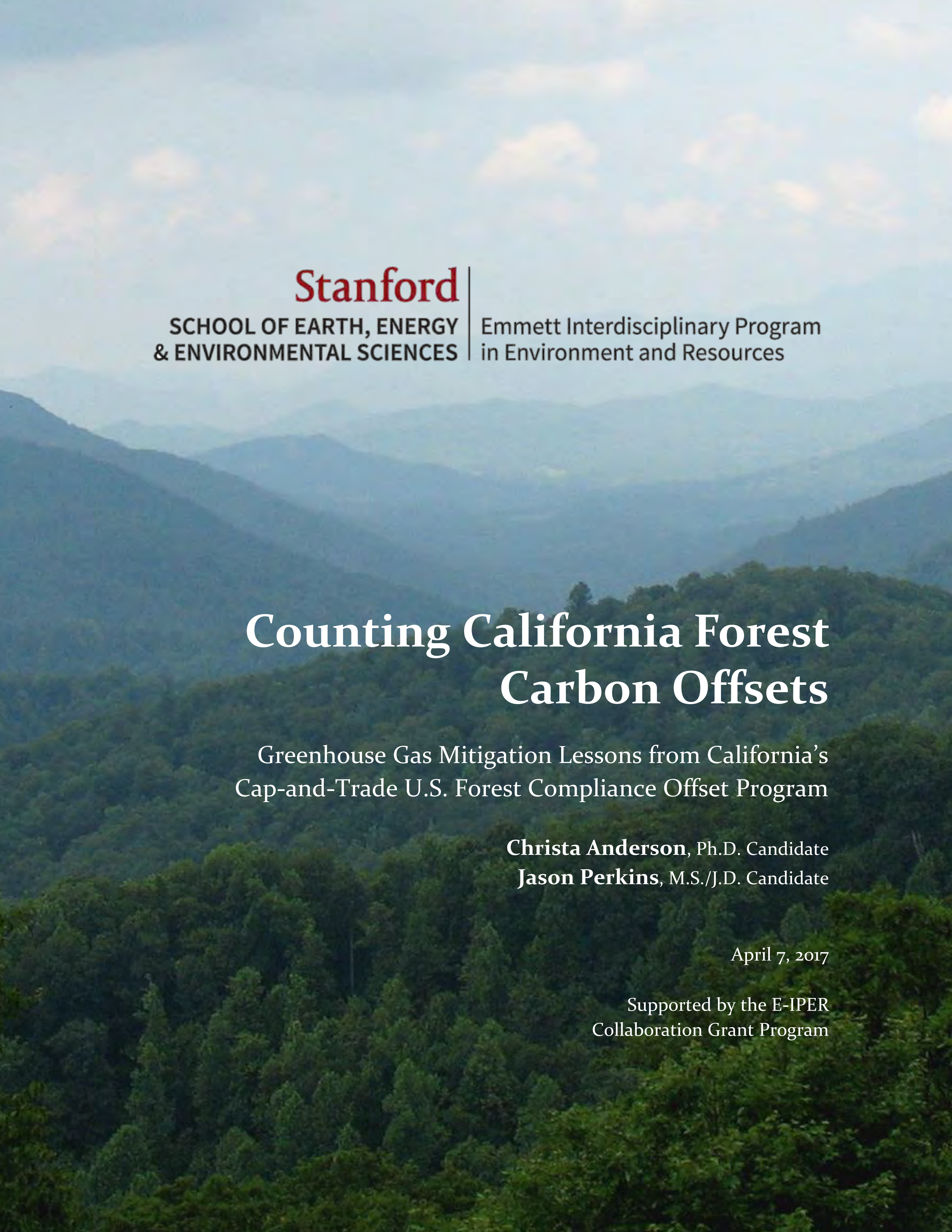
Alexander E. Farrell, Daniel Sperling, et al, (2007) A low carbon fuel standard for California, Part I: Technical Analysis & Part II: Policy Analysis. UC Berkeley Transportation Sustainability Research Center

Barbara Haya (2007) Failed Mechanism: How the CDM is subsidizing hydro developers and harming the Kyoto Protocol. International Rivers, Berkeley

PROFESSIONAL SERVICE

- Member of the Board of Directors, Carbon Market Watch, an NGO monitoring outcomes and development of carbon trading programs under UN agreements and around the world.
- Observer, seven Conferences of the Parties to the UN Framework Convention on Climate Change (the annual international climate change negotiations).
- Reviewed manuscripts for Climatic Change, Climate Policy, Energy Policy and Carbon Management.

Copies of References Cited
in Comments of
Barbara Haya, Ph.D (Sept. 17, 2020)



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Counting California Forest Carbon Offsets

Greenhouse Gas Mitigation Lessons from California's Cap-and-Trade U.S. Forest Compliance Offset Program

Christa Anderson, Ph.D. Candidate
Jason Perkins, M.S./J.D. Candidate

April 7, 2017

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Table of Contents

List of Figures

List of Tables

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Executive Summary

In 2013, California launched a multisector cap-and-trade market designed to reduce greenhouse gas pollution and meet the greenhouse gas mitigation targets set forth in Assembly Bill 32 (2006). Building on many years of effort and policy deliberation, California included in the cap-and-trade market the ability for covered entities with a compliance obligation to pay actors outside the program to reduce *their* emissions, frequently referred to as purchasing 'offsets'. Since 2013, California has operated a first-of-its-kind forest carbon offset program, in which 39 forest projects across the United States have earned credits through July 2016.

This research analyzes California's experience in running a first-ever compliance offset program for forests. To our knowledge, no official program evaluations of the forest offset program have been conducted to date. In the absence of identified and measurable official metrics and goals, this paper takes a more general 'lessons learned' approach, asking what the State has gotten from this policy innovation and what insights can be applied to other forest carbon sequestration efforts, like California's ongoing natural and working lands inventory.

From project design document review, survey responses and interviews with project owners and developers, we have four core findings. First, the California program has gone much further towards assuring additionality than other programs, including most voluntary forest offset programs, though some lingering and perhaps unavoidable questions remain. Second, a wide variety of California compliance entities buy forest offset credits, including some that operate facilities located in areas identified by the State as disadvantaged communities. Third, environmental benefits have been created by the program, though their financial importance may be minimal. Finally, California has taken forest offset protocols and policy to new levels, though the future of the market is quite uncertain given the need for supermajority reauthorization of the cap-and-trade program.

This paper first provides an overview of the forest offset program, its history and development, and some data about the current state of the program. It then describes the methods used in this study, and presents the above findings in detail. It concludes by illustrating several 'lessons learned' that should be incorporated by the Air Resources Board and cooperating agencies into the broader natural and working lands effort in California.

Overview and Development of the California Forest Carbon Offset Program

Before presenting the results of our research into the offset program, it is necessary to briefly describe the origins, history, policy design choices, and project performance of the California forest offset program in order to inform readers and put our findings in proper context. As of this writing, no comprehensive program evaluations have been conducted of the forest offset program.

Climate Change, Forests, and California Policy

Forest Carbon History and Potential

Forests have played an integral role in climate forcing emissions throughout American history, though only more recently have they served as a net carbon sink. Historically, American forests served as a significant net source of emissions in the 19th and early 20th Centuries, as old growth forests were harvested and trees were a primary building material and energy source. As fossil fuels replaced wood as a fuel source, and as forests regrew in the middle decades of the 20th Century, American forests became a net carbon sink, reaching their lowest net emissions rate (or, alternatively, highest carbon storage rate) in the 1980s. Since then, increased harvesting has lessened American forests' utility as a carbon sink, however significant carbon storage potential remains if deforestation is avoided in the 21st Century.[1] It has been estimated that forest carbon sequestration is equivalent to 12-19% of US fossil fuel emissions, [2] and the Obama Administration's Climate Action Plan noted the sequestration role being played by US forests,[3] though net carbon sinks from land use and forestry changes have been smaller in recent years than in 1990.[4]

California's Experience

Although the concept of forest offsets and other land use-related policies designed to incentivize carbon sequestration stretch back before the adoption of the

[1] Richard Birdsey et al., *Forest Carbon Management in the United States: 1600-2100*, 35 J. ENVIRON. QUAL. 1461, 1465 (July 2006).
[2] Michael Ryan et al., *A Synthesis of the Science on Forests and Carbon for U.S. Forests*, ISSUES IN ECOL. 13 (Spring 2010), at 1.
[3] Executive Office of the President, THE PRESIDENT'S CLIMATE ACTION PLAN (June 2013), at 11, available at https://goo.gl/KX1ULM.
[4] *See* U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2015* (February 2017) (Table 6-3 at 6-3, 6-4), available at https://goo.gl/GYpaXH.

Kyoto Protocol,[6] California's commitment to forest offsets can be traced to Senate Bill (SB) 1771 (Sher) in 2000.[7] That bill established the California Climate Action Registry (CCAR), a voluntary emissions inventory established by the state to define, measure and track greenhouse gas emissions. As part of its Climate Change Inventory, CCAR was instructed to acquire and develop data on the "costs, technical feasibility, and demonstrated effectiveness of . . . net reductions through the management of natural forest reservoirs."[8]

Land trust organizations sought to take this forest carbon data-gathering role at CCAR further, and promoted Senate Bill 812 in 2002 (Sher).[9] SB 812 directed CCAR to develop procedures and protocols for measuring and crediting the emissions impacts of "conservation and conservation-based management [activities in] . . . native forest reservoirs in California" that went beyond "applicable federal, state, and local land use laws and regulations."[10] How, exactly, CCAR would implement this measuring and crediting was a policy design task delegated to a state-convened working group that engaged land trusts, state foresters, forest industry representatives and an electric utility.[11]

This first 2002-2005 working group fleshed out many of the initial policy design questions, which led to the opening of California's voluntary carbon offset market in 2005. Importantly, from the very beginning, the state focused on a carbon-based payment structure, that is, strict accounting for forest carbon on a per-ton basis that could interface with cap-and-trade programs. The state chose not to take a practice-based or area-based payment approach to offset crediting that would have involved more general and less reliable carbon estimation and impact assumptions.[12] This tradeoff likely resulted in greater carbon sequestration from the projects who participated, perhaps multiple times more, but at the price of increasing project development and monitoring costs and thus a smaller population of potentially eligible projects. Indeed, this initial voluntary protocol (and its update in 2006) drew criticisms from other landowners not involved in conservation or conservation-based

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[6] Cornelis van Kooten et al., *How Costly Are Carbon Offsets? A Meta-Analysis of Carbon Forest Sinks*, 7 ENVION. SCI. & POL. 239, 239 (2004); Marissa Schmitz and Erin Kelly, *Ecosystem Service Commodification: Lessons from California*, 16 GLOB. ENVIRON. POLIT. 90, 90 (Nov. 2016). *See also* Mark Trexler et al., FORESTRY AS A RESPONSE TO GLOBAL WARMING (1989), available at http://goo.gl/Pwd8sg.
[7] 2000 Cal. Stat. 7482 et seq. (Ch. 1018).
[8] 2000 Cal. Stat. 7493 (Ch. 1018).
[9] Schmitz and Kelly, *supra* note 6 at 97.
[10] 2002 Cal. Stat. 2406 (Ch. 423).
[11] Schmitz and Kelly, *supra* note 6 at 97.
[12] *See* Ing-Marie Gren and Abenezer Aklilu, *Policy Design for Forest Carbon Sequestration: A Review of the Literature*, 70 FOREST POL. & ECON. 128, 130 (discussing studies of policies that took these approaches, at left).

management, as its stringent environmental and permanence requirements made initial participation rather unattractive for many for-profit private landowners and the California forest industry at the prices offered by voluntary carbon markets.[13]

A second working group, engaging more forest industry participants, followed after passage of California's landmark Assembly Bill (AB) 32 in 2006. From the beginning of planning the cap-and-trade portion of AB 32 compliance, the California Air Resources Board (ARB) signaled that forest offsets would play a cost-containment role in this new market. Cost-containment was an important concern – ARB's expectations for carbon prices in the cap-and-trade market ranged as high as $50/ton before the market began operating[14] (though in actual program experience, the allowance price has not risen above $20/ton since market launch[15]). Eventually, the State decided that entities could use offsets to meet up to 8% of their compliance burden, though use of offsets was optional and no particular participation goals were set.[16] With all reductions required to be "real, permanent, quantifiable, verifiable, enforceable, and additional" under AB 32,[17] the second protocol working group focused on "revis[ing] the early protocol to make it compliance-ready," a shift that had never before been attempted in any other jurisdiction.[18] In addition, to serve the goal of maximum participation and lower project costs (thus greater cost-containment for the cap-and-trade market), the new protocol was to be available for use nationwide, not just for projects in California.[19]

[13] Schmitz and Kelly, *supra* note 6 at 92, 97.
[14] Marc Lifisher, *California's First Auction of Greenhouse-Gas Credits Nears*, L.A. TIMES (November 6, 2012), available at https://goo.gl/hj2u2F
[15] Danny Cullenward and Andy Coghlan, *Structural Oversupply and Credibility in California's Carbon Market*, 29 ELECTR. J. 7, 9 (2016).
[16] *See* California Air Resources Board, Resolution 11-32 (October 2011), at 4, *available at* https://goo.gl/s3IbTZ; *see also* Press Release, CARB, California Air Resources Board Adopts Key Element of State Climate Plan (Release 11-44; October 20, 2011) *available at* https://goo.gl/Ieoq5M.
[17] CARB, California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation [hereinafter Protocol FAQ], at 1, available at https://goo.gl/DL8ZoV; 2006 Cal. Stat. 3427 (Ch. 488), now CAL. HEALTH AND SAFETY CODE § 38562(d) (2017). *See also* Timothy Fahey et al., *Forest Carbon Storage: Ecology, Management, and Policy*, 8 FRONT. ECOL. ENVIRON. 245, 249 (2010) (providing a more general elaboration on what these terms entail in the forestry context).
[18] Schmitz and Kelly, *supra* note 6 at 100, 101.
[19] Protocol FAQ, *supra* note 17 at 10.

Program History: The Design Challenges of Forest Offsets

Two Key Periods of Policy Design

Throughout this formative period from 2002-2009, when California went through two full rounds of forest offset protocol design, stakeholders grappled with five critical design challenges in creating standards for offset projects. First, three commodification hurdles stemming from the United Nations Framework Convention on Climate Change proceedings had to be navigated: additionality, permanence, and leakage.[20] In short, to deliver credible climate mitigation, carbon offset projects must only receive credit for emissions reductions that would not have otherwise happened without program intervention (i.e. be 'additional' versus a conservative, business-as-usual scenario), must show that the reductions they deliver will persist over time (be 'permanent') and must demonstrate that no other emission-causing land use changes will result (no 'leakage'). In addition, two other design challenges were present – how to maintain the environmental integrity of forests managed for carbon storage, and how to ensure market availability and acceptance of offsets as a salable commodity. Table 1 below summarizes how the 2002-05 and 2007-09 working group protocol-writing periods addressed these key design questions.[21]

[20] Steven Ruddell et al., *The Role for Sustainably Managed Forests in Climate Change Mitigation*, 105 J. OF FORESTRY 314, 316-17 (September 2007). The Kyoto Protocol's Clean Development Mechanism offset program uses similar, though not exactly the same, terms. *See* UN Framework Convention on Climate Change, GLOSSARY – CDM TERMS (Version 8.0) (defining "additional", "leakage", and "long term certified emissions reduction"), available at https://goo.gl/rZQCQ3.

[21] One update did occur between these dates in 2007, though most of the changes came with respect to more technical details of forest data and verification steps. *See* Climate Action Reserve, VERSION 2.1 at https://goo.gl/HpcpJJ (last visited March 15, 2017).

Table 1. Protocol Evolution on Key Design Questions, 2005 and 2009

Design Challenge	Description	Early Protocol Approach (Version 1.0, 2005)[22]	Compliance-Ready Protocol Approach (Version 3.0, 2009)[23]
Additionality	Proving emissions reductions as compared to a no-project counterfactual (a 'baseline')	• Crediting sequestration on project lands up to the maximum allowable harvest under CA forest rules	• Quantifying primary effect, consisting of: Crediting sequestration on project lands above a standardized Common Practice baseline, taking into account growth models, legal obligations and project start date
Permanence	Delivering a long-term guarantee of emissions reductions	• Requiring a perpetual conservation easement	• Requiring a 100-year commitment • Percentage contribution to buffer pool of credits depending on project-specific reversal risks • Allowed voluntary termination
Leakage	Preventing concomitant emissions from induced land use change and activities elsewhere	• Perform an assessment for activity-shifting leakage (required) and market leakage (optional)	• Quantifying secondary effects, including a project-specific leakage adjustment factor, but not including energy effects of alternate materials. • Market leakage adjustment only for IFM projects
Environmental Integrity	Guaranteeing sustainable and environmentally-conscious management (i.e. avoiding mere 'tree farm' projects)	• Requiring a perpetual conservation easement • Maintenance of native forests • Natural forest management (preventing even-aged cutting)	• Requiring adherence to sustainable harvesting practices (certification) • Natural forest management for the project area • Increasing standing live carbon stocks
Market Availability and Acceptance	Ensuring offset credit availability and purchaser confidence for a functioning offset market	• Five-year third-party certification of forest project results	• Lifting the conservation easement requirement • Permitting even-aged management (with limits) • Six-year third-party verification, with periodic desk reviews

As Table 1 details, the two California working groups engaged in an intricate policy design process in order to meet AB 32's requirement that offsets be real, permanent, quantifiable, verifiable, enforceable, and additional. Several tradeoffs were made in order to expand the possible pool of projects that could participate across the

[22] Climate Action Reserve, FOREST PROJECT PROTOCOL VERSION 1.0 (September 2005) at https://goo.gl/IoyTIs (last visited March 15, 2017) (see PDF of that name on this webpage).
[23] Climate Action Reserve, FOREST PROJECT PROTOCOL VERSION 3.0 (September 1, 2009) at https://goo.gl/5clWdB (last visited March 15, 2017) (same).

program. Changes were made to the additionality, permanence and environmental integrity requirements that facilitated greater program participation.

Analyzing California's Protocol Changes in the Second Working Group

For additionality, California first chose a performance benchmark test in 2005, allowing credit above harvest floors permitted by California regulations.[24] Once the program expanded to cover the continental US, however, a new approach was needed rather than one reliant on California regulations.[25] The second 2009 working group developed a multi-part approach to additionality that would be applicable across the country. Projects would only receive credit for:

1) actions taken after a defined project start date;
2) sequestration above all legal, regulatory and financial harvesting and stocking constraints; and,
3) credit relative to an area-specific 'Common Practice' baseline developed using US Forest Service Forest Inventory and Analysis Program Data ('FIA data').

This approach combines three types of additionality 'tests'—legal or regulatory, common practice, and timing tests, as identified in Trexler et al (2006). This generally represents a more stringent approach to additionality than in the earlier 2005 protocol. Having multiple additionality screens almost certainly increases the proportion of credited reductions in the program that are truly additional, but at a higher cost of participation and with less supply flexibility.[26]

Stakeholders also eased the permanence requirement to broaden participation. In order to incentivize lands managed for multiple uses (and not just conservation management), the 2009 protocol no longer required conservation easements. Instead, projects were required to give a 100-year sequestration commitment, and agree to set aside a project-specific proportion of their credits in a 'buffer pool' as insurance against later losses of carbon stock, referred to as 'reversals'.

This permanence policy change no doubt made the program more attractive to for-profit timber companies and family landowners, though it did not eliminate all potential reversal risks program-wide. Buffer pools, later described as the "most commonly used" approach to program impermanence risk, neatly manage the

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[24] *See* Mark Trexler et al., *A Statistically-Driven Approach to Offset-Based GHG Additionality Determinations: What Can We Learn?*, 6 SUSTAIN. DEVEL. L. & POL. 30, 31 (Winter 2006) (describing various illustrative types of additionality 'tests').
[25] In general, states must be careful about designing state programs that affect out of state entities, since regulations with 'extraterritorial' effect are vulnerable to legal attack under the Commerce Clause of the US Constitution or federal laws. *See generally North Dakota v. Heydinger*, 825 F. 3d 912 (8th Cir. 2016) (finding that a Minnesota clean energy law had impermissible out of state effect).
[26] *See* Trexler et al., *supra* note 24 at 38 (showing tradeoff between flexibility and additionality in Fig. 8).

individual risk of projects by essentially making them insure both themselves and others in the currency of the program – credits. However, this approach to risk does *not* take into account program-level reversal risks, i.e. the fact that individual project risks may under certain circumstances, be correlated.[27] The buffer approach essentially assumes that even if one project falls victim to a reversal event (e.g. a wildfire), most others will not. This program-level assumption may not hold if projects share certain common risk-relevant characteristics, like being located in close geographic proximity to one another. Cross-cutting risks, like the increased potential for wildfires as global temperatures rise and climate change progresses, can increase reversal risk across the board, not just for isolated individual projects.

Finally, with respect to environmental integrity, several changes helped make the program more attractive to timber companies and other landowners. Instead of a conservation easement, the 2009 protocol allowed a sustainable forestry certification to suffice as a commitment to environmental integrity. Though natural forest management remained a requirement, this definition was altered to allow some degree of even-aged management over portions of the project area, and in increments less than 40 acres. Projects were also expected to maintain or increase standing live carbon stocks,[28] as a way to promote biodiversity and wildlife habitat. In general, the 2009 protocol took several important steps to ensure greater participation while generally not changing the strict verification requirements that help facilitate investor confidence in offset credits.

Administration by ARB and Subsequent Challenges

The 2005 and 2009 protocols had been adopted pursuant to SB 1771 and SB 812, in stakeholder processes run through the CCAR, which was restructured and relaunched as the Climate Action Reserve (Reserve) in 2008. When ARB included forest offsets as part of the broader cap-and-trade program, however, the protocols then became official documents of the ARB, which noted that they had been drawn from version 3.2 of the Reserve's protocol.[29] After several years of accepting projects

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[27] David Cooley et al., *Managing Dependencies in Forest Offset Projects: Toward a More Complete Evaluation of Reversal Risk*, 17 MITIG. ADAPT. STRATEG. GLOB. CHANGE 17, 17 (2011) (describing three different kinds of correlated catastrophic reversal risks – fat tails, micro-correlations, and tail-dependence – that may be present, yet are unaccounted for by buffer pools). *See also* Christopher Galik and Robert Jackson, *Risks to Forest Carbon Offset Projects in a Changing Climate*, 257 FOREST ECOL. & MGMT. 2209, 2209 (describing systemic climate risks not accounted for in project-by-project analysis).
[28] *Compare* the 2005 protocol, *supra* note 19 at 15-16, *with* the 2009 protocol, *supra* note 20 at 12.
[29] *See* CARB Resolution 11-32, *supra* note 13 at 10. *See also* CARB, COMPLIANCE OFFSET PROTOCOL U.S. FOREST PROJECTS (ADOPTED: OCTOBER 20, 2011) [2011 Forest Offset Protocol], at 7 available at https://goo.gl/OpLQvv.

designated as Early Action, the compliance portion of the offset market launched in 2013 with the beginning of the cap-and-trade program.[30]

ARB implemented compliance protocols based on the 2009 protocol and updated the protocol in 2011, 2014, and 2015. Most of the key issues described above have not changed in these updates, including project-level risk assessments.[31] Some distinctions and developments have occurred across protocol updates, though there has been more consistency than change. [32] Since 2011, ARB has mandated higher levels of professional education and skills in verification teams.[33] Also, two updates to the protocol were released in 2014 and then in 2015, along with growing amounts of interpretive guidance and FAQs posted on the ARB website.[34]

Importantly, ARB's approach to additionality under this protocol and the other offset protocols was upheld as lawful by the California Court of Appeal in 2015 in *Our Children's Earth Foundation v. California Air Resources Board*.[35] That case decided that as a legal matter, ARB had the authority under AB 32 to implement the "standards-based approach" it has taken in adopting offset regulations and protocols since 2011, including for the US forest program.[36] CARB did not have to take an idiosyncratic project-specific approach to additionality, as the challengers had wanted. Observing that it is "virtually impossible to *know* what otherwise would have occurred in most cases," ARB could not be held to an additionality standard of omniscience and perfection – the legislature had directed ARB to "establish a workable method of

[30] CARB, OVERVIEW OF ARB EMISSIONS TRADING PROGRAM (updated February 9, 2015) at 2 https://goo.gl/qxOSqZ.

[31] *See also* CARB, COMPLIANCE OFFSET PROTOCOL U.S. FOREST PROJECTS (ADOPTED: JUNE 25, 2015) [2015 Forest Offset Protocol], at https://goo.gl/hJuX8c. See also CARB, COMPLIANCE OFFSET PROGRAM (updated March 8, 2017) (website with links to the protocols and other details from past iterations) available at http://goo.gl/WUBm4Y.

[32] For example, starting with the 2011 protocol, ARB has used the language of 'intentional' versus 'unintentional' reversals in dealing with project owner compensation liability, whereas the previous protocols had distinguished between avoidable and unavoidable reversals, though the substantive standards remain the same. *Compare* 2011 Forest Offset Protocol, supra note 25 at 59 with Climate Action Reserve, FOREST PROJECT PROTOCOL VERSION 3.2 (August 31, 2010) at http://goo.gl/XX3ubS (last visited March 15, 2017) at 63. *See also* CAL. CODE REGS. tit. 17 § 95802(a)(190) (2017) (defining intentional reversal), *available at* https://goo.gl/PUMgye.

[33] *See* Climate Action Reserve, COMPARISON OF RESERVE FOREST PROJECT PROTOCOL TO ARB COMPLIANCE OFFSET PROTOCOL FOR FOREST PROJECTS (last accessed March 15, 2017), *available at* https://goo.gl/jVrLLE (comparing Version 3.2 to the first CARB protocol).

[34] *See* CARB, COMPLIANCE OFFSET PROTOCOL U.S. FOREST OFFSET PROJECTS: ADOPTED JUNE 25, 2015 (updated December 2, 2015), *available at* https://goo.gl/7XiB8G (website explaining 2015 protocol).

[35] 184 Cal Rptr. 3d 365, 378 (2015). *See also* Alan Ramo, *The California Offset Game: Who Wins and Who Loses?*, 20 J. ENV. L. & POL. 109, 133-43 (Winter 2014), available at https://goo.gl/eCWrLQ (providing more background on the case).

[36] *Our Children's Earth Foundation*, 184 Cal Rptr.3d at 371, 373, 378.

ensuring additionality with respect to offset credits" in the context of "a market-based compliance mechanism," which is precisely what ARB did.[37]

Another important event came in 2014, when ARB recorded its first invalidation of offset credits under any protocol. The Clean Harbors Environmental Services waste incinerator in El Dorado, Arkansas participated in the Ozone Depleting Substances (ODS) protocol up until 2014, when a compliance issue with their hazardous waste environmental permit came to ARB's attention. For a period in 2012, it was found that Clean Harbors was not in compliance with their hazardous waste permit, though an investigation revealed no environmental integrity concerns with their ODS activities. After investigation, assessment, lobbying from market participants, and a final determination, ARB decided to invalidate 88,955 of the approximately 4.3 million tons of offset credits Clean Harbors had earned, sending ripples of concern through the offset marketplace.[38]

Though not the precise subject of legal action, or at least not yet, environmental justice concerns have been leveled at the offset program. Offsets are viewed skeptically by environmental justice advocates because they allow facilities located in disadvantaged communities to cover their emissions with offset reductions that happen elsewhere. This has been particularly concerning since several industry sectors have shown increased emissions since the 2013 start of the cap-and-trade market, though to date, the data made available to the public does not permit a very detailed assessment of these equity concerns. A 2016 analysis from scientists at UC Berkeley and several other California universities showed that most compliance entities did not use offsets, though those that did tended to have larger GHG emissions.[39] We discuss these environmental justice questions further in the Findings section.

[37] *Id*. at 379.
[38] *See* California Air Resources Board, Final Determination: Air Resources Board Compliance Offset Investigation Destruction of Ozone Depleting Substances (November 14, 2014), *available at* https://goo.gl/KGeHrr; Laurel Rosenhall, CalMatters, *A Little Town in Arkansas and its California Connection* 89.3 KPCC (July 26, 2015), *available at* https://goo.gl/bnwI11; Gloria Gonzalez, *Despite Market Outcry, California Voids Some Carbon Offsets*, ECOSYSTEM MARKETPLACE (November 14, 2014), *available at* https://goo.gl/Obv367.
[39] Lara Cushing et al., USC Dornsife Program for Environmental and Regional Equity, A PRELIMINARY ENVIRONMENTAL QUALITY ASSESSMENT OF CALIFORNIA'S CAP-AND-TRADE PROGRAM: RESEARCH BRIEF – SEPTEMBER 2016 [hereinafter Climate Equity Brief] at 7-10, *available at* http://goo.gl/2VrnXm.

Current Status of Today's Forest Offset Market

A Small But Notable Part of the Cap-and-Trade Market

According to the latest ARB Compliance Instrument Report at the time of this writing (up through Q4 2016), 95% of program compliance has been achieved through the use of allowances. Of the remaining 5% of offsets, a majority (3% of the total) comes from US Forest projects, with the remainder primarily coming from the Ozone Depleting Substances protocol and smaller amounts from livestock and mine methane capture projects. The amount of offset credits issued is slightly greater, as seen in Table 2. More credits have been issued than have been retired to-date, and Table 2 includes credits that are held back in the forest buffer pool and those that are held by offset project owners, market participants or compliance entities for future compliance. These figures are presented in Figure 2 and Table 2 below.

Table 2. ARB Offset Credits Issued as of March 11, 2017

Project Type	Ozone Depleting Substances	Livestock	U.S. Forest	Urban Forest	Mine Methane Capture	Rice Cultiv.	Totals
Compliance	7,222,320	1,521,590	21,851,822	- -	1,259,314	- -	31,855,046
Early Action	6,336,710	1,695,029	13,276,494	- -	2,879,684	- -	24,187,917
Totals	13,559,030	3,216,619	35,128,316	- -	4,138,998	- -	56,042,963

Source: ARB, Compliance Offset Program website,[40] at https://goo.gl/gBSWoj

[40] The text appearing alongside this table on the CARB website is: *Table includes all offset credits issued including offset credits placed in ARB's Forest Buffer Account, offset credits returned to an Early Action Offset Program's forest buffer pool, and offset credits subsequently invalidated.*

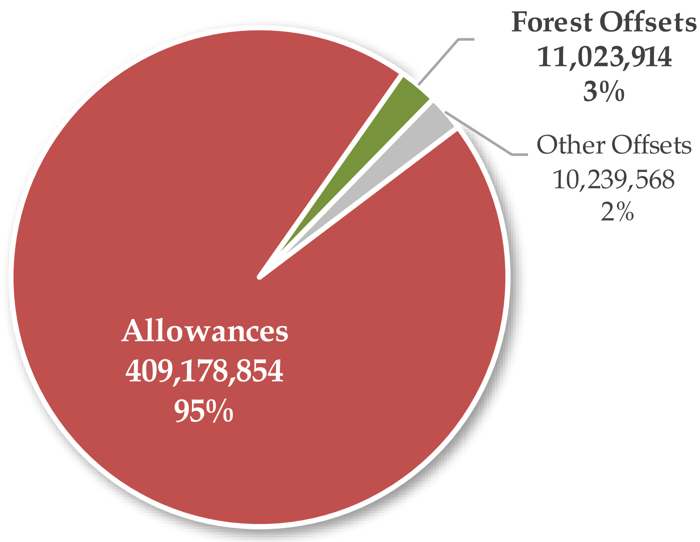

Figure 1. Retired Compliance Instruments Used 2013-16 in the California Cap-and-Trade Program. Source: ARB Compliance Instrument Report, Data through Q4 2016, accessed March 11, 2017, available at https://goo.gl/Jsj8kf

Given that offsets account only for 5% of the total compliance instruments used so far in the cap-and-trade program, it would be easy to dismiss their role in the sweep of California's aggressive climate policies. Indeed, one author likened the cap-and-trade market as a whole to 'dessert' after a full meal of other 'complimentary policies' for climate action including building energy efficiency standards, tailpipe emission standards, the Low Carbon Fuel Standard and renewable energy mandates. These policies are expected to account for approximately 70% of California's climate action, with cap-and-trade's 30% "no ton is left behind" contribution following at the end.[41] In this conception, offsets would be the garnish on that dessert – playing a small role in the last-in-line climate policy. Depending on the future carbon price, of course, offsets could stand to play a much larger role. If carbon prices increase considerably and more entities use closer to their full 8% allotment of offset-based compliance, then it is possible that offsets will exert considerable influence over the overall cap-and-trade program's economic and environmental outcomes.

Whether a large or small portion of compliance, offsets are somewhat financially beholden to the vagaries of the broader cap-and-trade market. Given that they are substitutes, offset prices according to market participants are generally pegged to the going rate for allowances, though at a small discount likely due to the additional search and transactions costs investing in offsets requires. With market data indicating

[41] Michael Wara, *California's Energy and Climate Policy: A Full Plate, But Perhaps Not a Model Policy*, 70 BULL. OF THE ATOM. SCI. 26, 27, 28 (2014).

a structural oversupply of compliance instruments in the cap-and-trade market,[42] the latest allowance price floor[43] of $13.57 may operate as somewhat of a price ceiling on offsets, especially when allowances are abundantly available for purchase from ARB or in the secondary market.

However, as a financial matter offsets should not so easily be dismissed. Both from published data made public by ARB,[44] and from anonymous survey results collected in this research, offset prices have been in the general vicinity of $9-13 per ton CO_2e. This price range combined with the information in Table 2 above suggests that the 56 million offsets issued to-date by ARB are in total worth around $500 million, with about $300 million of that in forest offsets alone. As a matter of state policy and as an unprecedented experiment in carbon sequestration program design, the forest offset program is certainly worthy of close examination.

Explaining the Distribution of Offset Credits by Project Type

As seen in Table 2 and Figure 2 above, the US Forest offset program accounts for a clear majority of both the credits earned and the offsets surrendered for compliance. This research also draws on project design documents available through the forest offset program, pulled from the climate registry websites as of July 2016. This analysis was conducted for all the projects that had then earned or were earning credits in the program.[45] Looking at just these projects that had made it all the way through the application process helps show how the project protocols are playing out in practice. From the project document data analyzed for this study, we draw the following project summary statistics in Tables 3 and 4, and the map in Figure 3 below.

Table 3. Credit-Earning Projects in the U.S. Forest Offset Program, July 2016

	Number of Projects	Total Credits	Total Acres
Improved Forest Management	33	24,142,947	854,598
Avoided Conversion	6	1,376,803	8,588
Reforestation	0	0	0
Totals	**39**	**25,519,750**	**863,186**

[42] Cullenward and Coghlan, *supra* note 15 at 13.
[43] CARB, FEBRUARY 2017 JOINT AUCTION #10: SUMMARY RESULTS REPORT (last accessed March 15, 2017), *available at* https://goo.gl/MSDdTD.
[44] *See* CARB, 2015 SUMMARY TABLE OF MARKET TRANSFERS (last accessed March 15, 2017), *available at* https://goo.gl/qwxFDS.
[45] Other analysis has focused on all projects listed in the program, an earlier step in the crediting process. *See* Erin Kelly and Marissa Schmitz, *Forest Offsets and the California Compliance Market: Bringing an Abstract Ecosystem Good to Market*, 75 GEOFORUM 99, 102 (2016).

Table 4. Credit-Earning Projects in the Offset Program by Protocol Type

	Compliance Program			*Early Action Program*		
	Number of Projects	**Total Credits**	**Total Acres**	**Number of Projects**	**Total Credits**	**Total Acres**
Improved Forest Management	16	16,757,595	691,393	17	7,385,352	163,204
Avoided Conversion	0	0	0	6	1,376,803	8,588
Reforestation	-	-	-	-	-	-
Totals	**16**	**16,757,595**	**691,393**	**23**	**8,762,155**	**171,792**

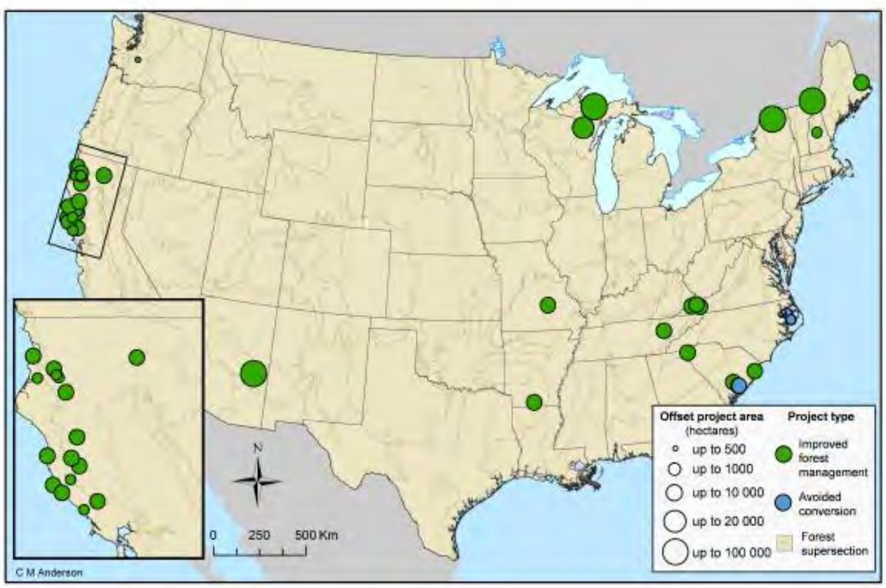

Figure 2. Map of Credit-Earning Projects in the U.S. Forest Offset Program, July 2016

Several trends stand out in the project data presented above. First, improved forest management (IFM) projects dominate the pool of projects that have made it to the crediting phase of the program. The potential reasons for this are several, though interviewees highlighted three important ones. Given that tree growth from plantings does not begin to show financially significant returns in terms of carbon accumulation for 15-20 years, the financial payback period for reforestation projects is simply too long, explaining why no projects have yet been credited. Second, only a handful of avoided conversion projects have been successfully credited in the program. This may be in part because in ARB's protocol, projects must show that the anticipated alternative land use for the project is more than 80% higher than its current forested value or face credit reductions.[46] This requirement essentially imposes a property conversion value test whereby converting to another land use must nearly double the value of the land, or face credit erosion by an 'uncertainty discount factor'. The purpose of this discount factor is additionality – only projects with high potential conversion values (i.e. those most likely to actually be converted) can make it into the program and receive full credit. Finally, IFM projects have the benefit of obtaining credit in the first year for the amount of carbon stock above their own modeled harvest baseline and above the Common Practice baseline. Put differently, this means that when an IFM project comes into the program, in the first year they are eligible for an initial crop of carbon offset credits for their current carbon stock that is above both the regional average stock (Common Practice baseline), and above the project-specific modeled baseline that includes financial, legal, and regulatory constraints. In short, above-average forests earn significant credits up front, and multiple interviewees acknowledged that this initial tranche of credits is all but essential for IFM project participation.[47] Many interviewees note that part of the initial revenue inflow is often used to finance startup costs.

Two additional pieces of evidence reinforce the essential role of up-front revenue. Published research on the potential financial returns from potential small offset projects in the northeastern US found that initial carbon stocking above the Common Practice baseline was the strongest predictive variable of financial returns.[48] Also, our analysis of project documents for the IFM projects currently earning credits indicates that 4 out of every 5 IFM projects in the program entered with carbon stocking above the Common Practice baseline. The quartile boxplot in Figure 4 below shows that most projects come in above, and many come in significantly above their area's Common Practice baseline. For a project at the median carbon stock (32 tons/acre above) and of a median size (9,753 acres for IFM projects), this means roughly 300,000 credits will be awarded up-front. At approximately $9 a credit, that amounts to $2.7 million in year 1 revenue for the project. Figure 5 below shows how IFM projects earn credit over time, demonstrating that about 70% of credits come in the first year and small annual amounts after, reflecting the (slow) net growth of carbon stock after year one.

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[46] 2015 Forest Offset Protocol, *supra* note 31 at 72.
[47] *See also* Kelly and Schmitz, *supra* note 45 at 105.
[48] Charles Kerchner and William Keeton, *California's Regulatory Forest Carbon Market: Viability for Northeast Landowners*, 50 FOREST POL. & ECON. 70, 75 (2015).

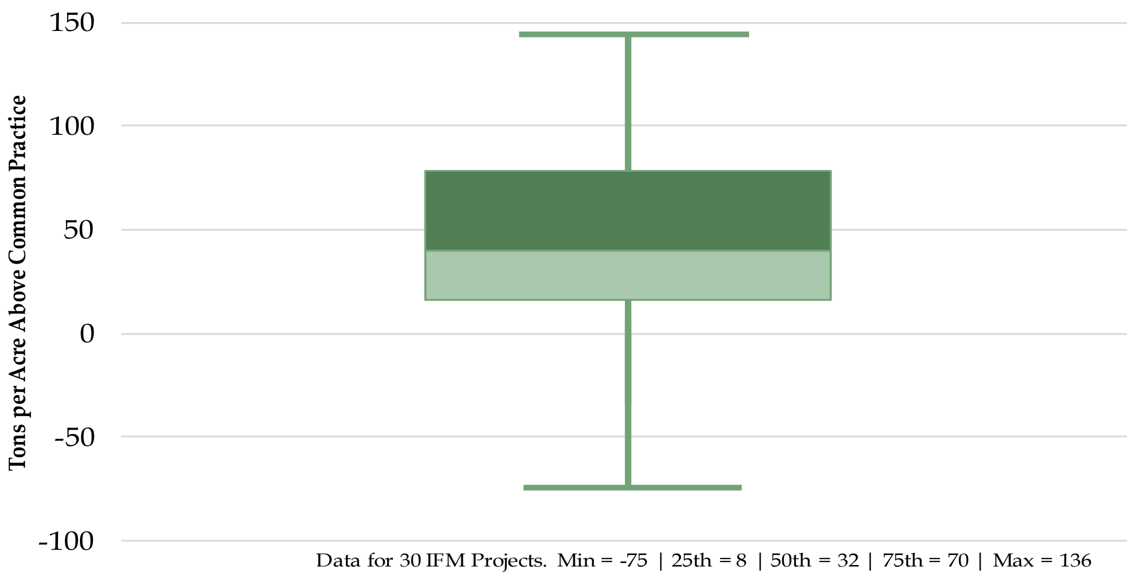

Figure 3. Boxplot of Initial Tons per Acre Above Common Practice from IFM Projects in the US Forest Offset Program as of July 2016.

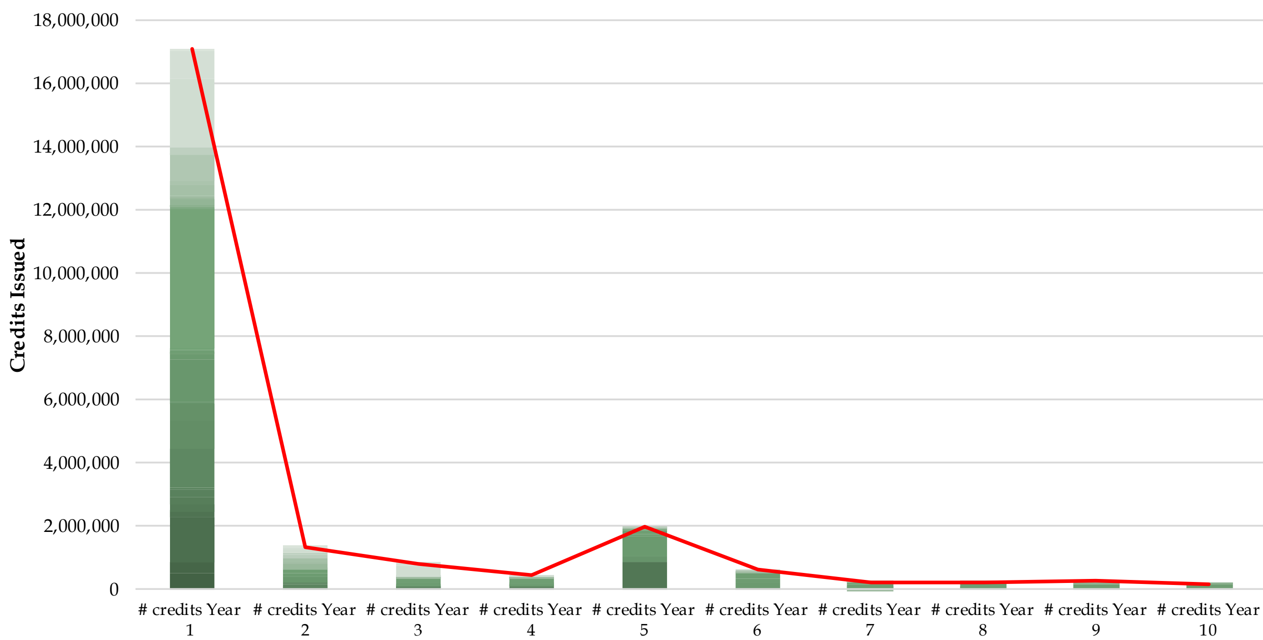

Figure 4. Total Credits per Year Earned by IFM Projects in the US Forest Offset Program as of July 2016.

Summary

In summary, today's California forest offset market is populated by several dozen projects selected for their exceedingly good fit under the rules of the program as specified in the ARB protocol. With a multifaceted approach to additionality, stringent verification and monitoring expectations and robust carbon accounting rules, the projects in the program reflect ARB's emphasis of quality over quantity in the number of projects that earn credits. Project developers have previously reported that only 5-10% of the projects they initially investigate end up being profitable enough to proceed given these high program hurdles.[49]

However, with over 100 projects listed in the program so far (an initial stage in the application process), it is possible that significantly more projects could complete the process and begin earning credits if the price of carbon increases. Reauthorization of the cap-and-trade program past 2020 could cause such a price spike, which would likely lead to the crediting of many more IFM and avoided conversion projects. These projects would presumably be less financially dependent on returns from crediting their initial stocking over the Common Practice baseline, as future growth would be more remunerative. It remains to be seen whether any plausible market scenario will bring reforestation projects into the program, though. What is clear is that future market dynamics will depend largely on future developments in state policy and carbon prices.

[49] Kelly and Schmitz, *supra* note 45 at 104.

Methods

This review undertook three approaches to assessing forest offset project and program characteristics. First, we conducted an assessment of all 39 credited forest offset projects (listed in Appendix I) using a text review of the public project documents available for each project. Projects must meet stringent reporting requirements, and must be listed on approved carbon registries with public project documents. For this research, available documents included an offset verification statement, annual offset project data reports, offset project listings, and biennial project emissions reporting, yielding a database of 46 variables for each project.

Second, we administered a survey of forest owners/operators and a separate survey of forest offset project developers to gain information beyond what is reported in project documents. The surveys included questions about participant motivations, forest offset credit sales, and other project characteristics, experiences, and opinions. Online surveys were sent to all 32 identified project owners/operators. Postcard reminders were mailed, seven survey reminders were sent by email, and hard copy surveys were sent to those who did not respond within a week. 17 complete survey responses were collected, with a survey response rate of 53%.[50] These responses covered 21 of the 39 credited projects, also 53% of the total. The same process was used for the project developer survey. Three of four project developers responded. For context, we estimate that 72% of all projects in the program used a project developer to implement their forest offset project.

Third, we conducted in depth interviews with eight project owners (including four on-site forest visits) and with two project developers. These in depth interviews provided nuanced details for specific projects and corroborated information gained from the document review and survey. Between surveys and interviews, this research obtained detailed data from the owners of 28 of the 39 projects credited in the program (72%). This paper draws on each of these three data sources—documents, survey responses, and interviews—in formulating the following findings and lessons.

Last, we compiled additional data for mapping forest offset use in disadvantaged communities (see Finding 2 below). Using a combination of publicly available data from ARB and other sources, we analyzed the share of forest offsets that were used at facilities in disadvantaged communities (estimated to be a pro-rata share of their parent entity's offset use) as compared to offset-linked facilities not located in disadvantaged communities. This analysis used forest offset data from 2013-2015, and annual emissions from facilities in 2014, as described further in footnote 60 below.

[50] The majority of projects covered in survey responses were Early Action projects.

Findings

Based on document analysis, interviews, and surveys, we elaborate four primary findings on California's forest offset program below.

Finding #1: Additionality is Much Stronger than in Other Forest Offset Programs, But Questions Remain

Project 'additionality' refers to the idea that a forest offset project earns credits for changing practices from what would have happened without the project. For example, forest owners can earn credits by cutting less timber than they would have otherwise, or by keeping forest land standing that they would have otherwise converted to agriculture. The challenge with credit accounting under this approach is that it is never possible to know the counterfactual (what would have happened in the absence of the forest offset project) for certain. By definition, all counterfactuals are hypothetical exercises. Many forest offset programs have been plagued by difficulty in determining the appropriate counterfactual or 'baseline' activity level. California's program continues to face this challenge as well, but it has gone several steps further than prior efforts on forest offsets.

Efforts to Ensure Additionality

This analysis finds that California's forest offset program has incorporated several accounting and protocol elements in an effort to ensure project additionality. First, projects entail rigorous carbon accounting with standardized baselines across the country which are established with long-term forest data from the US Forest Service Forest Inventory and Analysis program.[52]

Second, forests are required to provide data showing that the project-specific harvest baseline against which their project will be credited would have been financially viable.[53] That is, when forests set counterfactual timber harvest levels or forest conversion rates, they are required to provide a net present value analysis or recent sales records from neighboring forests showing that the proposed baseline timber harvest is financially viable for the duration of the offset project.

Third, projects are required to exclude any forest carbon that is already legally protected by another mechanism.[54] Forest carbon that is already legally protected from harvest would by definition not be harvested, and any crediting for such carbon would

[52] 2015 Forest Offset Protocol, Appendix F, *supra* note 31 at 139.
[53] 2015 Forest Offset Protocol, *supra* note 31 at 28, 62.
[54] 2015 Forest Offset Protocol, *supra* note 31 at 27.

clearly not be additional. Common legally protected forest carbon in offset projects, for which projects do not receive credits, include legal prohibitions from harvest near streams, on steep slopes, or near endangered species. Another common legal prohibition that prevents some forests from participating in the offset program is the presence of a longstanding conservation easement that prohibits timber harvest on the forest land in question.[55] The rigor of these requirements is new to the California offset program; preceding voluntary forest offset programs have not generally required this level of scrupulousness.

The Views of Forest Owners and Operators on Additionality

Our survey asked forest owners and project developers to assess their confidence in the additionality of both their forest offset project and other projects. Not surprisingly, the majority of respondents were confident that both their project and other projects in the program are additional (Figure 5).

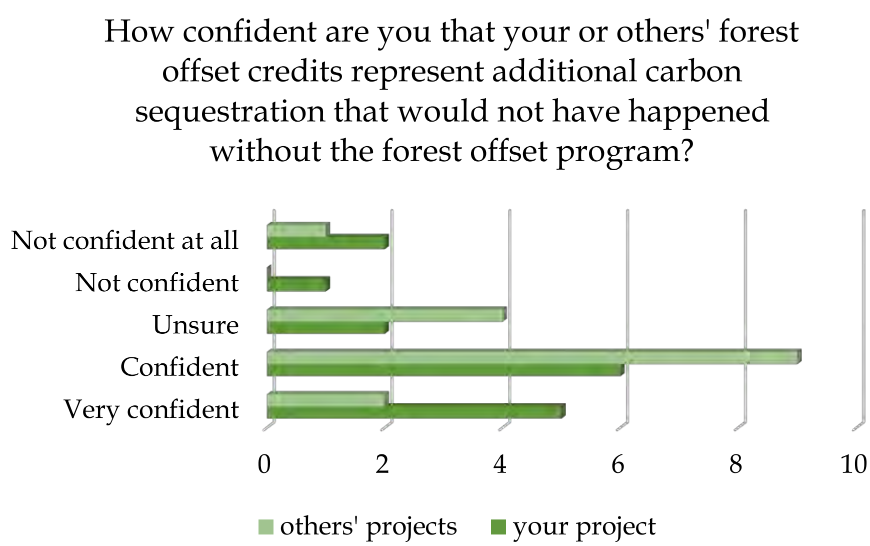

Figure 5. Survey responses from 17 forest owners re: confidence in additionality.

In more detailed narrative survey responses there were two types of information that stood out on additionality. First, some project owners and operators shared that as long as they maintained property ownership, they were unlikely to have harvested timber at the baseline level calculated in project documents. This would be a concern for project additionality. Second, in both interview and survey responses, project owners and operators emphasized that the *commitment* to carbon sequestration was

[55] For early action projects which started prior to the compliance market start, projects that already had conservation easements were grandfathered in to the program.

additional. In other words, projects were thought to be additional regardless of the counterfactual because they ensured a 100-year commitment to maintaining forest carbon. The counterfactual would be no *commitment* to maintaining carbon and thus an uncertain future for the forest carbon in question.

Our survey also asked forest owners and operators whether participation in the forest offset program changed their forest management practices. A change in forest management practices would signify a change from the baseline activity and would serve as another indicator for project additionality. Of survey respondents, 4 reported that starting a forest offset project changed their forest managed practices, an additional 6 reported that practices changed somewhat, and 6 reported that practices did not change (Figure 6). Management changes reported by project operators included decreasing harvest levels, adding a forest certification, and purchasing additional forest land.

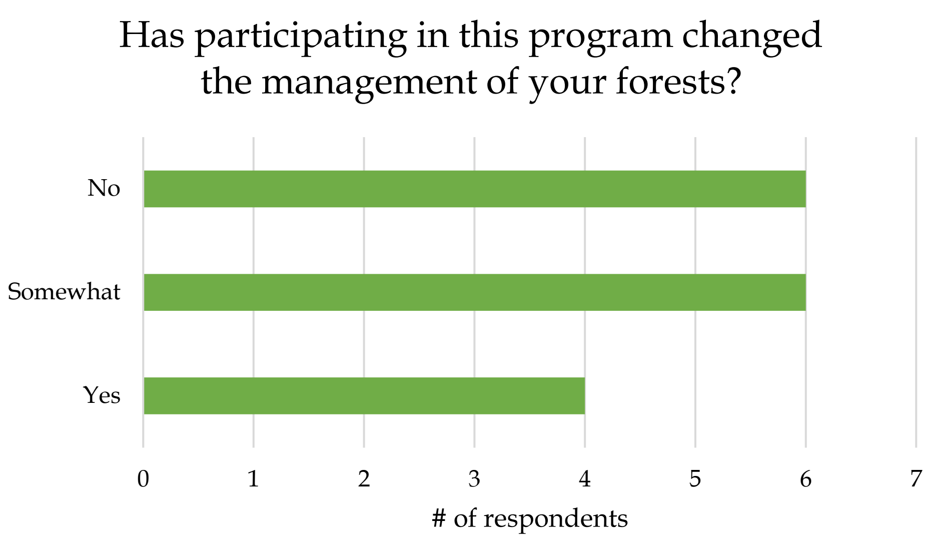

Figure 6. Survey responses from 16 forest owners re: forest management.

Concerns about Project Additionality

One of the most commonly voiced concerns about additionality in the forest offset program concerns conservation easements. California's forest offset protocol allows projects to simultaneously implement a conservation easement together with a forest offset program, and this is a common occurrence in the program. This type of joint implementation of an easement and offsets would be considered additional under a 'barriers test' of additionality, which assumes that a project would not be possible (i.e. would face insurmountable barriers) without implementing both the offset project and the easement jointly.[56] However, in the initial Early Action period of the forest offset program, projects were able to join the program even if they had long standing conservation easements already in place. Any easement stipulations prohibiting timber harvest still had to be excluded from crediting, but this early period included multiple projects with long-standing conservation easements already in place. It is an important positive amendment that such projects are no longer permitted to join the offset program.

Finding #2: A Wide Variety of Entities Purchase Offset Credits

Forest Offset Credit Buyers

In the California cap-and-trade market as of 2015, 272 entities and 438 facilities fall under the cap. (Each 'entity' may have multiple facility sites.) According to data from CARB[57] analyzed in this study, 150 facilities purchased offsets and 79 have used forest offsets from 2013 through 2015. The cap-and-trade policy limits each entity to covering a maximum of 8% of its obligations by using offsets. As discussed earlier, the total rate of use falls well below the 8% maximum at present.

Among forest project owners surveyed, 53% of project owners sell their forest offsets directly to entities with a California offset obligation. The remainder of owners sell their credits to brokers and intermediaries who in turn sell credits to entities in the cap-and-trade program. Offsets were initially included in California's cap-and-trade program to serve as a cost containment mechanism. Capped facilities could avoid or delay the most expensive emissions reductions investments by purchasing offsets. However, since the carbon price in the California market has remained very low through the duration of the market to date,[58] offsets have not served as a cost containment mechanism, and the cost of offset credits has also remained low. 11 survey respondents anonymously reported on their average carbon sales price. The average price from this data is $10.20/ton, with a range of $9-$13/ton. As shown below in Figures 13 and 14, most respondents anticipated that prices would increase slightly or stay about the same up to 2020. Estimations were similar for prices after 2020, with the addition of a few respondents anticipating prices to increase significantly (more than a 25% increase).

[56] *See* Trexler et al., supra note 24 at 31.
[57] See explanation in footnote 60 below.
[58] Cullenward and Coghlan, *supra* note 42 at 13.

Forest Offset Credits and Environmental Justice

The environmental justice community in California has voiced concern that use of offsets disproportionately impacts disadvantaged communities in the state. Environmental justice advocates have argued that facilities that buy offsets are likely located in disadvantaged communities, and if emissions were reduced onsite instead of through offsets, those communities would gain health benefits from reduced pollution, especially of non-GHG co-pollutants such as particulate matter and air toxics.[59] We used offsets sales data and facility emissions data from CARB to construct a first-order approximation of the connection between offsets and emissions in disadvantaged communities and to assess whether forest offsets have been used disproportionately in disadvantaged communities.[60]

Forest offsets account for a small share of facility emissions across all facilities. 79 of 438 facilities in the cap-and-trade program (total as of 2015) used forest offsets. Of these facilities, 43% (34) are located in disadvantaged communities (see Figure 7). In 2014, facilities in disadvantaged communities on average offset 2.2% of their emissions with forest offsets, whereas facilities not in disadvantaged communities used offsets slightly more, covering 3.2% of their emissions. As with the rate of use, the total *number* of estimated forest offsets used is also higher outside of disadvantaged communities. Where facilities in disadvantaged communities used close to 70,000 forest offset credits on average, facilities outside of disadvantaged communities used

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[59] *See* Climate Equity Brief, *supra* note 39 at 7-10.

[60] This analysis weaves together the forest offsets information reported in the CARB Compliance Reports (available for 2013-14 and 2015) and compares it to facility information made available in CARB's the Integrated Emissions Visualization Tool, with an overlay of the OEHHA's CalEnviroScreen 3.0 shapefile for disadvantaged community location (defined here as a score of 75 or above). We first downloaded all data for the facilities listed as subject to cap-and-trade as of 2013 in the Integrated Emissions Visualization Tool (324 facilities). Then we matched that facility information with the forest offset usage data reported in the Compliance Report's Compliance Offsets Detail tab by entity ID. This matching used the Entity ID data, and ARB GHG ID info reported in the Compliance Summary tab of the Compliance Reports to link entities, and the facilities they own, with offsets usage. Unfortunately, because CARB does not report offset usage down to the facility level, our analysis at that point had to use a pro-rata estimate for each entity; that is, if a particular entity had purchased and retired 100,000 offsets, and owned four facilities subject to cap-and-trade, we have assumed that they retired 25,000 offsets for compliance at each facility. More detailed information would need to be made public about both offset purchase and retirement as well as about facility location and emissions in order for finer and more instructive sets of analyses to be conducted. We recommend that CARB at a minimum commission a program evaluation of the environmental and equity impacts of the offsets program using more finely grained data than what has been made publicly available. For data sources, please visit CARB, INTEGRATED EMISSIONS VISUALIZATION TOOL (last accessed March 15, 2017), available at http://goo.gl/WJGiVF; CARB, CAP-AND-TRADE PROGRAM (last accessed March 15, 2017), available at http://goo.gl/4qeAfj (specifically, under Publicly Available Market Information, the 2013-14 and 2015 Compliance Reports); Office of Environmental Health Hazard Assessment, CALENVIROSCREEN 3.0 (last accessed March 15, 2017), available at http://goo.glK9Foqg (specifically the CalEnviroScreen 3.0 Results Shapefile).

more than 130,000 forest offset credits on average. Initial analysis suggests that trends are similar when all offsets, not just forest offsets, are considered. Facilities in disadvantaged communities used 6.4 million offsets cumulatively, while facilities outside of disadvantaged communities used 10.2 million offsets cumulatively. Further analysis and more finely-grained data are needed to more precisely compare the effects of offsets on emissions in and out of disadvantaged communities.

Though any lessening of the incentive to reduce pollution in disadvantaged communities is concerning, and though offset data alone cannot tell us precisely what would have happened in the absence of offset availability, it appears that the use of offsets to date affects but does not appear to disproportionately impact disadvantaged communities. As compared to other areas, fewer facilities in disadvantaged communities purchase offsets, and those that do use a smaller share of offsets. But, this trend could change over time and should continue to be monitored.

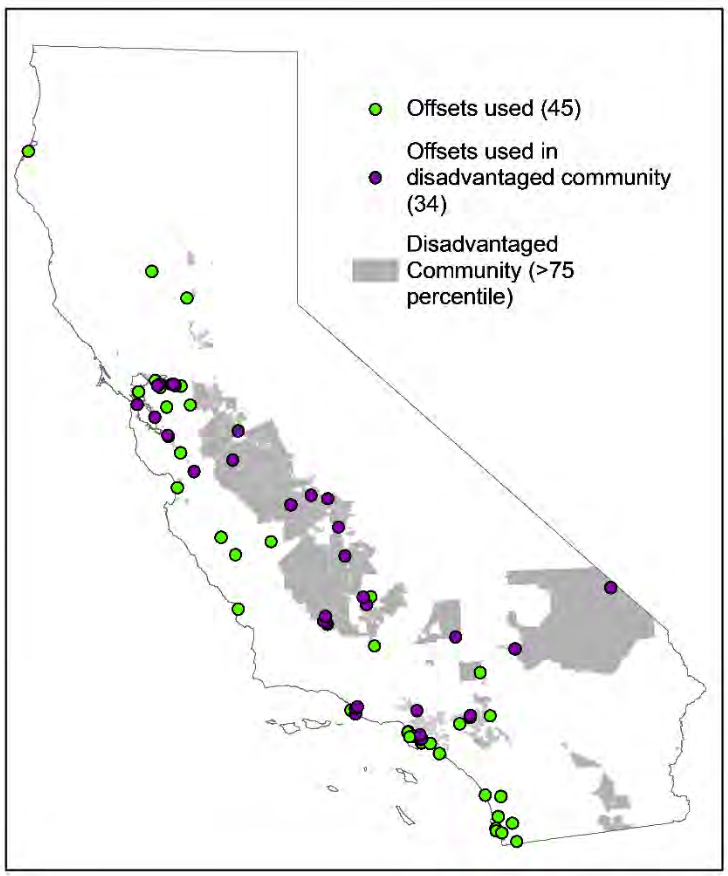

Figure 7. Location of Cap-and-Trade Facilities whose Parent Entities Retired Offsets to Meet Compliance Obligations.

Finding #3: Project Co-Benefits Are Not Monetized

Project document review, interviews, and surveys all corroborate that forest offset projects convey co-benefits for conservation and sustainable forest management. However, delivery of these project co-benefits is a decidedly secondary concern to the financial success of projects, which is conveyed by carbon credits. Project co-benefits may be of greater interest in the long run, and several projects report potential for 'benefit stacking,' or deriving financial benefit from co-benefits alongside carbon revenues from participating forest land.

From our analysis of project design documents, 92% of credited offset projects report having at least one environmental co-benefit. In the survey data, however, most respondents report that co-benefits are not important in the sale of their offset credits (11 of 16, 69%). This indicates that while forest owners are aware of the existence of co-benefits, these co-benefits are not financially relevant to the sale of offset credits, though they may be relevant to other ecosystem services markets. Similarly, interviewees often noted their co-benefits with interest, and enjoyed telling stories about them, but generally acknowledged that carbon credit buyers do not ascribe monetary value to co-benefits.

Survey respondents report that their projects provide a number of co-benefits. Most respondents also report that co-benefits are present, but few expend resources to measure these benefits.

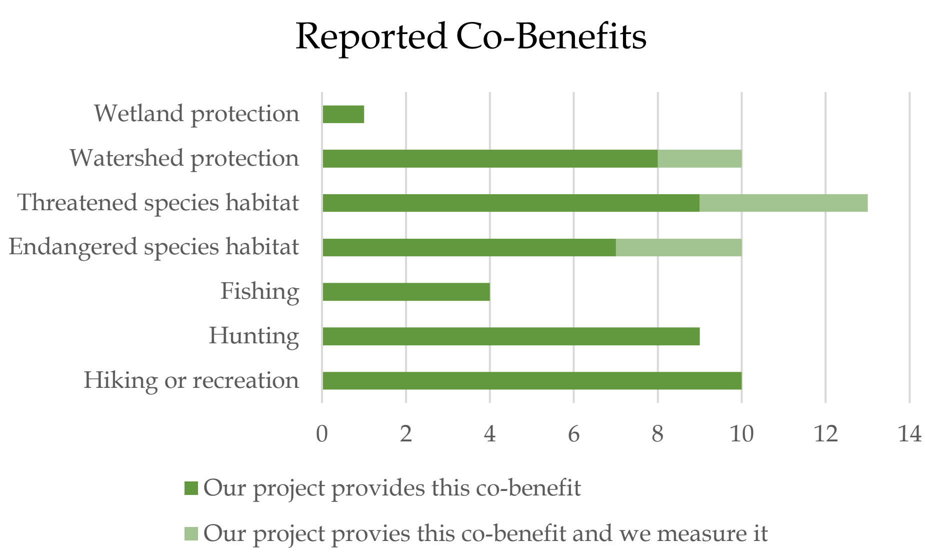

Figure 8. Survey Responses from 17 Forest Owners on project co-benefits.

No project operators or developers that we interviewed or surveyed were interested in additional reporting requirements, on co-benefits or otherwise, although at least one noted that if nationally standardized tracking metrics were developed, the reporting burden to California would be manageable. Respondents were concerned that reporting requirements are already onerous, so any future co-benefit reporting would likely need to have clear benefits for project operators and the state. We note that higher expected carbon prices might alter these assessments.

Finding #4: California Offsets Have Broken New Ground, but Regulatory Risks Hamper Further Development

Transitioning Into a More Mature Policy and Marketplace

The California forest offset program is currently in somewhat of an interstitial period, having traveled far up the learning curve of forest carbon policy experimentation, but still beset with uncertainty about the future. Unlike some other protocols the IFM and avoided conversion portions of the forest offset program have experienced notable project uptake. These areas have delivered emissions reductions and credits used by compliance entities and stand ready to deliver more in the future. Yet judging by the lengthy project listings and the persistently low price of offsets beneath an already low allowance price floor, the offset market seems to be in somewhat of a holding pattern while market participants wait to see how California policymakers chart a climate policy course past 2020.

Survey and interview results tend to confirm these indications. As detailed below, although ARB generally receives good marks in its program implementation thus far, market participants do not have the policy certainty they need to continue growing the program with more participating projects.

Bright Spots: Readiness and Program Experience

Although the price of allowances since 2013 has never risen high enough to necessitate the use of offsets as a cost-containment mechanism,[61] California's unprecedented innovation in developing a compliance-quality program and protocol for forest carbon offsets has resulted in a marketplace with dozens of credited projects. It is possible that many more could participate in the future. Projects that are now marginally economic at a carbon price of around $10/ton could be brought into the program in the future if the price rises. If the carbon price rises significantly, it is

[61] Cullenward and Coghlan, *supra* note 15 at 7.

possible that whole project types that are not currently financially attractive, such as reforestation projects and urban forest projects, may become economically viable.

In addition, ARB has received generally encouraging reviews in both survey and interview responses collected for this study. Of 17 responses, only three project owners expressed dissatisfaction with ARB's handling of the program overall, and only two expressed dissatisfaction with individual project application handling. Only two owners expressed that they would not consider expanding or bringing new land into the program in the future, while more than half of respondents expressed interest in the possibility. These results are conveyed in Figures 9, 10 and 11 below. When asked a narrative question about whether their satisfaction levels with ARB had changed over time though, responses were mixed. Some project owners remarked that ARB's project application reviews had become less predictable and more cautious, and others hypothesized that application interactions had become more frustrating because of an increase in application volume without an increase in ARB processing capacity. (Interestingly, no project owner expressed dissatisfaction with their developer or their registry, although at least one interviewee did indicate having markedly different impressions of two developer entities, one negative and one positive.)

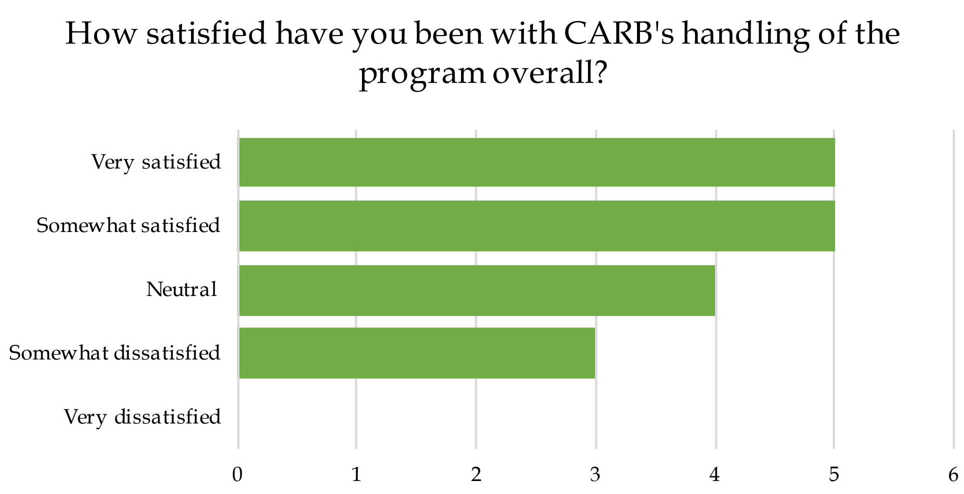

Figure 9. Survey Responses from 17 Forest Owners on CARB's performance.

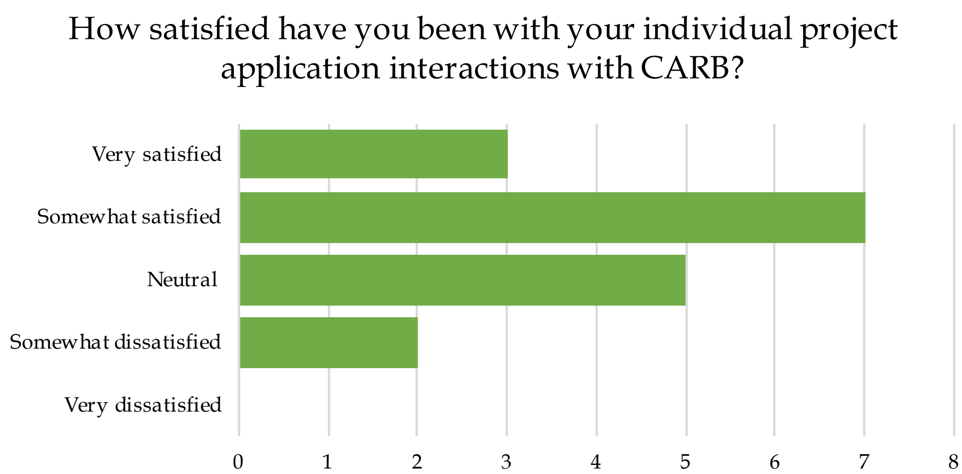

Figure 10. Survey Responses from 17 Forest Owners on CARB's application handling.

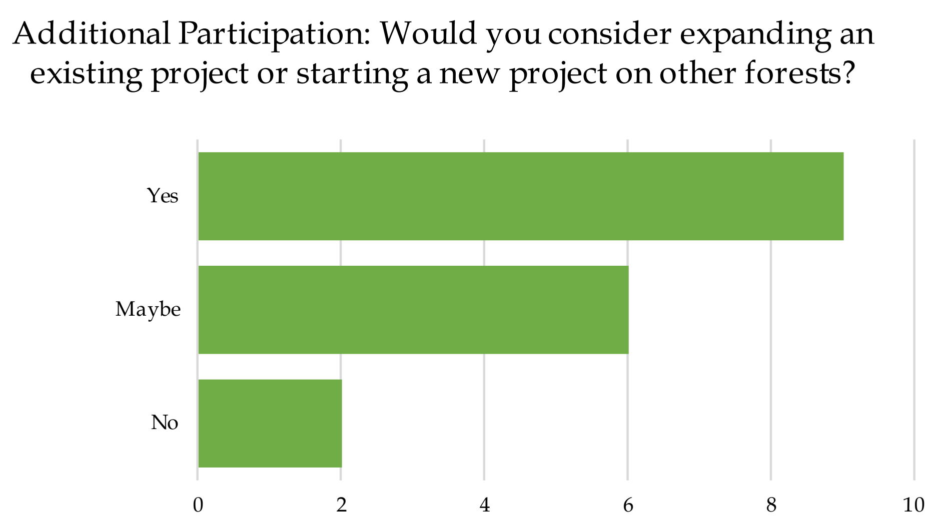

Figure 11. Survey Responses from 17 Forest Owners on additional participation.

Project developers were less sanguine in their appraisal, however. Only one respondent indicated satisfaction with the program (the others had neutral feelings), and divergent satisfied/unsatisfied opinions were reported about individual project interactions. All expressed that their satisfaction had changed over time, with two voicing concern that inefficiencies and the expense of meeting program requirements had not improved.

Both project developers and owners agreed in their general praise for CARB's approach to project risks. Two of three developers and 16 of 17 project owners reported that CARB has been appropriately accounting for project risks through the individualized project assessment and buffer pool requirements. The lonely dissenters took issue with 20% as the standard buffer pool credit contribution and advocated an individualized fire risk assessment for a particular project, respectively, but generally speaking ARB's approach to risk was reportedly appropriate in the eyes of market participants. Although the subject came up in some interviews, only one developer and one project owner reported being concerned about invalidation risks in their surveys.

Concerns: Instability, Carbon Price Uncertainty and Rising Verifier Costs

Project owners have much more divergent opinions about what the future may hold for the offset program, reflecting the general uncertainty about state policy and carbon prices that have the offset program in somewhat of a holding pattern. Although the state has committed to continuing climate programs in some form after the year 2020 with the passage and signing of Senate Bill 32 in 2016,[62] program participants report not being sure yet whether this new policy commitment will impact the return from their current projects. Figure 12 below presents the results from a survey question asked of offset project owners, reflecting their unresolved uncertainty in the wake of SB 32. This uncertainty may help explain the six 'maybe' answers reported above with respect to additional participation in the program – so much depends on the next few steps state policymakers take in extending the cap-and-trade program (or not), that possible future projects may simply wait until there is more certainty about the future of the program.

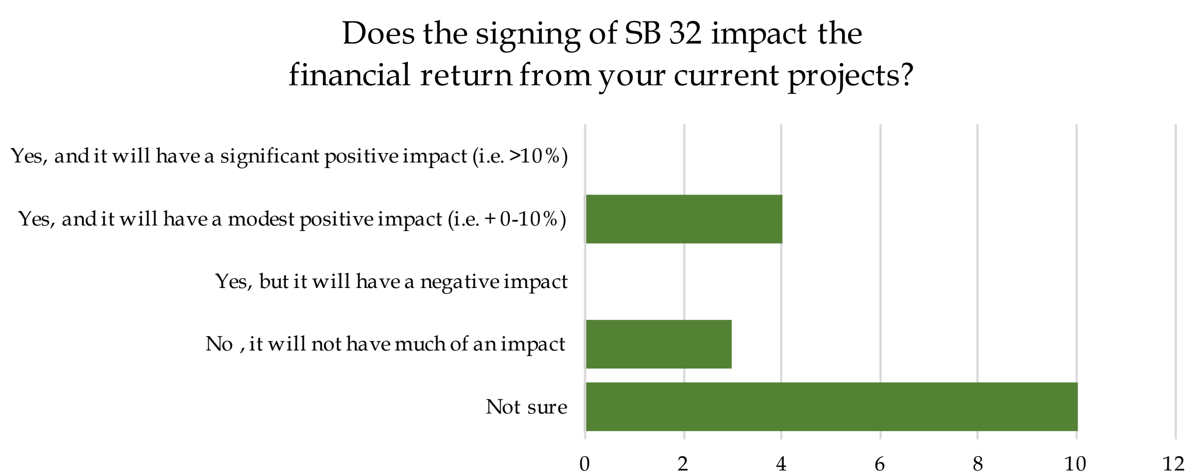

Figure 12. Survey Responses from 17 Forest Owners on the impact of Senate Bill 32.

[62] *See* Chris Megerian and Liam Dillon, *Gov. Brown Signs Sweeping Legislation to Combat Climate Change* L.A. TIMES (September 8, 2016), *available at* https://goo.gl/ewXwbN (describing SB 32).

Project owners generally seem optimistic about future price trends, assuming policy stability is provided. An open-ended narrative question on the project owner survey elicited many responses that cited program complexity, changing regulations and future policy uncertainty as major barriers in the program. But, when asked in an anonymous portion of the survey for their opinions about future price trends, project owners in general expressed bullishness and confidence about both near and longer term price trends. As seen in Figures 13 and 14 below, a 60% majority of respondents thought average sale prices for offsets would increase slightly in the time before 2020, and a majority believed they would rise slightly or significantly after 2020 as compared to today. However, when read together with the more cautious additional participation responses and concerns about policy certainty and complexity, this optimism may not translate to deeper program participation without more stability.

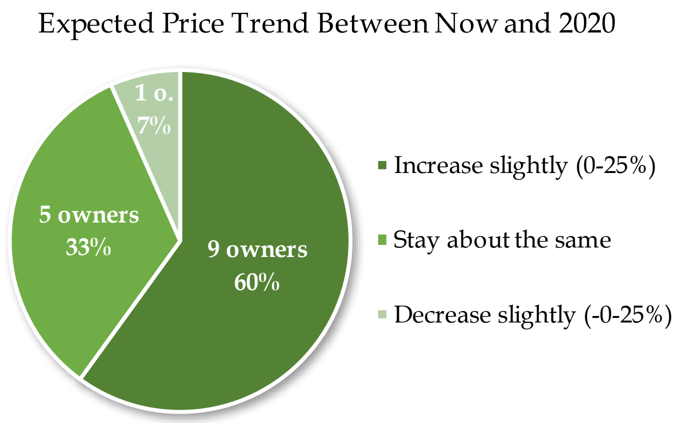

Figure 13. Survey Responses from 15 project owners re: near term price trend expectations

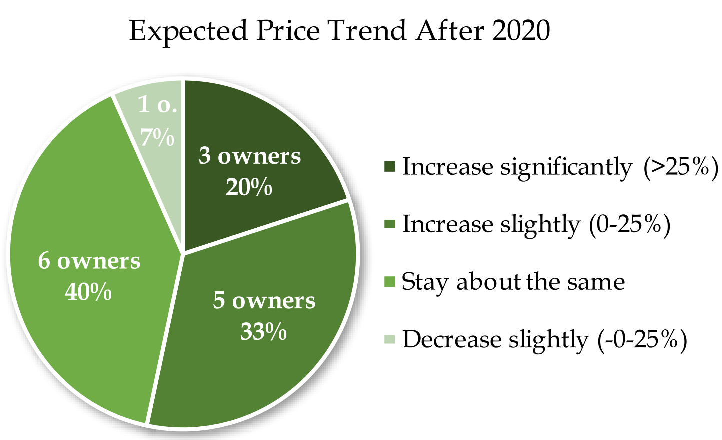

Figure 14. Survey Responses from 15 project owners re: longer term price trend expectations

While owners were conditionally bullish about future price trends, a worry that was repeatedly raised in multiple interviews and in survey data as well was rising verification costs. Other answers to the barriers question cited the steep and rising costs of monitoring and verification. In response to a question asking for their opinion of published verification and monitoring costs appearing in Kerchner and Keeton,[63] several respondents with recent verification cost experience stated that the published verification costs were much lower than actual costs. While opinions on that question were somewhat mixed and included five 'I don't know' answers, multiple interviewees expressed the same concern about rising verification costs. Some speculated that invalidation risk concerns had increased the length of verifications and financial exposure of the verifiers. However, most interviewees who mentioned the subject indicated that the likely causes are a short supply of verifiers and verification bodies, and large demands of verification in a compliance program as compared to in the voluntary market. ARB staff have reported that expanded training opportunities for verifiers are on the way to address this shortage. But, these efforts may need to bear fruit in the nearer term in order to keep pending projects from being dissuaded from joining the program at current carbon prices.

[63] *See* Kerchner and Keeton, *supra* note 49 at 75 (reporting ~$8,000 annual monitoring costs plus $15,000 costs incurred every six and $27,000 every 12 years).

Lessons for Natural and Working Lands

The State of California is in the process of updating its climate scoping plan, which sets goals for GHG emissions in each state sector. For the first time, the scoping plan will cover the period to 2030 and will include goals for carbon on natural and working lands, including agricultural lands and forests.[64] The draft scoping plan sets as an overarching goal that natural and working lands would be an overall emissions sink rather than a source. There are a number of activities and plans associated with this goal. We offer several recommendations for the state's goals in natural and working lands based on its experience thus far managing land-based carbon through the forest offset program:

- **Lesson #1**: Rigor of approach to carbon accounting drives implementation cost

The Forest Offset Program requires a very rigorous approach to carbon accounting, estimating the exact tonnage of forest carbon present on individual project lands. This is currently achieved at the project level through forest inventory, growth and yield modeling, and third party verification.[65] Detailed accounting through these methods cannot be scaled statewide. This level of detailed accounting is appropriate and feasible when dealing with compact and contiguous project lands, but costly and infeasible to conduct on a statewide basis. The State should and does consider methods of carbon accounting on Natural and Working Lands that are significantly less onerous than the Forest Offset Program, but that are still meaningful in terms of measuring changes in emissions and carbon sinks.[66] This is a case in which the Forest Offset Program uses a method that works well, but cannot be used at the scale of Natural and Working Lands.

The Proposed Plan offers a scale-appropriate method for carbon accounting on lands in California. It indicates that an updated Natural and Working Lands emissions inventory presently underway "applies airborne and space-based technologies to monitor forest health and quantify emissions associated with land-based carbon."[67] Combining remotely-sensed data with ground-based data is a good approach to take at the scale of the state-wide inventory, and should be continued as the inventory is expanded in the coming years.

[64] California Air Resources Board, THE 2017 CLIMATE CHANGE SCOPING PLAN UPDATE: THE PROPOSED STRATEGY FOR ACHIEVING CALIFORNIA'S 2030 GREENHOUSE GAS TARGET (January 20, 2017), at 107-17, *available at* https://goo.gl/ZBkyCN. Hereafter 'Proposed Plan'.
[65] *See generally* 2015 Forest Offset Protocol, *supra* note 31.
[66] *See* Proposed Plan at 108.
[67] Proposed Plan at 108.

➢ **<u>Lesson #2</u>**: Transparency and Accessibility of Program Information

The Forest Offset Program produces voluminous data about carbon accounting, project details, and offset usage, and much of it is available to the public through CARB's website and project registries. However, these data are not easy to locate or interpret. Data sheets can be difficult to find online, and reporting categories change over time, making consistent comparison over time difficult. In this case, the Forest Offset Program is not using best practices, and based on this experience we recommend a more coordinated approach for Natural and Working Lands data transparency and accessibility.

A clear and pre-designed framework for reporting on Natural and Working Lands should be devised as a part of the Integrated Natural and Working Lands Climate Change Action Plan ("Action Plan").[68] This will avoid difficulty in reporting and evaluation later on. The Proposed Plan states that the California will "develop implementation tracking and performance monitoring systems for the Action Plan."[69] This is especially important and should be a high priority as reporting in the Natural and Working Lands sector requires complex multi-agency efforts.

➢ **<u>Lesson #3</u>**: Approaches to Uncertainty and Risk

Uncertainty: Emissions accounting on Natural and Working Lands, like that for forests, comes with fundamental risks and uncertainties. The designers of the Forest Offset Program developed a number of notable mechanisms to deal with risk and uncertainty in carbon accounting and carbon crediting. For uncertainty, the Forest Offset Program reduces credits earned proportional to the sampling error of an on-the-ground forest inventory.[70] A similar approach could be applied to data used for carbon accounting on Natural and Working Lands.

At present neither the Proposed Plan nor Appendix G refer to estimation of uncertainty in developing goals or in developing the Action Plan for Natural and Working Lands.[71] Including uncertainty estimates in ongoing modeling and in the Action Plan will help ensure that the State accomplishes its carbon sink goal for Natural and Working Lands. Including uncertainty estimates is also consistent with

[68] Proposed Plan at 114.
[69] Proposed Plan at 117.
[70] 2015 Forest Offset Protocol at 112.
[71] *See* Proposed Plan at 117; *see also* California Air Resources Board, PROPOSED PLAN: APPENDIX G, NATURAL AND WORKING LANDS MODELING (January 2017), *available at* https://goo.gl/axN6vS.

IPCC Good Practice Guidance.[72] This is a case in which the Forest Offset Program is using a successful practice that can be adapted for use on Natural and Working Lands.

Risk: For risk, the Forest Offset Program also reduces carbon crediting based on the estimated risk of fire, pests, and other 'reversal' risks – the risk of releasing forest carbon to the atmosphere over the life of the project.[73] Carbon credits deducted based on a project's risk rating are allocated to a buffer pool of credits, which can be used in case of carbon loss due to fire, disease, or other unintentional losses.

The Natural and Working Lands sector does not need an explicit buffer account because of its more general carbon sink goals (discussed below), but it does need to plan for unavoidable carbon reversals. The Proposed Plan rightly acknowledges that "recent trends indicate that significant pools of carbon [are at] risk [of] reversal," and that climate change may exacerbate these risks, especially for wildland fire.[74] Risk should be explicitly incorporated into ongoing Natural and Working Lands modeling to ensure that the State meets its goals for the sector. We recommend adapting the buffer pool approach used in the Forest Offset Program and 'buffer' the Action Plan with activities that would exceed the State's carbon sink goal. This would ensure a 'contingency fund' of emissions reductions and enhanced sinks in case of 'reversal'. Risk estimations could be improved over time as improved data and modeling are available. At present, the Proposed Plan and Appendix G do not discuss accounting for risk in GHG emissions goal-setting for Natural and Working Lands.

- **<u>Lesson #4</u>**: Setting a Broad Carbon Sink Goal is Advisable

The experience of the Forest Offset Program shows that modeling future carbon stock, even at the project scale, is a difficult task. Land-based carbon stocks carry risk and uncertainty, as discussed above. The Forest Offset Program dealt with risk by carefully measuring carbon and creating a forest buffer pool—a sort of insurance pool or contingency fund of carbon credits to be used in case of unintentional loss of carbon. The Forest Offset Program further ensures accuracy by requiring multiple levels of verification. While measurement methods for Natural and Working Lands should continue to take advantage of improvements in remote sensing and ground-based data, the method of detailed ton-by-ton carbon accounting used by the Forest Offset Program is not currently feasible at a statewide scale.

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[72] *See generally* Intergovernmental Panel on Climate Change, 2013 REVISED SUPPLEMENTARY METHODS AND GOOD PRACTICE GUIDANCE ARISING FROM THE KYOTO PROTOCOL at 2.57-2.60 (Section 2.4.3 'Uncertainty Assessment'), *available at* https://goo.gl/bJWwZW.
[73] 2015 Forest Offset Protocol, *supra* note 31 at 131-36.
[74] Proposed Plan at 108.

The Proposed Plan states that "California's climate objective of natural and working lands is to maintain them as a carbon sink (i.e., net zero or even negative GHG emissions)."[75] The Proposed Plan rightly acknowledges that "the State's lands, as well as sub-tidal waters, can be both a source and a sink for GHG emissions."[76] The State's goal of maintaining Natural and Working Lands as a carbon sink is an appropriate one. An alternative goal would be to specify a particular percentage or numerical decrease in emissions and/or increase in sinks on Natural and Working Lands. Such an exact goal would be inappropriate because it would necessitate many of the onerous measurements and verification activities pursued under project-based programs like the Forest Offset Program, which are impractical for statewide inventories, as mentioned above. Also, measuring carbon in some sectors of Natural and Working Lands (such as soils) remains quite difficult. The overall 'carbon sink' goal is less precise but is also therefore feasible to both measure and attain in a statewide inventory.

While we support the overall 'carbon sink' goal for Natural and Working Lands, we recommend that the Proposed Plan clarify whether this is a cumulative or annual goal covering the years between now and 2030. There is likely to be considerable year-to-year variability in emissions from Natural and Working Lands, due to fire and other natural causes. The goal is referred to as cumulative on page 109 of the Proposed Plan, but the measure is not specified in the initial statement of the goal.[77] The Initial Scoping Plan (2008) set a specific annual goal for forest carbon sequestration, [78] and this goal has been difficult to measure and attain on an annual basis.

- **<u>Lesson #5</u>**: The Offsets Program Does Not Measure Co-Benefits, But Many Are Clearly Delivered

In part because the Forest Offset Program has stringent and detailed carbon accounting requirements, it was not practical, at least in initial years of the program, to require additional accounting of individual project co-benefits. As detailed in the attached report, we advise that the Forest Offset Program now take up 'no cost' opportunities for co-benefits reporting. Co-benefits reporting is even more feasible and important for Natural and Working Lands. Because the Natural and Working Lands goals and accounting can take advantage of remotely sensed data, and can tolerate

[75] Proposed Plan at 107.
[76] Proposed Plan at 108.
[77] Proposed Plan at ES5, 107.
[78] California Air Resources Board, CLIMATE CHANGE SCOPING PLAN: A FRAMEWORK FOR CHANGE (December 2008) at 64-65, *available at* https://goo.gl/UFhkyT.

greater uncertainty in acre-level carbon data, state agencies should be able to collect data and account for carbon *and* co-benefits.

The Proposed Plan rightly notes that policies must advance both carbon sequestration and co-benefits[79] and states that "strategies that reduce GHG emissions or increase sequestration in the natural and working lands sector often overlap and result in synergies with other sectors."[80] Accounting for these co-benefits will allow the state to measure the synergies and efficiency gains it is earning by implementing policies that have win-win benefits for carbon, water, agriculture, biomass utilization, land restoration, and conservation. As the State develops tracking and monitoring systems for Natural and Working Lands, these co-benefits should be included. In the Proposed Plan section for 'Scoping and Tracking Progress',[81] the text should be amended to read, "develop implementation tracking and performance monitoring systems for the Action Plan, *[including accounting of carbon and other co-benefits].*"[82]

[79] Proposed Plan at 107.
[80] Proposed Plan at 110.
[81] Proposed Plan at 116-17.
[82] Proposed insertion in brackets. *See* Proposed Plan at 117.

Appendixes

Below are two appendixes that provide more information about the sources, methods, and findings of this analysis. The first appendix presents a list of the 39 projects for whom we compiled and analyzed project design document information. The second appendix presents the list of entities who were reported as retiring forest offsets from 2013-15, and the forest offset projects those offsets came from.

Appendix I – Projects Included in Design Document Analysis

	ARB Project ID #	Project Name	State	Type of Protocol	Registry[83]	Project Documentation Locator
1	CAFR0030	Blue Source – Francis Beidler Improved Forest Management Project	SC	Early Action	CAR	CAR683
2	CAFR0087	Finite Carbon – Brosnan Forest	SC	Early Action	CAR	CAR658
3	CAFR0063	Green Assets – Middleton Avoided Conversion	SC	Early Action	CAR	CAR749
4	CAFR5034	Finite Carbon – The Forestland Group CT Lakes	NH	Compliance	ACR	ACR199
5	CAFR0088	Finite Carbon – Shannondale Tree Farm	MO	Early Action	CAR	CAR780
6	CAFR5089	Finite Carbon – The Forestland Group Champion Property IFM	NY	Compliance	CAR	CAR1088
7	CAFR5029	Green Assets-Brookgreen Gardens Improved Forest Management Project	SC	Compliance	ACR	ACR192
8	CAFR5016	Miller Forest	CA	Compliance	ACR	ACR189

[83] CAR = Climate Action Reserve; ACR = American Carbon Registry

9	CAFR0070	Finite Carbon – Berry Summit	CA	Early Action	CAR	CAR1004
10	CAFR0049	The Van Eck Forest	CA	Early Action	CAR	CAR101
11	CAFR0064	Yurok Tribe Sustainable Forest Project	CA	Early Action	CAR	CAR777
12	CAFR0029	Blue Source – Alligator River Avoided Conversion	NC	Early Action	CAR	CAR497
13	CAFR5043	Blue Source – Goodman Improved Forest Management Project (Michael Hart)	WI	Compliance	ACR	ACR202
14	CAFR5028	Round Valley Indian Tribes Improved Forest Management Project	CA	Compliance	ACR	ACR173
15	CAFR0040	Garcia River Forest	CA	Early Action	CAR	CAR102
16	CAFR5096	Brushy Mountain	CA	Compliance	CAR	CAR1095
17	CAFR0041	Big River / Salmon Creek Forests	CA	Early Action	CAR	CAR408
18	CAFR0042	Gualala River Forest	CA	Early Action	CAR	CAR660
19	CAFR0001	Willits Woods	CA	Early Action	CAR	CAR661
20	CAFR0116	Finite Carbon – NEFF (New England Forestry Foundation)	NH	Early Action	CAR	CAR672
21	CAFR5072	White Mountain Apache Tribe Forest Carbon Project	AZ	Compliance	ACR	ACR211

22	CAFR5095	Ashford III	WA	Compliance	CAR	CAR1094
23	CAFR0058	Virginia Conservation Forestry Program – Clifton Farm	VA	Early Action	CAR	CAR686
24	CAFR0057	Virginia Conservation Forestry Program – Rich Mountain	VA	Early Action	CAR	CAR696
25	CAFR5037	Virginia Highlands I	VA	Compliance	CAR	CAR1032
26	CAFR0103	Finite Carbon – MWF Brimstone IFM Project I	TN	Early Action	CAR	CAR582
27	CAFR0073	McCloud River	CA	Early Action	CAR	CAR429
28	CAFR5055	Buckeye Forest Project	CA	Compliance	CAR	CAR1013
29	CAFR0100	Rips Redwoods	CA	Early Action	CAR	CAR1015
30	CAFR5076	Trinity Timberlands University Hill Improved Forest Management Project	CA	Compliance	CAR	CAR1046
31	CAFR0031	Blue Source – Pocosin Lakes Forest Conservation Project (Avoided Conversion)	NC	Early Action	CAR	CAR676
32	CAFR5084	Finite Carbon – Potlatch Moro Big Pine CE IFM	AR	Compliance	CAR	CAR1086
33	CAFR0002	Finite Carbon Farm Cove Community Forest Project	ME	Early Action	CAR	CAR657
34	CAFR0026	Blue Source – Pungo River Forest Conservation	NC	Early Action	CAR	CAR659

		Project (Avoided Conversion)				
35	CAFR0027	Blue Source – Noles South Avoided Conversion Forest Project	NC	Early Action	CAR	CAR802
36	CAFR0028	Blue Source – Noles North Avoided Conversion Forest Project	NC	Early Action	CAR	CAR688
37	CAFR5003	Blue Source- Bishop Improved Forest Management Project	MI	Compliance	CAR	CAR973
38	CAFR5011	Yuork Tribe/Forest Carbon Partners CKGG Improved Forest Management Project	CA	Compliance	CAR	CAR993
39	CAFR5012	Hanes Ranch Forest Carbon Project	CA	Compliance	ACR	ACR182

Appendix II – Compliance Entities Using Offset Credits

This information is drawn from the Compliance Reports available on the CARB website at https://goo.gl/m61Kj1, and matched with data from project design documents for the projects listed in Appendix I above.

Compliance Entities Retiring Forest Offsets, 2013-15

California Cap-and-Trade Compliance Offset Program: Retired Forest Offsets by Compliance Obligation Entity			
For Offsets Redeemed 2013-2015			
CARB Entity ID	**Compliance Obligation Entity**	**# of Forest Projects Obtained From**	**Number of Retired Credits**
CA1248	AES Alamitos, LLC	2	100,105
CA1089	Air Products and Chemicals, Inc.	1	96,601
CA1281	Algonquin Power Sanger, LLC	1	1,620
CA1328	Applied Energy, LLC - NAS North Island	3	16,605
CA1406	California Dairies, Inc.	1	10,140
CA1119	Calpine Energy Services, LP	4	686,178
CA1592	Carson Cogeneration Company	1	1,378
CA2039	Chevron Power Holdings, Inc.	1	49,187
CA1075	Chevron U.S.A., Inc.	10	4,019,283
CA1101	City of Glendale	1	17,649
CA1370	Coalinga Cogeneration Company	1	30,730
CA1311	Double C Limited	1	347
CA1183	Dynegy Moss Landing, LLC	2	165,460
CA1742	Energia Azteca X, S.A. de C.V. and Energia de Baja California S. de R.L. de C.V. (La Rosita Power Marketing)	1	9,814
CA1234	Fresno Cogeneration Partners, LP	1	1,298
CA1070	GenOn Energy Management, LLC	1	7,667
CA1116	GWF Energy, LLC	1	20,867
CA1291	High Desert Power Project, LLC	1	125,000
CA1307	High Sierra Limited	1	353
CA1253	Ingomar Packing Company, LLC	1	5,841
CA1312	Kern Front Limited	1	318
CA1343	Kern River Cogeneration Company	2	102,040
CA1017	La Paloma Generating Company, LLC	4	74,356

CA1552	Macpherson Oil Company	1	17,516
CA1077	Mariposa Energy, LLC	1	3,344
CA1476	Martinez Cogen Limited Partnership	1	9,630
CA1367	Mid-Set Cogeneration Company	1	32,547
CA1107	Midway Sunset Cogeneration Company	1	39,478
CA1138	NRG Power Marketing, LLC	1	245,756
CA1137	OLS Energy - Chino	1	19,960
CA1046	Pacific Gas and Electric Company	1	61,495
CA2106	PBF Energy Western Region, LLC	3	140,179
CA1326	Praxair, Inc.	1	5,000
CA1925	Pro Petroleum, Inc.	1	35,000
CA1204	Rio Tinto Minerals Inc.	1	26,532
CA1136	Russell City Energy Company, LLC	1	39,964
CA1371	Salinas River Cogeneration Company	1	32,244
CA1085	San Diego Gas & Electric Company	1	27,602
CA1372	Sargent Canyon Cogeneration Company	1	32,987
CA1762	SEI Fuel Services, Inc.	3	103,840
CA1251	Shell Energy North America (US), LP	2	209,000
CA1029	Southern California Edison Company	5	501,170
CA1338	Sycamore Cogeneration Company	1	100,608
CA1165	Tesoro Refining & Marketing Company, LLC	10	1,488,172
CA1325	The Procter & Gamble Paper Products Company	1	25,691
CA1195	TransAlta Energy Marketing (U.S.), Inc.	1	6,773
CA1057	Ultramar, Inc.	1	13,857
CA1419	Union Pacific Railroad Company	1	38,184
CA1056	Valero Refining Company-California, Benicia Refinery and Asphalt Plant	3	103,112
CA1590	Valley Electric Association, Inc.	2	813
		Grand Total	**8,903,291**

Compliance Entities and The Forest Offsets They Buy

Forest Offsets -- Retired Credits by Compliance Obligation Entity and Project Name

Compliance Entities and Forest Offset Projects	# of Listings in Compliance Report	Total Quantity
AES Alamitos, LLC	2	100,105
Blue Source – Francis Beidler IFM Project	1	94,705
Hanes Ranch Forest Carbon Project	1	5,400
Air Products and Chemicals, Inc.	1	96,601
Blue Source-Bishop IFM Project	1	96,601
Algonquin Power Sanger, LLC	1	1,620
Blue Source – Pungo River Forest Conservation Project	1	1,620
Applied Energy, LLC - NAS North Island	5	16,605
Finite Carbon – Shannondale Tree Farm	1	2,077
Green Assets – Middleton Avoided Conversion	3	11,687
Round Valley Indian Tribes IFM Project	1	2,841
California Dairies, Inc.	1	10,140
Garcia River Forest	1	10,140
Calpine Energy Services, LP	8	686,178
Finite Carbon – The Forestland Group CT Lakes	1	275,000
Hanes Ranch Forest Carbon Project	1	70,349
Trinity Timberlands University Hill IFM Project	1	222,398
Willits Woods	5	118,431
Carson Cogeneration Company	1	1,378
Green Assets – Middleton Avoided Conversion	1	1,378
Chevron Power Holdings, Inc.	1	49,187
Blue Source-Bishop IFM Project	1	49,187
Chevron U.S.A., Inc.	38	4,019,283
Blue Source – Francis Beidler IFM Project	3	250,000
Blue Source – Goodman IFM Project	1	693,615
Blue Source – Noles North Avoided Conversion Forest Project	6	14,795
Blue Source – Noles South Avoided Conversion Forest Project	6	14,090
Blue Source – Pungo River Forest Conservation Project	6	21,115
Blue Source-Bishop IFM Project	2	379,649

Brushy Mountain	2	1,250,441
Finite Carbon – The Forestland Group Champion Property IFM	1	678,550
Finite Carbon Farm Cove Community Forest Project	1	146,666
Willits Woods	10	570,362
City of Glendale	1	17,649
Big River / Salmon Creek Forests	1	17,649
Coalinga Cogeneration Company	2	30,730
Blue Source-Bishop IFM Project	2	30,730
Double C Limited	1	347
Willits Woods	1	347
Dynegy Moss Landing, LLC	4	165,460
Buckeye Forest Project	1	100,000
Willits Woods	3	65,460
Energia Azteca X, S.A. de C.V. and Energia de Baja California S. de R.L. de C.V. (La Rosita Power Marketing)	1	9,814
Garcia River Forest	1	9,814
Fresno Cogeneration Partners, LP	1	1,298
Willits Woods	1	1,298
GenOn Energy Management, LLC	2	7,667
Willits Woods	2	7,667
GWF Energy, LLC	3	20,867
Willits Woods	3	20,867
High Desert Power Project, LLC	2	125,000
Finite Carbon – The Forestland Group CT Lakes	2	125,000
High Sierra Limited	1	353
Willits Woods	1	353
Ingomar Packing Company, LLC	1	5,841
Green Assets – Middleton Avoided Conversion	1	5,841
Kern Front Limited	1	318
Willits Woods	1	318
Kern River Cogeneration Company	4	102,040
Blue Source-Bishop IFM Project	2	86,918
Willits Woods	2	15,122
La Paloma Generating Company, LLC	4	74,356
Finite Carbon – Brosnan Forest	1	1,314

McCloud River	1	15,038
Trinity Timberlands University Hill IFM Project	1	10,473
Willits Woods	1	47,531
Macpherson Oil Company	1	17,516
Green Assets – Middleton Avoided Conversion	1	17,516
Mariposa Energy, LLC	1	3,344
Willits Woods	1	3,344
Martinez Cogen Limited Partnership	1	9,630
The Van Eck Forest	1	9,630
Mid-Set Cogeneration Company	2	32,547
Blue Source-Bishop IFM Project	2	32,547
Midway Sunset Cogeneration Company	1	39,478
Willits Woods	1	39,478
NRG Power Marketing, LLC	4	245,756
Gualala River Forest	4	245,756
OLS Energy - Chino	2	19,960
Blue Source – Francis Beidler IFM Project	2	19,960
Pacific Gas and Electric Company	1	61,495
Willits Woods	1	61,495
PBF Energy Western Region, LLC	9	140,179
Big River / Salmon Creek Forests	3	52,762
Garcia River Forest	1	48,456
The Van Eck Forest	5	38,961
Praxair, Inc.	1	5,000
Virginia Conservation Forestry Program – Clifton Farm	1	5,000
Pro Petroleum, Inc.	1	35,000
Big River / Salmon Creek Forests	1	35,000
Rio Tinto Minerals Inc.	1	26,532
Big River / Salmon Creek Forests	1	26,532
Russell City Energy Company, LLC	1	39,964
Willits Woods	1	39,964
Salinas River Cogeneration Company	2	32,244
Blue Source-Bishop IFM Project	2	32,244

San Diego Gas & Electric Company	2	27,602
Trinity Timberlands University Hill IFM Project	2	27,602
Sargent Canyon Cogeneration Company	2	32,987
Blue Source-Bishop IFM Project	2	32,987
SEI Fuel Services, Inc	1	28,756
Finite Carbon – MWF Brimstone IFM Project I	1	28,756
SEI Fuel Services, Inc.	2	75,084
Finite Carbon – Shannondale Tree Farm	1	35,084
Green Assets – Middleton Avoided Conversion	1	40,000
Shell Energy North America (US), LP	2	209,000
Blue Source-Bishop IFM Project	1	84,000
Miller Forest	1	125,000
Southern California Edison Company	5	501,170
Blue Source – Francis Beidler IFM Project	1	30,295
Finite Carbon – The Forestland Group CT Lakes	1	125,000
Hanes Ranch Forest Carbon Project	1	6,548
Round Valley Indian Tribes IFM Project	1	241,164
Trinity Timberlands University Hill IFM Project	1	98,163
Sycamore Cogeneration Company	2	100,608
Blue Source-Bishop IFM Project	2	100,608
Tesoro Refining & Marketing Company, LLC	11	1,488,172
Blue Source – Francis Beidler IFM Project	1	908
Finite Carbon – Berry Summit	1	193,277
Finite Carbon – Shannondale Tree Farm	1	50,000
Finite Carbon – The Forestland Group CT Lakes	1	316,601
Green Assets – Middleton Avoided Conversion	2	50,000
Green Assets-Brookgreen Gardens IFM Project	1	160,000
McCloud River	1	65,000
Miller Forest	1	94,084
Trinity Timberlands University Hill IFM Project	1	13,209
White Mountain Apache Tribe Forest Carbon Project	1	545,093
The Procter & Gamble Paper Products Company	1	25,691
Blue Source-Bishop IFM Project	1	25,691

TransAlta Energy Marketing (U.S.), Inc.	1	6,773
McCloud River	1	6,773
Ultramar, Inc.	1	13,857
Blue Source – Francis Beidler IFM Project	1	13,857
Union Pacific Railroad Company	1	38,184
Finite Carbon – Brosnan Forest	1	38,184
Valero Refining Company-California, Benicia Refin. and Asphalt Plant	3	103,112
Blue Source – Francis Beidler IFM Project	1	36,143
Finite Carbon Farm Cove Community Forest Project	1	48,888
Willits Woods	1	18,081
Valley Electric Association, Inc.	2	813
Blue Source-Bishop IFM Project	1	5
The Van Eck Forest	1	808
	Grand Total	**8,903,291**

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Designing efficient markets for carbon offsets with distributional constraints

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ABSTRACT

This paper presents an assessment of the relative efficacy of three key instruments – baselines, trade ratios and limits - which are under policy discussion in the design of carbon offset programs. We rank the instruments by their implications for total emissions, economic efficiency, and efficiency gain relative to a distributional transfer from capped to uncapped sectors. We find that the baseline is the best instrument for maximizing welfare as it directly reduces the share of offsets that are non-additional and that second-best policies do not sacrifice much welfare relative to the standard first-best policy prescription.

Introduction

The design of markets for carbon offsets from unregulated sectors, to complement cap-and-trade programs in regulated sectors, is a central issue in environmental and climate policy. Such markets could, if designed appropriately, reduce the overall economic costs of climate change mitigation programs (Fell et al., 2012; Kollmuss et al., 2010). Allowing capped sectors to use offsets essentially broadens the affected sources that are able to reduce emissions. When capped and uncapped sources of emissions are open to trade emissions credits in the form of carbon offsets, a reduction target can be achieved at a lower cost relative to a program that does not let the uncapped sector opt in (Newell et al., 2013; Bushnell, 2012).

This form of cost containment, however, may break the cap established for regulated sources if the mitigation from uncapped sources would have happened in the absence of the program. The problem of non-additionality, or the awarding of carbon offsets to uncapped sources that do not perform mitigation, is a central source of criticism because of its adverse emissions consequences (Newell et al., 2013; Bushnell, 2012). The problem stems from the fact that programs cannot fully observe business-as-usual (BAU) emissions from uncapped sources, since these emissions are a hypothetical that never takes place if the source opts in. If the source would have reduced emissions anyway, then it is awarded non-additional offsets that are then sold to capped sources. The non-additional offsets contribute toward an increase in overall emissions,

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even if economic efficiency improves because of the additional offsets. This non-additionality, often discussed in terms of the integrity of the cap, is a major worry for key stakeholders, and thus for policy makers.

There is a well-known solution to this problem of cap integrity. Programs can deal with non-additionality by tightening the cap on the regulated sector sufficiently that total emissions remain unchanged (Montero, 2000). However, this policy involves a transfer of rents from the capped sector (if permits are grandfathered) to the uncapped sector. As we will see later on in this paper, this transfer can be very large for the proposed federal cap-and-trade program in the United States. Our numerical calibrations suggest a transfer of the order of 30 percent of the pre-offsets market rent in the capped sector. Not surprisingly, these transfers will be resisted strongly by firms in the regulated sector.

There are three key alternative methods being discussed in the offsets policy area for handling the problem of additionality, including (i) more stringent emissions baselines for sources in the uncapped sector; (ii) trade ratios for offsets relative to allowances, where a unit of offset supplied from the uncapped sector translates into less than one unit of emissions permitted in the capped sector; and (iii) a limit on the use of offsets for compliance in the capped sector (Bushnell, 2012; Kollmuss et al., 2010). It should be obvious that each of these three instruments reduces the total supply of offsets, and hence the rent transfer from the capped sector. But the impact of each of these on the additional versus non-additional composition of offsets is not at all clear and requires careful analysis. Further, the compositional effect relative to the distributional effect for each of these instruments needs to be quantified. This leads then to the question addressed in this paper – which instrument is best, for which objective?

Recent studies have taken some first steps in analyzing the welfare and distributional implications of opt-in programs. Montero (2000) studies this problem in the context of the SO_2 opt-in provision where uncapped units were allowed to opt in and receive a quantity of allowances based on historical emissions. In a setting where units have private information on BAU emissions, the first best can be achieved by raising the allocation to uncapped units so that all of them opt in and lowering the permit allocation to capped units. Van Benthem and Kerr (2013) compare the efficacy of alternative methods for alleviating adverse selection in avoided deforestation programs. They find that increasing the scale of opt-in projects alleviates (and, in the limit, can eliminate) the problem of adverse selection. They also compare the efficacy of imposing trade ratios and adjusting offset project baselines. They find that an optimal policy includes a combination of a trade ratio and stringent baselines, a result that is consistent with our own findings. This study, however, does not evaluate the welfare implications of limiting the use of offsets and focuses its simulations on an international offsets scheme. Our study complements Van Benthem and Kerr (2013) by focusing on the efficiency and distributional implications of a domestic offset program.[1] Like Van Benthem and Kerr (2013), we document an important trade-off between efficiency gain and rent transfer. We evaluate this trade-off, however, for distinct domestic sectors (e.g., capped sectors including electricity generation, petroleum refining and cement manufacturing and uncapped sectors including agriculture and forestry). We find that different offsets policies lead to substantially different rent transfers between these sectors, making some offsets policies more politically feasible than others.

Millard-Ball (2013) evaluates the effectiveness of sectoral crediting mechanisms using a similar model of adverse selection. He shows that there exists a significant trade-off between efficiency and rent transfers, and that uncertainty in BAU emissions makes these mechanisms very poor methods for reducing emissions. This study, however, focuses on national transportation sectors and does not consider the relative efficiency of alternative instruments for dealing with additionality among individual offsets projects.

Our paper extends the literature in several ways. First, we extend prior analyses of adverse selection in opt-in emissions trading programs by deriving analytical welfare formulas for instruments currently being adopted in cap-and-trade programs. Our formulas allow us to make general statements about the differences between the instruments and to provide clear policy recommendations based on these differences.

Second, we provide an assessment of three instruments for the level and composition of offsets, holding constant the cap on the regulated sector. We then use this to conduct an analysis of the efficiency and distributional implications of each instrument. Furthermore, we compare policies based on efficiency and on rent transfers, which lead to critical trade-offs that we explore analytically and numerically. This exercise contrasts with existing literature that focuses solely on the efficiency aspect of different offset policies.[2]

Third, we numerically calibrate the analytical model to analyze federal U.S. greenhouse gas (GHG) cap-and-trade legislation as described in the 2009 Waxman–Markey bill. With our numerical model, we are able to compute the welfare and emissions impacts of alternative second-best policies. We are also able to compute the welfare cost associated with avoiding rents from being transferred across sectors to implement the first-best solution.

Our major findings are fourfold. Our first result suggests that coupling the instruments can achieve greater efficiency than using them individually. We find that the second-best policy couples a trade ratio less than one with a very stringent baseline. While a very stringent baseline eliminates most of the supply of non-additional offsets, it crowds out the supply of

[1] While there exist cap-and-trade programs that allow international offsets, there are several examples that only allow domestic sources to opt in, including the Regional Greenhouse Gas Initiative and the program under the California AB 32 Global Warming Solutions Act.

[2] While comparing the efficiency gains to the distributional implications is generally relevant for any environmental policy, it is especially important for designing markets for carbon offsets. In particular, the primary concern with the standard first-best mechanism presented in Montero (2000) is that there will be a potentially significant transfer of rents across sectors of the economy. If this rent transfer turns out to be small, then it may be feasible to implement in practice, which would make the discussion of second-best policies irrelevant.

additional offsets. The trade ratio is set below one to increase the price of offsets and boost up the supply of additional offsets. This mechanism may not be politically feasible as trade ratios less than one appear, independent of the other instrument choices, to increase aggregate emissions, as capped firms need less than one offset to account for one of its own emissions.

Our second result addresses the question of how the policy maker should set the three instruments when it cannot select a ratio less than one. In this setting, the baseline is the best instrument for maximizing welfare. When the baseline is set at its optimum level, the trade ratio should be set at one and the offsets limit should be non-binding. This is because adjusting the baseline attacks the problem of non-additionality directly, while the other two instruments can only approach the issue indirectly.

Third, comparing the three instruments, our numerical calculations show that the welfare cost per unit of avoided redistribution from the capped sector is the lowest for the baseline. However, the numerical value of this ratio is below standard estimates for the marginal excess burden of public funds. This result suggests that if the policy maker chooses among the policy options of sacrificing welfare to avoid one dollar of transfers or allowing the rent transfer to take place but compensate capped firms through revenues generated from a labor tax, they should choose the former as it is less costly per dollar of transfers.

Fourth, when the baseline instrument is not fully reliable, as in the case of international offsets, then the other two instruments come into their own. In this case, we show that the trade ratio instrument is superior to the limits instrument and that the efficient trade ratio is above one.

The plan of the paper is as follows. The Section "The analytical model" sets out the basic analytical model and derives analytical results as the basis for the numerical model. The section "The numerical model" develops the calibration of the numerical model for the US and presents the main results. The section "Further analysis" provides further analysis and the section "Conclusion" concludes.

The analytical model

In this section, we develop an analytical model to isolate the channels exploited by various instruments that regulate carbon offsets markets.

Model assumptions

The model has two sectors: a *capped sector* and an *uncapped sector*. Each sector includes a unit mass of firms that are capable of abating emissions. A policy maker controls emissions by establishing a cap-and-trade program requiring firms in the capped sector to hold a permit or an equivalent quantity of offsets for every unit of pollution they emit. The policy maker encourages uncapped firms to opt in by allowing them to sell offsets to capped firms.[3]

In our notation, the subscript $j=\{r,u\}$ denotes the capped and uncapped sector, respectively, while the superscript i denotes firm i. Pre-intervention levels of variables are further subscripted by 0. Emissions are denoted by the variable e. Thus e^i_{j0} is the emission level of firm i in sector j in the pre-intervention scenario. This is also the BAU level of emissions. Firm i in sector j has a marginal cost of abatement c^i_j.[4] This is assumed to be the same pre- and post-intervention. Thus the subscript 0 is suppressed. The values of e^i_{j0} and c^i_j are firm i's private information. The policy maker does not observe e^i_{j0} or c^i_j but observes density functions for each variable.

The policy intervention has two components. The policy maker establishes a cap-and-trade program by grandfathering A tradable permits to capped firms.[5] At the same time, the policy maker sets emissions baselines for uncapped firms, b^i. Baselines attempt to measure BAU emissions of uncapped firms and are used to reward these firms for sequestration or emissions reductions.[6] Capped firms observe their permit allocation and make abatement decisions and uncapped firms observe their emissions baseline and make offset supply decisions. Firms make decisions based on their own BAU emissions, marginal costs of abatement and market prices for permits and offsets.[7]

[3] There are several reasons why some sources are capped while others are not. The most prominent reason is because monitoring and verification costs for some sectors are substantially higher than they are in other sectors (Sigman, 2010). Other reasons include legal and political constraints and property rights issues (Hahn and Richards, 2010). Governing bodies generally have power to prevent harms (by preventing carbon emissions through abatement) but they cannot force the private production of benefits (by forcing emissions sequestration). The property rights issue involves international participation. While the United States, Europe and other developed countries may be willing to develop an emissions target, other countries may not. The US cannot force the participation of other countries, but it can encourage them to participate through an offsets program.

[4] We use the terminology marginal cost of abatement to represent the marginal cost of all forms of emissions mitigation, including emissions reductions and sequestration.

[5] We do not consider the possibility that permits are auctioned. In the most recent U.S. climate bill and in many existing cap-and-trade programs including California's program within the Global Warming Solutions Act, a large fraction of permits are freely allocated at the beginning of the programs.

[6] Setting a baseline is required for any opt-in policy. The credited reductions are determined by the agent's behavior in relation to the baseline. See Baumol and Oates (1988) for a formal theoretical treatment.

[7] These assumptions are consistent with Montero (2000). An alternative assumption would be that firms form expectations of market prices which would likely change capped and uncapped firm decisions depending on how the expectations are formed. To the best of our knowledge there does not exist evidence on how offset suppliers form price expectations. We adopt the simplest approach by assuming all firms observe all relevant market variables.

We assume that BAU emissions are drawn from a sector-specific probability density function with support $e^i_{j0} \in [\underline{e}_{j0}, \overline{e}_{j0}]$ where each e^i_{j0} is independently and identically distributed according to the cumulative distribution function $Y_j(e_{j0})$ with mean $\mathbb{E}(e_{j0})$. Marginal costs are constant and satisfy $c^i_j \in [\underline{c}_j, \overline{c}_j]$ and are independently and identically distributed according to the cumulative distribution function $Z_j(c_j)$.[8] To keep the model analytically tractable, we assume that the distributions are independent.[9] In addition to lowering emissions, uncapped firms can sequester emissions. We assume that each uncapped firm has the same sequestration potential of $\alpha \le 0$.[10]

Capped firm problem

We assume that capped firm i is grandfathered permits a^i_0.[11] We define the rent generated by the establishment of the cap-and-trade program as the equilibrium value of all of the permits allocated to capped firms. The rent generated from the grandfathering equals $p_e a^i_0$, where p_e is the equilibrium permit price.[12] Firm i uses permits to comply with the cap-and-trade program or the firm sells them to other firms.[13] In addition, the firm can buy offsets, f, or abate its emissions. Firm i minimizes compliance costs by choosing emission level e^i_r, permit transactions a^i and offset purchases f^i to solve for

$$\min_{\substack{0 \le e^i_r \le e^i_{r0} \\ a^i \ge -a^i_0 \\ f^i \ge 0}} \left\{ p_a a^i + p_f f^i + c^i_r (e^i_{r0} - e^i_r) \right\} \quad \text{subject to} \tag{1}$$

$$a^i + a^i_0 + f^i \ge e^i_r. \tag{2}$$

If $a^i < 0$, the firm is a net seller of permits, and if $a^i > 0$, it is a net buyer.[14] Permits are bought and sold at the equilibrium permit price, p_a, while offsets are bought at the equilibrium price p_f. The first-order conditions imply that the prices are equal in equilibrium:[15]

$$p_a = p_f. \tag{3}$$

Firms with marginal cost of abatement less than p_a will reduce emissions below their BAU emission levels. These firms will reduce their emissions down to zero. We suppress firm superscripts and express total abatement by the capped sector, denoted by q_r, as

$$q_r = \int_{\underline{c}_r}^{p_a} \int_{\underline{e}_{r0}}^{\overline{e}_{r0}} e_{r0} \, dY_r \, dZ_r. \tag{4}$$

Total abatement costs of the capped sector, denoted by C_r, are

$$C_r = \int_{\underline{c}_r}^{p_a} \int_{\underline{e}_{r0}}^{\overline{e}_{r0}} c_r e_{r0} \, dY_r \, dZ_r, \tag{5}$$

Note from these expressions that C_r can be written as a function of q_r, $C_r(q_r)$, by substituting out p_a.

Uncapped firm problem

Uncapped firms can opt in by voluntarily selling offsets to capped firms.[16] For an uncapped firm to generate an offset, the policy maker sets an emissions baseline for the firm. As the policy maker cannot observe firm-specific BAU emissions,

[8] Although individual firms have constant marginal costs, because marginal costs vary across firms, the aggregate marginal cost curves for each sector are not constant. Furthermore, in the analytical model and welfare formulas that we present below, we do not assume a specific distribution for marginal abatement costs. In our simulation we assume that the distribution for marginal costs of uncapped firms is uniform. This implies that the marginal cost curve for the uncapped sector is linear.

[9] Fell et al. (2012) demonstrate that correlations between marginal abatement costs between capped and uncapped sectors lead to small increase in compliance costs. Under the most extreme correlation considered, Fell et al. (2012) find that compliance costs are about nine percent higher than the case without correlation.

[10] We represent sequestration of emissions as a negative quantity so that net emissions equals the sum of emissions and sequestration.

[11] The integral summation of individual firm permit allocations equals the aggregate permit allocation, $\int a^i_0 di = A$.

[12] If all of the permits were to be auctioned, then capped sector rents would simply become government revenue. In this setting, government revenue adjusts under a policy prescription by the same amount that capped sector rents adjusts in the case that all permits are grandfathered.

[13] We abstract from dynamic aspects of cap-and-trade programs by considering a single compliance period. These aspects include permit banking and borrowing across compliance periods. Allowance banking and borrowing allow capped firms to smooth abatement costs over time by shifting emissions reduction responsibilities from one year to another. This mechanism has the effect of flattening the time path of emissions reductions and permit prices. See Rubin (1996) for a theoretical treatment of banking and borrowing. Fell and Morgenstern (2010) estimate the cost savings from allowing firms to bank and borrow permits.

[14] Firm i's solution is to abate its emissions if it has a marginal cost of abatement that is less than the equilibrium permit price. In the absence of market power and transaction costs, the program will minimize compliance costs among capped firms (Montgomery, 1972). Furthermore, the initial allocation of permits, a^i_0, will not influence the equilibrium, a manifestation of Coase's theorem (Coase, 1960). For studies that consider market power and transaction costs, see Hahn (1984) and Stavins (1995).

[15] In Section "The analytical model", we will show that this equilibrium condition is distorted when the policy maker introduces alternative instruments to regulate the supply of offsets.

[16] We do not distinguish between domestic and international offsets in our analytical model. We consider the case of international offsets in our sensitivity analysis when we expand the supply of offsets by adjusting down the upper bound of the uncapped sector marginal abatement cost distribution. We leave for a future exercise the joint determination of separate instruments for domestic and international offsets.

assigning baselines collapses to the decision of setting a common baseline for all uncapped firms.[17] We denote the common baseline by b.[18]

Uncapped firm i makes two decisions. First, the firm decides whether to opt in. Second, it makes an emissions choice. If firm i opts in, it solves the following problem:

$$\pi^i = \max_{\alpha \le e_u^i \le e_{u0}^i} \left\{ p_f(b - e_u^i) - c_u^i(e_{u0}^i - e_u^i) \right\}. \tag{6}$$

Firm i opts in if $\pi^i \ge 0$. If $\pi^i < 0$, then firm i does not opt in and chooses $e_u^i = e_{u0}^i$.

The general behavior of uncapped firms is illustrated in Fig. 1.[19] The horizontal axis measures marginal abatement costs of uncapped firms. The vertical axis measures BAU emissions of uncapped firms. The horizontal dashed line where BAU emissions equal α represents sequestration potential for all uncapped firms. Firms in area A_2 do not supply offsets because they have marginal costs of abatement that exceed the marginal return from supplying an offset, p_f. For firms with a marginal cost of abatement less than p_f, the decision to supply offsets depends on the relative magnitude of the firm's baseline b and its BAU emissions e_{u0}^i. The curve separating areas A_1 and A_3, denoted by $\pi = 0$, represents firms that are just indifferent to supplying offsets. The curve is obtained by substituting $e_u^i = \alpha$, setting the objective function in (6) equal to zero and isolating e_{u0}^i:

$$e_{u0}^i = \frac{p_f(b - \alpha) + c_u^i \alpha}{c_u^i}. \tag{7}$$

Firms in areas A_1 and A_2 do not supply offsets. Firms in areas A_3, A_4 and A_5 do supply offsets, but these have different implications for abatement. An offset is *additional* if it corresponds to actual abatement. Additional offsets are sold by firms in regions A_3 and A_4, as the firms in these regions sell offsets that are created by reducing emissions. We denote the total amount of these as q_u. An offset is *non-additional* if it does not correspond to abatement. These types of offsets are sold by suppliers with BAU emissions below the baseline that are able to claim offsets up to the baseline without actually reducing emissions. We denote the total amount of non-additional offsets by E_{NA}. Non-additional offsets are sold by firms in regions A_4 and A_5.[20] A firm that is characterized by the point $(c_u{''}, e_{u0}{''})$ opts in and earns additional and non-additional offsets since its BAU emissions fall below b and because it chooses to reduce its emissions further to $e_u{''} = \alpha$. But there also exists a quantity of abatement that does not create offsets. Firms in area A_3 contribute to this type of reduction, which we call *under-credited emissions reductions* and denote by E_{UC}.[21] The quantity of under-credited emissions reductions by a firm in region A_3 is given by the difference between the firm's BAU emissions and its baseline, $e_{u0}^i - b > 0$.[22] A firm that is characterized by the point (c_u', e_{u0}') opts in, is under-credited and earns additional offsets since its BAU emissions lie above b and because it chooses to reduce its emissions to $e_u' = \alpha$. We suppress firm superscripts and express total abatement by the uncapped sector, denoted by q_u, as

$$q_u = \int_{\underline{c}_u}^{p_f} \int_{\underline{e}_{u0}}^{\tilde{e}_{u0}} (e_{u0} - \alpha)\, dY_u\, dZ_u, \tag{8}$$

[17] We adopt this assumption for simplicity. Our results are insensitive to this assumption since the policy maker only observes the aggregate distribution of BAU emissions. In practice the policy maker can assign baselines at various scales, including assigning a baseline for an entire sector. See Kollmuss et al. (2010) for more details.

[18] In practice, baselines are assigned on a project-by-project basis and usually follow project-type protocols. (In the California AB 32 cap-and-trade program, there is a different protocol for the four project types that are currently allowed, including separate protocols for non-urban afforestation, urban afforestation, livestock and ozone depleting substances.) Our assumption of a common baseline is equivalent to a model where project-specific baselines are assigned as in Van Benthem and Kerr (2013), Millard-Ball (2013) and Bento et al. (2012). In each of these models, the policy maker observes a noisy measurement of BAU emissions for each project and assigns a baseline as a function of this measurement. As a consequence, projects with a measurement that is higher than their BAU emissions may be assigned a baseline that lies above its BAU emissions, as is the case for firms in areas A_4 and A_5 in our model. Projects with a measurement that is lower than their BAU emissions may be assigned a baseline that lies below its BAU emissions, represented by firms in areas A_1, A_2 and A_3 in our model. We represent the magnitude of the measurement noise in the models of Van Benthem and Kerr (2013), Millard-Ball (2013) and Bento et al. (2012) by the heterogeneity in uncapped firm BAU emissions. In both model types, the greater the measurement noise or heterogeneity in uncapped firm BAU emissions, the greater the supply of non-additional offsets, the lower the quantity of under-credited emissions reductions and the lower the supply of additional offsets.

[19] Uncapped firms have three possible actions: do not opt in, opt in and reduce their emissions, or opt in and do not reduce their emissions. Firms located in areas A_1 and A_2 do not opt in and perform no abatement; firms located in areas A_3 and A_4 decide to opt in and abate the maximum amount $e_{u0}^i - \alpha$; Firms located in A_5 opt in and perform no abatement.

[20] Firms in area A_4 sell both additional and non-additional offsets. These are firms that are over credited with non-additional offsets as the baseline is above their BAU emissions. These firms, however, also abate emissions because their marginal cost of abatement is less than the equilibrium offsets price. The firms earn additional offsets from these reduced emissions.

[21] The existence of these reductions has the effect of lowering aggregate emissions. In a companion paper, Bento et al. (2012) use a simulation analysis to investigate the relative magnitude of under-credited emissions reductions to non-additional offsets for different levels of offset prices and baseline stringency.

[22] Schneider (2009) discusses how various policy instruments, including adjusting baselines below BAU, can be used to achieve emissions reductions beyond those credited as offsets.

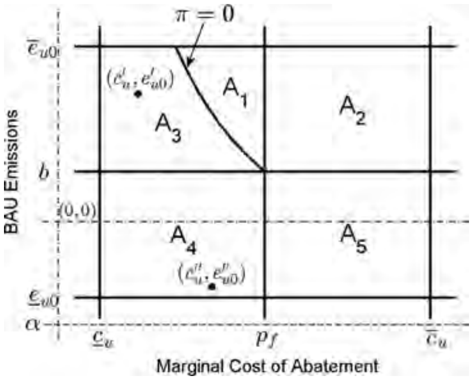

Fig. 1. Decisions of uncapped firms. Each uncapped firm is represented by a point within the regions of marginal costs of abatement and BAU emissions. The horizontal axis measures marginal cost of abatement, which range from $\underline{c}_u$ to $\overline{c}_u$. The vertical axis measures BAU emissions, which range from $\underline{e}_{u0}$ to $\overline{e}_{u0}$. Uncapped firms are categorized by five regions, denoted by $A_1, A_2,\ldots,A_5$. The regions represent distinct decisions and offset supplies of uncapped firms (see the text for a detailed explanation). These regions are bounded by the heavy black lines. For example, uncapped firms in region A_4 (such as a firm represented by point $(c_u'', e_{u0}''))$ have a marginal cost of abatement greater than or equal to $\underline{c}_u$ and less than or equal to p_f and have BAU emissions greater than or equal to $\underline{e}_{u0}$ and less than or equal to b. The horizontal dashed line, denoted by α, represents the sequestration limit for each firm. Regions $A_1, A_2,\ldots, A_5$ are embedded in a coordinate system with axes represented by the dash-dotted lines to represent the possibility that some firms may have negative BAU emissions (i.e., some sequester emissions prior to any regulation).

where $\tilde{e}_{u0} = \min\left\{\overline{e}_{u0}, p_f b/c_u\right\}$. The quantities of E_{NA} and E_{UC} are given by

$$E_{NA} = \int_{\underline{c}_u}^{\overline{c}_u} \int_{\underline{e}_{u0}}^{b} (b - e_{u0})\, dY_u\, dZ_u, \tag{9}$$

$$E_{UC} = \int_{\underline{c}_u}^{p_f} \int_{b}^{\tilde{e}_{u0}} (e_{u0} - b)\, dY_u\, dZ_u. \tag{10}$$

The costs of abatement in the uncapped sector, C_u, are given by

$$C_u = \int_{\underline{c}_u}^{p_f} \int_{\underline{e}_{u0}}^{\tilde{e}_{u0}} c_u(e_{u0} - \alpha)\, dY_u\, dZ_u. \tag{11}$$

Welfare

We define welfare as the difference between the benefits and costs of abatement. Abatement benefits are defined by the function $B(\cdot)$ and satisfy $B'(\cdot) > 0$. Let e_{r0} be the pre-intervention level of emissions in the capped sector and A be the grandfathered permits. Then $\overline{q} = e_{r0} - A$ is the reduction target for the capped sector. To calculate total abatement, we need to subtract non-additional offsets, E_{NA}, and add under-credited emissions reductions, E_{UC}. To get the total abatement in the capped sector, q_r, we further subtract additional offset supply from the uncapped sector, q_u. With these specifications, we write welfare W as

$$W = B(\overline{q} - E_{NA} + E_{UC}) - C_r(\overline{q} - E_{NA} + E_{UC} - q_u) - C_u. \tag{12}$$

The first-best solution equalizes marginal benefits and marginal costs of abatement across sectors. Montero (2000) studies a similar problem in the context of phase in emissions trading programs such as Phase 1 of the Acid Rain Program where some sources of emissions could opt in and become regulated.[23] He demonstrates that the first-best solution can be achieved by adjusting the opt-in allocation to the point where all uncapped units opt in and by adjusting the capped unit permit allocation to account for the supply of over-allocated permits. In our model, the first best can be achieved with a similar strategy, where the baseline is set to the point where all uncapped firms opt in and where the permit allocation is adjusted to account for the supply of non-additional offsets. The baseline is set at the upper bound of the uncapped sector BAU emissions distribution ($b = \overline{e}_{u0}$) so that every uncapped firm opts in. The high baseline generates a supply of non-additional offsets, E_{NA}, that reduces aggregate emissions reductions from the program.[24] To account for this quantity, the policy maker

[23] In a related paper, Montero estimates the welfare effects of the opt-in provision of the Acid Rain Program. He finds that a majority of opt in units were over allocated permits, leading to a small increase in the aggregate emissions cap (Montero, 1999).

[24] This baseline choice eliminates any quantity of under-credited emissions reductions so that $E_{UC} = 0$. This is because no uncapped firm has BAU emissions above the assigned baseline.

increases the reduction target $\overline{q}$ from $\overline{q}=q^*$ to $\overline{q}=q^*+E_{NA}$,where q^* would have been the reduction target had all offsets been additional.[25]

Distributional consequences of the first-best solution

The mechanism for achieving the first-best solution outlined above leads to a significant transfer of rents from the capped to the uncapped sector. The larger reduction target for capped firms is analogous to a smaller permit allocation. The value of the permit allocation to capped firms, $V=p_aA$, is reduced by p_aE_{NA} to achieve the first best.

Therefore, one should be concerned that the policy maker may not be able to adjust the permit allocation to capped firms because of distributional constraints.[26] In fact, no policy to date has attempted to implement a program that would account for non-additional offsets by transferring rents across sectors. Instead of adjusting the initial permit allocation to account for non-additional offsets, the policy maker can regulate the market for carbon offsets directly through a variety of alternative instruments. The use of these instruments will not be as efficient as the first-best prescription. In other words, the inability of the policy maker to adjust the permit allocation puts us in a second-best setting.

We define the cost of this distributional constraint as the welfare cost per dollar of avoided transfer, which is given by the formula

$$\frac{\Delta W}{\Delta V}=\frac{W_{FB}-W_{SB}}{V_{SB}-V_{FB}}. \tag{13}$$

The term ΔW is defined as the non-marginal difference in welfare between first-best setting (W_{FB}) and a second-best setting (W_{SB}, when the permit allocation is fixed). The term ΔV is defined as the difference in rents to the capped sector between the first- and second-best settings (V_{FB} and V_{SB}, respectively).

Moving to the second-best setting by restricting the permit allocation may lead to combinations of alternative instruments being chosen to maximize welfare. In the next sections, we provide formulas that decompose the channels of efficiency by three alternative instruments: more stringent baselines, a trade ratio and a limit on the use of offsets. We refer the reader to Appendix A for formal derivations.

The choice of instruments in a second-best setting

The baseline

Consider a marginal reduction of the baseline assigned to uncapped firms. The welfare effects of an incremental adjustment of the baseline are given by

$$\frac{\partial W}{\partial b}=\underbrace{-\left[B'(\cdot)-p_a\right]\frac{\partial E_{NA}}{\partial b}}_{\mathrm{dW}^{NA}}+\underbrace{\left[B'(\cdot)-p_a\right]\frac{\partial E_{UC}}{\partial b}}_{\mathrm{dW}^{UC}}+\underbrace{\int_{\underline{c}_u}^{p_f}\frac{\partial}{\partial b}\int_{\underline{e}_{u0}}^{\tilde{e}_{u0}}(p_a-c_u)(e_{u0}-\alpha)\,dY_u\,dZ_u}_{\mathrm{dW}^{A}}. \tag{14}$$

Eq. (14) comprises three sources of welfare change associated with a marginal reduction of the baseline. First, dW^{NA} is the *non-additional offsets effect*. This is the efficiency change from non-additional offsets.[27] It is equal to the product of the marginal change in non-additional offsets and the wedge between marginal benefits and marginal costs of abatement of capped firms. A lower baseline implies a smaller mass of firms supplying non-additional offsets and a lower quantity of non-additional offsets awarded to uncapped firms. The lower supply of non-additional offsets can be illustrated in Fig. 1. Areas A_4 and A_5 shrink as the baseline is adjusted down. The combined effect is a reduction in the supply of non-additional offsets. This increases capped firm compliance costs as the cap is effectively tightened when there are fewer non-additional offsets supplied. Emissions benefits are higher as a consequence of the tighter cap. These two effects are represented by the wedge between capped firm marginal benefits and marginal costs of abatement.

The second component, dW^{UC}, is the *under-credited emissions reductions effect*. This is the efficiency change from uncapped firms providing under-credited emissions reductions.[28] It is equal to the product of the change in under-credited emissions reductions and the wedge between marginal benefits and marginal costs of abatement of capped firms. A lower baseline may increase or decrease the mass of firms contributing to under-credited emissions reductions. Based on Fig. 1, the top of area A_1 shrinks as the profit indifference line (7) pivots down. Simultaneously, the bottom of area A_1 expands as

[25] This is shown in the appendix. The result that the first-best solution can be achieved in the presence of asymmetric information has been established in previous work (Spulber, 1988; Kwerel, 1977). Similar to the setting described in Montero (2000), the policy maker requires two instruments to achieve the first-best solution, or one instrument per market failure.

[26] Distributional concerns have traditionally played a major role in the design of cap-and-trade programs and more generally in the choice between policy instruments. As an example, distributional concerns are the primary reason that pollution permits are typically grandfathered instead of auctioned. Studies have explored how distributional constraints influence the cost effectiveness of alternative instruments (Bovenberg et al., 2005, 2008) and how grandfathered permits are necessary to keep capped firm profits unchanged (Goulder et al., 2010).

[27] This effect is an efficiency cost if the pre-existing emissions cap is stringent.

[28] This effect is an efficiency benefit if the pre-existing emissions cap is relaxed.

the baseline is pushed down. An increase in under-credited emissions reductions lowers the supply of additional offsets and increases total abatement. A lower supply of additional offsets increases compliance costs as fewer cheap reductions are purchased from the uncapped sector. Emissions benefits are higher as a result of greater abatement. These two effects are represented by the wedge between capped firm marginal benefits and costs of abatement.

The non-additional offsets effect and the under-credited emissions reductions effect influence emissions and the supply of offsets to capped firms, but do not influence the efficiency gain from allowing capped firms to pay uncapped firms to reduce emissions. This efficiency effect is captured in the last term, dW^A, denoted as the *additional offsets effect*. It is equal to the change in the difference between marginal costs of abatement of capped and uncapped firms for the mass of uncapped firms reducing emissions. Reducing the baseline discourages the production of additional offsets as it lowers the compensation to each uncapped firm that opts in.

The trade ratio

Next we consider the impact of imposing an offset trade ratio between offsets and permits, denoted by t. The trade ratio converts one offset into $1/t$ fungible pollution permits. A ratio greater than one implies that a capped firm must hold more than one offset to cover one unit of emissions. A major difference between a more stringent baseline and the trade ratio is that the latter cannot discourage the supply of non-additional offsets because these are defined as the difference between the baseline and BAU emissions. To decompose the welfare effects of a trade ratio, we first explore how it impacts the problem of capped firms. A trade ratio alters the permit constraint (2) of each capped firm to

$$a^i + \frac{f^i}{t} + a_0^i = e_r^i. \tag{15}$$

The first-order conditions of the capped firm problem imply

$$p_f = \frac{p_a}{t}. \tag{16}$$

Unlike the baseline, the trade ratio creates a wedge between the prices of offsets and permits. Holding the permit price constant, a ratio greater than one depresses the offsets price. The resulting welfare effects of adjusting the trade ratio are given by

$$\frac{\partial W}{\partial t} = \underbrace{[B'(\cdot) - p_a]f}_{\mathrm{dW}^D} + \underbrace{[B'(\cdot) - p_a]\frac{\partial E_{UC}}{\partial t}}_{\mathrm{dW}^{UC}} + \underbrace{\frac{\partial p_f}{\partial t}\int_{\underline{e}_{u0}}^{b} \left(p_a - p_f\right)(e_{u0} - \alpha)\, dY_u + \int_{\underline{c}_u}^{p_f} \frac{\partial}{\partial t}\int_{\underline{e}_{u0}}^{\tilde{e}_{u0}} (p_a - c_u)(e_{u0} - \alpha)\, dY_u\, dZ_u}_{\mathrm{dW}^A}. \tag{17}$$

Comparing (17) to (14) reveals three key differences between the trade ratio and the baseline. First, the trade ratio fails to exploit the non-additional offsets effect from the baseline policy. That is, the trade ratio fails to directly discourage the production of non-additional offsets. In place of the non-additional offsets effect is the *discounted offsets effect*, denoted by dW^D.[29] This is the efficiency change of requiring capped firms to hold more than one offset per unit of emissions.[30] Raising the trade ratio above one reduces aggregate emissions as one unit of abatement from the uncapped sector converts to less than one unit of fungible pollution permits in the capped sector.[31] Second, while adjusting the baseline has an ambiguous effect on under-credited emissions reductions, in contrast a larger trade ratio reduces under-credited emissions reductions. As a consequence, fewer under-credited emissions reductions increases overall emissions. This is captured in the second term in Eq. (17), dW^{UC}. Third, the trade ratio discourages the opt-in decision of uncapped firms. This can be seen in the *additional offsets effect*, dW^A. A trade ratio larger than one reduces the offsets price below the permit price, reducing the incentive for uncapped firms to opt in, represented by the first term in dW^A. The second term is similar to the *additional offsets effect* in (14). It is equal to the change in the difference between marginal costs of abatement of capped and uncapped firms for the mass of uncapped firms reducing emissions. Increasing the trade ratio discourages the production of additional offsets as it lowers the offset production revenue to uncapped firms.

The offsets limit

Finally we consider a limit of L on the use of offsets by capped firms. An offsets limit adds a constraint to the capped firm problem:

$$f^i \le L. \tag{18}$$

[29] In the offsets literature, discounting offsets is equivalent to establishing a trade ratio greater than one. A discount factor of $\delta < 1$ converts one offset into δfungible offsets. This implies an identity between an offset discount factor and an offset trade ratio: $\delta = 1/t$. See Kollmuss et al. (2010) for more details.

[30] This effect is an efficiency cost if the pre-existing emissions cap is stringent. This effect, however, can be an efficiency benefit if the pre-existing cap is relaxed.

[31] This holds true whenever there is a positive supply of additional offsets. If all offsets are non-additional, then discounting will have no effect on aggregate emissions.

With this additional constraint, the capped firm first-order conditions imply a relationship between the prices:

$$p_f = p_a - \beta. \tag{19}$$

The term β is the multiplier on the limit constraint. A binding limit ($\beta > 0$) drives a wedge between the permit price and the offsets price.[32] For a fixed permit price, a binding limit reduces the offsets price. The offsets price is reduced until the total supply of offsets equals the limit. Like the trade ratio, this feature of the limit has the effect of reducing the supply of additional offsets while not discouraging the supply of non-additional offsets.[33] This is because the supply of non-additional offsets is independent of the offsets price. The welfare effects of adjusting a binding limit are given by

$$\frac{\partial W}{\partial L} = \underbrace{[B'(\cdot) - p_a]\frac{\partial E_{UC}}{\partial L}}_{dW^{UC}} + \underbrace{\frac{\partial p_f}{\partial L}\int_{\underline{e}_{u0}}^{b}\left(p_a - p_f\right)(e_{u0} - \alpha)\, dY_u + \int_{\underline{c}_u}^{p_f}\frac{\partial}{\partial L}\int_{\underline{e}_{u0}}^{\tilde{e}_{u0}}(p_a - c_u)(e_{u0} - \alpha)\, dY_u\, dZ_u}_{dW^{A}}. \tag{20}$$

A comparison of (20) to (14) reveals that the limit, similar to the trade ratio, does not influence welfare through discouraging the supply of non-additional offsets as the *non-additional offsets effect* is missing. As it is the case with the previous two instruments, however, the limit influences welfare through adjusting the quantity of under-credited emissions reductions, dW^{UC}. The limit discourages uncapped firms from participating, which lowers the quantity of under-credited emissions reductions.

The second welfare effect seen in (20) is denoted by dW^A. A comparison of (20) to (17) demonstrates that the limit and the trade ratio discourage the production of additional offsets through the same two channels. In contrast to the trade ratio, however, establishing a binding limit on offsets raises emissions relative to a policy with a non-binding limit. The under-credited emissions reductions effect is the only component in (20) that has welfare adjustments from emissions changes. A more stringent limit raises emissions because it lowers the quantity of under-credited emissions reductions and does not require capped firms to hold more offsets per unit of emissions.

Summary

In Table 1, we summarize how adjusting the instruments influences emissions and offset supply. We compare how the instruments influence the supply of non-additional offsets, the supply of additional offsets, the supply of under-credited emissions reductions and total emissions. From the welfare formulas, we see that the baseline is the only instrument that reduces the supply of non-additional offsets.[34] The trade ratio can reduce emissions if the discounted offsets effect dominates the under-credited emissions reductions effect. A more stringent offsets limit raises emissions. As the offsets limit depresses the offsets price, the quantity of under-credited emissions reductions falls, increasing total emissions.

In Table 2, we sign the four effects appearing in the welfare formulas. In the first panel, we consider a relaxed pre-existing cap so that marginal abatement benefits exceed marginal abatement costs. In this case, the non-additional offsets effect and the under-credited emissions reduction effect are both positive so that lowering the baseline raises social welfare through these two effects.[35] In the second panel we consider a stringent pre-existing cap so that the marginal abatement benefits are exceeded by marginal abatement costs. In this case, the three welfare effects for adjusting the baseline down are all negative, implying that the baseline should be increased at least until marginal abatement benefits equal marginal abatement costs.[36]

Since the welfare cost per dollar of avoided transfer equation (13) is non-marginal, we cannot assess the magnitude of welfare losses from restricting the use of the emissions cap by comparing the welfare formulas above. Therefore we rely on numerical simulations to rank the instruments along several dimensions, including the composition of offsets, total emissions, and welfare.

The numerical model

We now supplement the analytical model with a numerical model calibrated to represent a United States cap-and-trade program with carbon offsets. The purpose of the numerical model is to quantify exact welfare assessments in contrast with the marginal effects presented above. This is relevant for comparing the efficacy of the three instruments, providing

[32] The Waxman–Markey bill did not provide details on the mechanism to distribute the offsets if the cap is binding. What would have most likely happened would be that each firm under the cap would be given an individual cap, similar to the way the EU-ETS has assigned separate offset limits for each country (Kollmuss et al., 2010). In this case if the individual caps are binding then offsets will sell at a discount relative to permits.

[33] The limit can influence the supply of non-additional offsets in a setting where 100 percent of the offset supply is non-additional. In this unusual case, lowering the limit would be equivalent (in terms of total emissions) to lowering the allocation of permits to capped firms. An optimal limit will then be set to equate the marginal benefits and marginal costs of abatement in the capped sector (since no abatement will be happening in the uncapped sector).

[34] This is true unless the limit or trade ratio are selected so that there is no supply offsets, which would occur if $t=0$ or $L=0$.

[35] Overall welfare may decline, however, if the welfare loss from fewer additional offsets entering the market dominates the two welfare-improving effects.

[36] This scenario is much less likely to occur in the beginning stages of cap-and-trade programs. This is because virtually all proposed and existing programs start with a relaxed cap that becomes more stringent over time.

Table 1
Marginal emissions and offset supply effects of the offsets instruments.

Instrument[a]	Non-additional offsets	Additional offsets	Under-credited emissions reductions	Capped sector emissions[b]	Uncapped sector emissions[c]	Total emissions[d]
Baseline	Decrease	Decrease	Ambiguous	Decrease	Ambiguous	Decrease
Trade ratio	No effect	Decrease	Decrease	Decrease	Increase	Ambiguous
Limit	No effect	Decrease	Decrease	Decrease	Increase	Increase

[a] The marginal effects represent more stringent instrument choices. We consider the marginal effect of reducing the baseline, increasing the trade ratio and reducing the limit.

[b] For the Baseline and Limit, the change in capped sector emissions is equal to the change in additional offset supply plus the change in non-additional offset supply. For the Trade ratio, the change in capped sector emissions equals sum of three components: 1. the change in additional offset supply, 2. the change in non-additional offset supply and 3. the change in emissions as a result of capped firms requiring to hold more than one offset to account for one unit of its own emissions. The third effect can be illustrated with Eq. (15). If the trade ratio t increases and permit purchases and the permit allocation are held fixed, capped firm emissions must fall to meet the compliance constraint (15).

[c] The change in uncapped sector emissions equals the negative of the sum of the change in additional offsets and the change in under-credited emissions reductions. This is because fewer additional offsets supplied or a lower quantity of under-credited emissions reductions imply that there is less abatement happening in the uncapped sector. The change in non-additional offsets has no effect on uncapped sector emissions because these offsets do not correspond to abatement.

[d] Total emissions are the sum of capped and uncapped sector emissions. Therefore, the total emissions effect for each instrument is the sum of the sector-wide emissions effects. For example, as the trade ratio decreases capped sector emissions and increases uncapped sector emissions, we denote the effect of higher trade ratio on total emissions as Ambiguous.

Table 2
Marginal welfare effects of the offsets instruments.

Instrument	Non-additional offsets effect	Additional offsets effect	Under-credited emissions reductions effect	Discounted offsets effect
(a) Relaxed pre-existing cap ($B'(\cdot) > p_a$)				
Baseline	Positive	Negative	Positive	Non-existent
Trade ratio	Non-existent	Negative	Ambiguous	Positive
Limit	Non-existent	Negative	Negative	Non-existent
(b) Stringent pre-existing cap ($B'(\cdot) < p_a$)				
Baseline	Negative	Negative	Negative	Non-existent
Trade ratio	Non-existent	Negative	Ambiguous	Negative
Limit	Non-existent	Negative	Positive	Non-existent

magnitudes of the trade-offs between efficiency and rent transfers and evaluating optimal instrument choices under the second-best setting. We now provide a brief description of the model calibration procedure. A complete description of the model is in Appendix B.

Model calibration

The purpose of the numerical model is to yield generic insights that are applicable to a range of climate mitigation programs. Even though our objective is to quantify general relationships, we choose a specific set of parameter values to calibrate the model. Our central values represent abatement costs and benefits from a federal cap-and-trade program in the United States. In particular, we calibrate the analytical model with short-run (2015–2020) estimates of emission reduction costs, BAU emissions and marginal benefits of abatement obtained from the literature.[37] We use short-run estimates for two reasons. First, short-run forecasts are less likely to suffer from forecasting error. Second, the problem of non-additionality is most pronounced in the short run because the price of offsets is expected to be lowest in the short run.[38] To illustrate how alternative assumptions on costs and benefits may effect efficient policy decisions, we consider significant departures from these central case values in the sensitivity analysis.

The capped sector represents industries likely to be covered under a federal greenhouse gas (GHG) cap-and-trade program. We base our representation on the industries that would have been covered under the H.R. 2454 American Clean Energy and Security Act, henceforth the Waxman–Markey bill, which include coal-fired power plants, petroleum refineries, natural gas refineries, iron and steel production and cement manufacture. The capped sector is regulated by a cap-and-trade program. We model the capped sector as a representative firm that takes equilibrium prices as given. This is a standard assumption used to evaluate compliance costs of cap-and-trade programs (Fell and Morgenstern, 2010). The capped sector is allocated a fixed quantity of emissions permits that are equal to capped sector BAU emissions minus a reduction target. The

[37] Alternatively we can calibrate the model with medium- or long-run estimates to quantify the effects of the model for a longer time span. We leave this exercise for future work that incorporates dynamics.

[38] What we mean by the problem of non-additionality is the ratio of non-additional to additional offsets. When the price of offsets is low, the supply of additional offsets is low, making the ratio of non-additional to additional offsets large.

Table 3
Benchmark data.

Description	Value	Source
Capped sector BAU emissions[a]	5071	EPA Data Annex (2009)
Uncapped sector BAU emissions	365	EPA MAC Curves (2009)
Capped sector abatement	864	EPA Data Annex (2010)
Uncapped sector abatement	486	EPA MAC Curves (2009)
Uncapped sector sequestration potential	1027	EPA MAC Curves (2009)
Percent of offsets that are non-additional[b]	40	Schneider (2009)
Social cost of carbon[c]	25	EPA Technical Support Document (2010)

[a] Emissions are reported in million metric tons of CO_2 equivalent.
[b] Equal to the quantity of non-additional offsets divided by total offset supply at a baseline equal to the expected value of uncapped firm BAU emissions.
[c] Represents an estimate for the year 2016 and is reported in (year 2000) dollars per ton of CO_2 equivalent.

uncapped sector represents major sources of mitigation that will likely not be capped in a federal climate policy. These sources include forestry and agriculture.

Data

We use estimates from the Environmental Protection Agency (EPA) analysis of Waxman–Markey of BAU emissions for the capped and uncapped sectors (EPA, 2009a). Capped sector marginal costs of abatement are calibrated to match extrapolated values from the EPA's simulation of the Intertemporal General Equilibrium Model (IGEM) for the year 2016, while uncapped sector marginal costs of abatement are calibrated based on the EPA Updated Forestry and Agriculture marginal abatement cost curves (EPA, 2009b).

Parameters

The distributions of BAU emissions and marginal costs of abatement are assumed to be uniform. We calibrate the heterogeneity of BAU emissions in the uncapped sector so that the percentage of offsets that are non-additional at a carbon price of 25 dollars is 40 percent. This value approximately matches evidence from the largest carbon offsets program in the world, the Clean Development Mechanism. The marginal benefits of abatement, known as the Social Cost of Carbon (SCC), is set at 25 dollars per ton of CO_2 equivalent, representing estimated damages between 2015 and 2020 (EPA, 2010). Table 3 summarizes the values used to calibrate the model and Table 4 shows implied parameter values. Monetary values are reported in year 2000 dollars. The calibrated model approximately matches the predicted compliance cost savings from including offsets in the Waxman–Markey cap-and-trade program. Appendix B provides more details on the calibration procedure and data used to identify the parameters of the model.

Numerical results

This section presents results from the numerical model. To compare the offsets instruments, we calculate the welfare effect of imposing an emissions cap under different assumptions on the set of instruments available to the policy maker. We emphasize the welfare effects relative to a series of benchmark settings that we consider in the next section.

To facilitate comparisons, we simulate the model without offsets as a benchmark. Our emphasis is on qualitative, rather than quantitative, differences across policies. The quantitative differences can vary depending on our assumptions for marginal abatement costs and benefits and the heterogeneity in uncapped firm BAU emissions. Note that our analysis abstracts from other sources of emissions changes that may plague offsets markets, including leakage and permanence.[39]

Benchmark simulations

We first examine benchmark simulations that help facilitate comparisons of the three offsets instruments. Table 5 presents simulation results for our benchmark settings. The first setting represents a cap-and-trade program that does not

[39] While leakage and permanence may have relevant impacts on the welfare effects of offsets programs, we do not focus on them in our paper. Previous literature suggests that liability and insurance or buffering programs are superior instruments for handling leakage and permanence (Murray et al., 2007).

Table 4
Implied parameter values.

Parameter description	Parameter	Value
Capped sector lower bound of marginal costs[a]	$\underline{c}_r$	0
Uncapped sector lower bound of marginal costs	$\underline{c}_u$	0
Capped sector upper bound of marginal costs	$\overline{c}_r$	147
Uncapped sector upper bound of marginal costs	$\overline{c}_u$	72
Capped sector average BAU emissions[b]	$\mathbb{E}(e_{r0})$	5071
Uncapped sector average BAU emissions	$\mathbb{E}(e_{u0})$	365
Capped sector lower bound of BAU emissions	$\underline{e}_{r0}$	5071
Uncapped sector lower bound of BAU emissions	$\underline{e}_{u0}$	−563
Capped firms upper bound of BAU emissions	$\overline{e}_{r0}$	5071
Uncapped sector upper bound of BAU emissions	$\overline{e}_{u0}$	1293

[a] Marginal costs are reported as (year 2000) dollars per ton of CO_2 equivalent.
[b] Emissions are reported as million metric tons of CO_2 equivalent.

Table 5
Welfare and rents under benchmark settings.

Description	No offsets	Full information[a]		Imperfect information[b]	
Permits Baselines	*Optimal* –	*No offsets setting* *Firm-specific*	*Optimal* *Firm-specific*	*No offsets setting* *Mean*	*Optimal* *Optimal*
Welfare[c]	10,800	+36%	+56%	+15%	+56%
Costs	10,800	−36%	+56%	−62%	+56%
Benefits	21,600	0%	+56%	−23%	+56%
Cost per ton of emissions reductions[d]	12.5	8.0	12.5	6.2	12.5
Capped sector rents[e]	105,170	67,310	93,024	54,827	69,815

[a] Defined by the policy maker observing uncapped firm-specific BAU emissions. Under this setting, baselines are set equal to BAU emissions so that the supply of non-additional offsets and the quantity of under-credited emissions reductions equals zero.
[b] Defined by the policy maker observing the distribution of uncapped firm BAU emissions. Under this setting, a common baseline is set for all uncapped firms.
[c] Reported in millions of dollars in the No offsets setting. Values in the Full information and Imperfect information settings are reported relative to the No offsets setting.
[d] Measured in dollars per ton of CO_2 equivalent.
[e] Reported in millions of dollars and defined as the product of the capped sector permit allocation and the equilibrium permit price.

include offsets. Under this setting, the allocation of permits is endogenously chosen to maximize welfare. Welfare, which is defined as emission reduction benefits minus costs, is 10.8 billion dollars.[40]

Next we simulate the model assuming that the policy maker has full information on BAU emissions. Under this assumption, the policy maker assigns baselines equal to BAU emissions of uncapped firms, $b^i = e^i_{u0}$. In these simulations, adverse selection is not present and only additional offsets are awarded to the uncapped sector and supplied to capped firms. When the allocation of permits remains at the no offsets optimum, including offsets increases welfare by 36 percent. The welfare change is attributed to a reduction in compliance costs, as cheaper reductions from the uncapped sector replace more expensive reductions in the capped sector. When the cap is re-optimized when offsets are included, the welfare change increases to 56 percent. This increase represents the first-best allocation of emission reductions.

The next set of simulations assumes that the policy maker has imperfect information on BAU emissions. These settings represent the numerical version of our analytical model. With imperfect information, the policy maker assigns a single baseline to each uncapped firm. We consider two benchmark cases with imperfect information. First, we consider the case where the allocation of permits is equal to the no offsets optimum and the baseline equals the expected value of BAU emissions. This setting achieves a 15 percent increase in welfare relative to the no offsets program, a value which is significantly lower than the full information settings. This is because firms in areas A_4 and A_5 are supplying non-additional offsets, which increases aggregate emissions and lowers the benefits from the program. Second, we consider the case where the policy maker can select both the allocation of permits and the baseline. With both instruments, the policy maker can achieve the first-best outcome. The increase in welfare of 56 percent matches the welfare change in the full information setting that allows the policy maker to re-optimize the permit allocation. Comparing capped sector rents across the settings, however, demonstrates the distributional consequence of the imperfect information first-best outcome. Capped sector rents in the imperfect information first-best outcome are 69.8 billion dollars compared to 105.2 billion dollars in the no offsets

[40] The implied emissions price from the case without offsets is equal to the social cost of carbon.

Table 6
Instrument choice.

Description	No offsets	First best	Second best[a]			
			Unrestricted	Baseline	Ratio	Limit
Permits	*Optimal*	*Optimal*	*No offsets setting*	*No offsets setting*	*No offsets setting*	*No offsets setting*
Value[b]	4207	2793	4207	4207	4207	4207
Baseline	–	*Optimal*	*Optimal*	*Optimal*	*Mean*	*Mean*
Value[b]	–	1293	−447	−229	365	365
Trade ratio	–	*Optimal*	*Optimal*	*Restricted Optimal*[c]	*Optimal*	1:1 *ratio*
Value	–	1	0.67	1	1.78	1
Limit	–	*Optimal*	*Optimal*	*Optimal*	*Optimal*	*Optimal*
Value	–	Non-binding	Non-binding	Non-binding	Non-binding	Non-binding

[a] Defined as fixing the permit allocation equal to 4207 $MMTCO_2e$.
[b] Measured in million metric tons of CO_2 equivalent.
[c] The restricted optimal setting is defined by the policy maker selecting the baseline, trade ratio and limit subject to the constraint $t \geq 1$.

case. While the first-best solution achieves a significant increase in welfare, along with it comes a rent transfer equal to roughly 30 percent of rents under the no offsets setting.

Instrument choice

In the analytical model, we consider one instrument at a time to isolate key welfare effects. In the numerical model we consider the welfare implications of allowing the policy maker to choose the instruments simultaneously. This allows us to determine whether some instruments may be coupled together to achieve higher welfare gains relative to cases when instruments are optimized one by one. Moreover, we determine whether some instruments welfare-dominate others by restricting them one at a time.

Table 6 shows optimal instrument choices under different assumptions on the policy maker instrument choice set. Without offsets, the optimal allocation of permits is 4207 $MMTCO_2e$. The remaining settings include offsets in the case when the policy maker has imperfect information on BAU emissions. To achieve the first best under imperfect information, the baseline is set equal to the upper bound of BAU emissions ($b = \overline{e}_{u0}$) and the permit allocation is adjusted down to account for the supply of non-additional offsets. The trade ratio and the limit are not utilized to achieve the first best.

Next we simulate the model under four second-best settings that are characterized by an exogenous permit allocation set equal to the no offsets optimum. First, we simulate the model when the baseline, trade ratio and limit are selected simultaneously by the policy maker. We label this scenario as Unrestricted. Importantly – and surprisingly – the policy maker finds it optimal to couple a trade ratio less than one with a low baseline. This finding is robust to different parameter assumptions, as confirmed in the sensitivity analysis below.[41] From the first-order condition of the capped firm problem, a trade ratio less than one has the effect of increasing the offsets price. A higher offsets price encourages a larger supply of additional offsets and a larger quantity of under-credited emissions reductions. The policy maker simultaneously adjusts the baseline down to reduce the supply of non-additional offsets. This increases welfare through the non-additional offsets effect as greater abatement is achieved. Adjusting the baseline down, however, reduces the welfare gains from the additional offsets effect as fewer uncapped firms find it profitable to opt in. A trade ratio less than one counteracts this effect by boosting up the offsets price. This leads to a welfare gain that is represented by the additional offsets effect in Eq. (17).

In practice, however, it is unlikely for a policy to adopt a trade ratio less than one.[42] In addition to the effects described above, a trade ratio less than one allows capped firms to turn one offset into more than one fungible pollution permit. If not coupled with another instrument that lowers emissions, this has the effect of raising aggregate emissions.[43] For this reason, we consider a setting that allows the policy maker to select the three instruments simultaneously with the constraint that the trade ratio cannot be below one, $t \geq 1$. We label this policy as Baseline since we find that in this setting, only the baseline is utilized. The optimal baseline in this setting is equal to −229 $MMTCO_2e$, a value that is larger (i.e. more generous) than the one from the previous setting. This is because the policy maker can no longer encourage the production of additional offsets by selecting a trade ratio less than one. The optimal trade ratio of one implies that it is not used as a method of reducing emissions. A ratio larger than one can reduce emissions but it also reduces the incentive for uncapped firms to opt in and it distorts the decision for uncapped firms to reduce emissions. While adjusting the baseline down also discourages uncapped firms from opting in, it does not distort the decision for uncapped firms to reduce emissions as it does not directly

[41] This is shown in the sensitivity analysis Table 12 in the column labeled Unrestricted.

[42] We are not aware of an offsets program that uses a trade ratio less than one. A recent survey of environmental offsets programs finds that there do not exist programs assigning a trade ratio less than one (Hahn and Richards, 2010).

[43] For example, the policy maker could lower the permit allocation to capped firms or create under-credited emissions reductions with a lower baseline.

Table 7
Composition of offsets and emissions.

Outcome	No offsets	First best	Second best			
			Unrestricted	Baseline	Ratio	Limit
Capped sector abatement[a]	864	864	684	699	650	450
Uncapped sector abatement	0	486	237	217	171	211
Under-credited emissions reductions	0	0	120	81	24	30
Additional offsets	0	486	117	136	162	181
Non-additional offsets	0	928	4	29	233	233
Offset supply	0	1414	121	165	395	414
Capped sector emissions	4207	4207	4388	4372	4421	4621
Uncapped sector emissions	365	−121	128	148	193	154
Total emissions[b]	4572	4086	4515	4520	4614	4775

[a] Abatement, offsets and emissions quantities are measured in million metric tons of CO_2 equivalent.
[b] Total emissions are defined as the sum of capped and uncapped sector emissions.

reduce the offsets price. This difference is represented by the term in the additional offsets effect appearing in Eq. (17) that is absent in Eq. (14).

To compare the efficacy of the trade ratio and the limit, we remove the baseline from the policy maker's choice set and assume that it is set to equal the expected value of uncapped firm BAU emissions. In this setting, the second-best trade ratio equals 1.78, requiring capped firms to buy 1.78 offsets to account for one unit of emissions. The limit remains non-binding in this case, demonstrating that on welfare grounds, the trade ratio is a superior instrument. This is because the trade ratio and limit both discourage under-credited emissions reductions and the supply of additional offsets through a reduced offsets price. But the trade ratio can reduce emissions while the limit cannot. In fact, there is no analog to the discounted offsets effect in the limit welfare formula.

To determine whether the limit is binding under any circumstances, we restrict the baseline and the trade ratio to be fixed and allow the policy maker to select a limit that maximizes welfare. The limit does not bind in this case. This suggests that the limit cannot improve welfare in the presence of adverse selection.[44]

Composition of offsets and emissions

Table 7 compares the quantity of additional and non-additional offsets and the sources of abatement for each of the simulation settings. In the first-best outcome, the supply of non-additional offsets is significant. Out of the total offset supply of 1414 $MMTCO_2e$, 928 $MMTCO_2e$ are non-additional. These offsets come from the first-best instrument choice of the baseline set high enough to encourage all uncapped firms to opt in. At this baseline choice, every uncapped firm earns some non-additional offsets since BAU emissions are below each firm's baseline.

In the Unrestricted policy, non-additional offsets are close to zero. This is because the non-additional offsets effect dominates the additional offsets effect at the second-best optimal policy. The efficient baseline choice is so low in this setting that very few non-additional offsets are awarded to uncapped firms. Surprisingly, total emissions are lower in the Unrestricted setting relative to setting when offsets are not allowed. This is because the quantity of under-credited emissions reductions equal to 120 $MMTCO_2e$ has the effect of lowering aggregate emissions. This effect dominates the increase in emissions from the supply of non-additional offsets and from a trade ratio less than one.

Under the Baseline policy, additional and non-additional offset supplies are both higher than they appear in the Unrestricted policy. The Baseline policy sets a higher baseline to uncapped firms to encourage the supply of additional offsets. This also raises the supply of non-additional offsets from 4 $MMTCO_2e$ to 29 $MMTCO_2e$. Under-credited emissions reductions fall to 81 $MMTCO_2e$ because the price of offsets is not boosted up by a trade ratio less than one.

The Ratio and Limit policies show a substantially larger supply of non-additional offsets of 233 $MMTCO_2e$. This is because neither of these instruments are capable of reducing the supply of non-additional offsets. As a consequence, we see a much larger supply of offsets and higher aggregate emissions.

[44] The result that the optimal policy suggests a non-binding limit begs the question of why offset limits exist at all. Some programs that have limits explicitly state in its design summary that offsets are supposed to be "supplemental" to emission reductions taking place among capped firms (Kollmuss et al., 2010). This preference for supplementary reductions may stem from three reasons. First, it may be that policy makers are worried that not all offsets are additional, so that a limit restricts the potential increase in emissions. Second, it may be an ethical concern. Constituents may feel that polluters should not be able to depend on other uncapped firms to reduce emissions for them. Third, uncertain abatement costs with increasing cap stringency over time with unlimited offset quantities may keep permit prices below levels sufficient to induce investment in low-emission technologies or curb demand for high emission products (Fell et al., 2012; De Cain and Tavoni, 2012). We thank a referee for pointing out this third possibility.

Table 8
Second-best welfare.

Outcome	No offsets	Second best			
		Unrestricted (%)	Baseline (%)	Ratio (%)	Limit (%)
Welfare[a]	10,800	+35	+34	+26	+15
Costs	10,800	−21	−22	−36	−62
Benefits	21,600	+7	+6	−5	−23

[a] Reported in millions of dollars in the No offsets setting. Values in the Second Best settings are reported relative to the No offsets setting.

Second-best welfare

We now consider the welfare impacts – abatement benefits less economic costs – of the different policies. Table 8 presents the welfare impacts of the four second-best policies relative to a program that does not include offsets. The Unrestricted policy achieves the greatest welfare gain that is 35 percent greater than the welfare impact of a program without offsets. We see that under this policy that abatement benefits are 7 percent greater than the no offsets policy. This is because under-credited emissions reductions exceed the supply of non-additional offsets and the extra emissions from a trade ratio less than one (see Table 7).

The same effect holds true for the Baseline policy which achieves an increase in benefits of 6 percent. The Baseline policy increases welfare by 34 percent, a value that is slightly less than the Unrestricted policy. This implies that restricting the trade ratio to be equal to or greater than one does not sacrifice much welfare. The additional efficiency gains from encouraging greater participation of uncapped firms through a higher offsets price just barely exceeds the welfare losses from higher emissions.

The Ratio and Limit policies achieve an increase in welfare that is smaller than the efficiency gains from the Unrestricted and Baseline policies. This result is driven by the absence of the non-additional offsets effect in the trade ratio and limit formulas. Since neither instrument can discourage the supply of non-additional offsets, benefits dramatically fall under these settings by 5 percent and 23 percent, respectively. The Ratio policy achieves a higher welfare gain compared to the Limit policy because of the discounted offsets effect. This effect increases benefits by effectively lowering emissions via requiring capped firms to hold more than one offset to cover one unit of emissions. Even though the trade ratio discourages the supply of additional offsets and achieves a smaller cost reduction of 36 percent, the discounted offsets effect more than compensates for this as the welfare gain under the Ratio policy is 11 percentage points higher than the welfare gain under the Limit policy.

Distributional concerns

We now examine the distributional consequences of the policies in Table 9. Moving from a program that does not include offsets to the first-best outcome, we see a large reduction in capped sector rents from 105, 170 million dollars to 69, 815 million dollars. Under most of the second-best settings, however, the reduction in rents is smaller.

To evaluate the distributional formula (13), we calculate two terms: First, we require the difference between the first-best welfare and the welfare from the particular policy. We denote this value in Table 9 as Welfare change. The welfare change is the largest when offsets are not included in the program (6075 million dollars) since all of the cheaper reductions from uncapped firms are not realized. The Unrestricted and Baseline policies achieve the lowest welfare loss of 2331 and 2421 million dollars, respectively. This is because these policies are able to encourage uncapped firms to opt in and reduce emissions. Second, we compute the avoided transfer of rents, which is defined as the quantity of capped sector rents in a particular policy minus the capped sector rents under the first-best solution. The avoided transfer is the largest under the no offsets setting (35, 335 million dollars). The avoided transfers are lower under the second-best settings because the permit price is depressed from the existence of offsets.

The Baseline policy achieves a welfare cost per unit of avoided transfer of 0.16. This value is lower than the marginal excess burden of a labor tax of 0.40 dollars (Gruber, 2010). If the policy maker had to choose among the policy options of sacrificing 0.16 dollars in welfare to avoid one dollar of transfers or allowing the rent transfer to take place but compensate capped firms through revenues generated from a labor tax, they should choose the former as it is less costly per dollar of transfers.

The welfare cost per unit of avoided transfer is substantially lower than the marginal excess burden. This follows from the fact that the rent transfer is significantly larger than the welfare gain stemming from the first-best mechanism. This result can be explained by illustrating the first-best mechanism using Fig. 1. The first best requires moving the baseline b up to $b = \overline{e}_{u0}$ so that all uncapped firms opt in. There are two sources of rent transfer from this action. First, uncapped firms that would have opted in without the first best implemented now are awarded a significantly larger quantity of non-additional offsets that they sell to the capped sector. These firms are represented by areas A_3, A_4 and A_5. Second, firms that would not

Table 9
Distributional effects.

Outcome	No offsets	First best	Second best			
			Unrestricted	Baseline	Ratio	Limit
Capped sector rents[a]	105,170	69,815	83,334	85,046	79,183	54,827
Permit price[b]	25.00	25.00	19.81	20.22	18.82	13.03
Welfare change[c]	6075	–	2331	2421	3227	4455
Avoided transfer[d]	35,335	–	13,519	15,231	9368	−14,988
Welfare cost per unit of avoided transfer[e]	0.17	–	0.17	0.16	0.34	−0.30

[a] Reported in millions of dollars.
[b] Reported in dollars.
[c] Defined by subtracting the welfare in the current setting from the welfare in the First best setting. Reported in millions of dollars.
[d] Defined by subtracting the capped sector rents in the First-Best setting from the current setting. Reported in millions of dollars.
[e] Defined as the ratio of the welfare change and the avoided transfer.

have opted in without the first-best mechanism now opt in and sell non-additional offsets. These firms are represented by areas A_1 and A_2. Therefore, every eligible firm sells a significant quantity of non-additional offsets under the first-best outcome. The rent transfer occurs to counteract the emissions consequences of these offsets as the policy maker reduces the allocation of permits by an amount that is equal to the new quantity of non-additional offsets.

The welfare gain from the first-best mechanism comes from encouraging uncapped firms that can cheaply reduce emissions that otherwise would not have opted in. These firms appear in area A_1. The welfare gain from the first-best mechanism will be a function of the cost-effectiveness of these firms relative to the most expensive abatement occurring in the capped sector. This welfare gain is likely to be substantially less than the rent transfer associated with implementing the first best because of two reasons. First, most firms that have cheap mitigation costs would already opt in without the first best implemented.[45] Second, the size of A_1 is most likely a small fraction of the universe of eligible uncapped firms. Since this result may depend on policy design parameters that we use in our central case, in the next section we investigate various alternative assumptions to test its sensitivity.

Further analysis

Alternative baselines

Thus far we have focused on a setting where a policy maker has access to all three offsets instruments. In some emissions trading programs, however, it may be the case that baselines are set independently from the choice of the trade ratio or the limit. This feature motivated our consideration of treating the baseline as exogenous to the policy maker under the Ratio and Limit policies. Under these policies, however, we considered a baseline set to equal the expected value of BAU emissions. Some baseline protocols could, in practice, call for higher or lower baselines, depending on the stringency of the offset standard. To consider how different baselines influence outcomes for welfare and rent transfers, we simulate the model assuming alternative baselines. In particular, we set the baseline equal to 50 percent and 200 percent of the expected value of BAU emissions. The results appear in Table 10. The Low baseline and High baseline settings are simulated with a baseline set to equal 50 percent and 200 percent of the expected value of BAU emissions, respectively. For the Low baseline case, the optimal trade ratio is now only 1.45. The policy maker does not need to set a stringent trade ratio in this case because the baseline has already been set low. The same intuition applies to the High baseline case. Here we see a higher trade ratio of 2.69 to account for a large supply of non-additional offsets.

In contrast to our results above, we find that it is optimal to place a limit of zero in the High baseline case. For a high baseline, the efficiency losses from higher emissions dominate the efficiency gains from including offsets in the program.[46] Therefore the optimal limit of zero is equivalent to not allowing offsets in the program. As long as marginal benefits from abatement exceed marginal costs, the optimal policy is to set the offsets limit to zero.[47]

[45] Firms that would already opt in are located in areas A_3 and A_4.

[46] The reverse holds true if the exogenous cap is very stringent. This is because under a stringent cap (i.e. when $B'() < p_a$) allowing extra non-additional offsets in the program improves welfare (see Table 2).

[47] Our model does not include other market failures besides the emissions externality and the information asymmetry. When additional failures exist, such as the adoption of new technology, binding limits may be optimal as shown in De Cain and Tavoni (2012).

Table 10
Alternative baselines.

Description	Low baseline ($b=0.5\mathbb{E}(e_{0u})$)		High baseline ($b=2\mathbb{E}(e_{0u})$)	
Ratio	*Optimal*	1:1 *ratio*	*Optimal*	1:1 *ratio*
Value	1.45	1	2.69	1
Limit	*Optimal*	*Optimal*	*Optimal*	*Optimal*
Value	Non-binding	Non-binding	Non-binding	0
Offset supply[a]	304	331	571	0
Additional offsets	155	182	121	0
Non-additional offsets	149	149	450	0
Under-credited emissions reductions	38	45	7	0
Welfare[b]	13,980	13,491	12,920	10,800
Costs	7209	5494	6565	10,800
Benefits	21,189	18,985	19,485	21,600
Capped sector rents	79,705	64,721	79,307	105,170

[a] Offset supplies and emission reductions are reported in million metric tons of CO_2 equivalent.
[b] Welfare, costs, benefits and rents are reported in millions of dollars.

Transaction costs

Several studies have documented that transaction costs associated with the production of carbon offsets can be non-trivial (Antinori and Sathaye, 2007; Galik et al., 2012). We evaluate the impact of transaction costs on the efficacy of the instruments considered by adding a 5 dollar per ton of offsets produced.[48] We assign transaction costs to uncapped firms in line with an analysis of Waxman–Markey by the Congressional Budget Office (Kile, 2009). This value lies within a range of transaction costs estimated in previous work.[49]

We simulate the model with a 5 dollar per ton transaction cost and calculate the optimal set of instruments. Our results appear in Table 11. Two results emerge from the simulations. First, transaction costs do not play a role in determining the relative efficacy of the three instruments. This result is illustrated by comparing Table 6 to the top panel of Table 11. For example, under the Baseline policy, it is always optimal to set a stringent baseline but keep the trade ratio equal to one. Second, the existence of transaction costs dramatically reduces the welfare cost per unit of avoided transfer across all of the policies, which is reported in the last row of Table 11. For the Unrestricted and Baseline policies, the cost is less than five cents per dollar of avoided transfer. The reason that these values are significantly smaller than those we find in a model without transaction costs stems from the fact that a transaction cost essentially shifts the offsets price line in Fig. 1 to the left, which reduces the area A_1. This is the mass of uncapped firms that bring efficiency gains from the first-best mechanism. Since the efficiency gains will be less with higher transaction costs, the sacrifice in welfare when moving to the second-best policies will be lower.

Further sensitivity analysis

Table 12 summarizes the sensitivity of the numerical results to a range of values for relevant parameters. We vary the social cost of carbon, the upper bound of the marginal cost of abatement distributions for the capped and uncapped sectors and the benchmark percentage of offsets that are non-additional.[50] Table 12 displays for different parameter values the optimal instrument choices and the welfare cost per unit of avoided transfer ($\Delta W/\Delta V$).

Two features of the model explain the relationship between the SCC and optimal instrument choice. First, the higher the SCC, the lower the quantity of allowances allocated to capped firms.[51] Second, the optimal quantity of allowances and the

[48] Denoting the per unit transaction cost by t, the profit function of an uncapped firm becomes

$$\pi^i = \max_{\alpha \le e_u^i \le e_{u0}^i} \left\{ (p_f - t)(b - e_u^i) - c_u^i(e_{u0}^i - e_u^i) \right\}. \tag{21}$$

[49] For example, Antinori and Sathaye (2007) compute transaction costs for 26 carbon offset projects around the world. Their survey includes a variety of offset project types, including forestry, energy efficiency, fuel switching, fuel capture, and renewables. These projects operated between 1991 and 2005 and were verified and monitored through different offset protocols, including the CDM, the Chicago Climate Exchange and Climate Trust. The authors find that per dollar per ton of CO_2 transaction costs for the surveyed projects fall within the range of 0.03 per ton of CO_2 and 4.05 per ton of CO_2 with an average of 0.36 per ton of CO_2. Galik et al. (2012) estimate transaction costs for US-based forest carbon offset projects. The authors used a detailed spreadsheet model that includes disaggregated forest types and 10 different regions. For all project types, transaction costs are estimated to be less than 25 percent of median implementation costs, which the authors define as the sum of production costs and transaction costs. We follow the CBO's approach by assigning a 5 dollar per ton of CO_2 to all projects as this value represents a central value to those reported in existing studies.

[50] Adjusting down the upper bound of the marginal cost distribution for uncapped firms represents allowing more offset types into the program, which could potentially include international offsets.

[51] This is because we set the exogenous quantity of allowances to the point that equalizes marginal abatement benefits and marginal abatement costs without offsets.

Table 11
Transaction costs.[a]

Description	First best	Second best			
		Unrestricted	Baseline	Ratio	Limit
Baseline	*Optimal*	*Optimal*	*Optimal*	*Mean*	*Mean*
Value	1293	−563	−351	365	365
Ratio	*Optimal*	*Optimal*	*Restricted Optimal*	*Optimal*	1:1 *ratio*
Value	1	0.50	1	1.68	1
Limit	*Optimal*	*Optimal*	*Optimal*	*Optimal*	*Optimal*
Value	Non-binding	Non-binding	Non-binding	Non-binding	Non-binding
Offset supply[b]	1352	91	100	323	365
Additional offsets	424	91	88	90	132
Non-additional offsets	928	0	12	233	233
Under-credited emissions reductions	0	135	7	15	22
Transaction costs[c]	6761	453	501	1617	1820
Welfare	14,179	13,926	13,364	12,621	12,094
Costs[d]	14,848	8461	9693	6829	4242
Benefits	30,241	22,827	23,058	19,449	16,336
Capped sector rents	69,815	84,540	92,969	81,780	60,870
$\Delta W/\Delta V$	–	0.02	0.04	0.13	−0.23

[a] The simulations presented in this table include a per ton of CO_2 offset transaction cost of 5 dollars.
[b] Offset supplies and emission reductions are reported in million metric tons of CO_2 equivalent.
[c] Transaction costs, welfare, costs, benefits and rents are reported in millions of dollars.
[d] Costs are equal to mitigation costs plus transaction costs.

Table 12
Further sensitivity analysis.

Parameter			No offsets	First best	Second best			
					Unrestricted	Baseline	Ratio	Limit
Social cost of Carbon	40	Permits[a]	3689	1984	3689	3689	3689	3689
		Baseline	–	1293	−295	−162	365	365
		Trade ratio	–	1	0.82	1	1.52	1
		$\Delta W/\Delta V$	0.23	–	0.16	0.16	0.22	1.07
	10	Permits	4725	3362	4725	4725	4725	4725
		Baseline	–	1293	−563	−345	365	365
		Trade ratio	–	1	0.54	1	3.28	1
		$\Delta W/\Delta V$	0.09	–	0.23	0.12	0.55	−0.07
Capped sector upper bound of marginal costs	172	Permits	4334	2920	4334	4334	4334	4334
		Baseline	–	1293	−484	−263	365	365
		Trade ratio	–	1	0.65	1	1.92	1
		$\Delta W/\Delta V$	0.17	–	0.22	0.19	0.47	−0.22
	122	Permits	4032	2695	4032	4032	4032	4032
		Baseline	–	1293	−403	−190	365	365
		Trade ratio	–	1	0.69	1	1.64	1
		$\Delta W/\Delta V$	0.18	–	0.16	0.15	0.30	−0.45
Uncapped sector upper bound of marginal costs	97	Permits	4207	3112	4207	4207	4207	4207
		Baseline	–	1101	−371	−152	365	365
		Trade ratio	–	1	0.68	1	1.63	1
		$\Delta W/\Delta V$	0.16	–	0.17	0.14	0.54	-0.19
	47	Permits	4207	2222	4207	4207	4207	4207
		Baseline	–	1620	−465	−327	365	365
		Trade Ratio	–	1	0.77	1	2.01	1
		$\Delta W/\Delta V$	0.19	–	0.21	0.19	0.28	−0.67
Benchmark percentage of non-additional offsets	60%	Permits	4207	2123	4207	4207	4207	4207
		Baseline	–	1959	−583	−386	365	365
		Trade ratio	–	1	0.65	1	2.35	1
		$\Delta W/\Delta V$	0.12	–	0.12	0.12	0.16	−0.69
	20%	Permits	4207	3302	4207	4207	4207	4207
		Baseline	–	784	−294	−154	365	365
		Trade ratio	–	1	0.8	1	1.63	1
		$\Delta W/\Delta V$	0.21	–	0.33	0.26	0.66	−0.21

[a] Permits and baselines are reported in million metric tons of CO_2 equivalent.

stringency of offsets instruments move in opposite directions.[52] The lower the quantity of allowances, the more lenient the optimal offset policy becomes.[53] This will generally be the case in the second-best settings as well. When the quantity of allowances is low, emissions are low and permit and offset prices are high. Therefore the policy may be achieving too much abatement. In response the policy maker can relax the stringency on offset projects by raising baselines or removing the non-unitary trade ratio. When the social cost of carbon is low (SCC=10), the optimal permit allocation without offsets is high ($A=4725$). Under the Baseline policy, the baseline is set to -365. When the social cost of carbon is high (SCC=40), the optimal cap without offsets is low ($A=3689$). In the Baseline policy, the baseline is set to -162, which is much more lenient than the case when the cap is high.

When the SCC is high, the welfare cost per unit of avoided transfer lies below 0.40 for all of the policies with the exception of the limit policy.[54] The cap is more stringent in this setting, leading to high equilibrium permit and offset prices. As a consequence, the share of offsets that are non-additional is lower since more projects find it profitable to opt in and reduce emissions. Therefore the welfare cost of the second best policies is not large relative to the rent transfer.

The results appear to be insensitive to adjusting the upper bound of the marginal cost of abatement distribution for the capped and uncapped sectors. Optimal instrument choices move in intuitive directions as we adjust the bounds of the uncapped sector marginal cost distribution. A higher upper bound for the uncapped sector marginal cost distribution encourages the policy maker to relax the stringency of the offsets instruments in the second-best settings. A higher upper bound for the capped sector marginal cost distribution suggests that the policy maker sets more stringent instrument choices. This occurs as a response to a less stringent exogenous permit allocation.

Our simulation results are sensitive to our assumption for the benchmark level of non-additional offsets. This level is related to the heterogeneity in uncapped firm BAU emissions, where a greater amount of heterogeneity implies a larger fraction of non-additional offsets. In this section we vary the parameter values that set the level of heterogeneity to determine how the share of offsets that are non-additional influences our results. In the fourth panel of Table 12, we vary the benchmark share of non-additional offsets between two extreme cases: 20 percent and 60 percent. The 20 percent case represents a program that sets stringent additionality standards while the 60 percent case more closely resembles a program with relaxed standards.[55] Changing the benchmark percentage of offsets that are non-additional has a significant impact on the welfare cost per unit of avoided transfer. When the benchmark percentage is low, the cost is high because capped firm rents in the first-best setting are not much lower than they are in the second-best settings. This occurs because the baseline does not need to be adjusted up very much to encourage all uncapped firms to opt in, requiring a smaller reduction in permits to capped firms to account for the supply of non-additional offsets. Under either benchmark percentage, however, the cost per unit of avoided transfer remains below the marginal excess burden of 0.40.

Conclusion

In this paper we analyze the efficiency of several instruments in carbon offsets programs that are plagued by adverse selection. This issue has been the most controversial aspect of including offsets in climate change mitigation programs because adverse selection can destroy the integrity of emissions trading programs and in many cases some policy prescriptions involve large distributional transfers. Our analysis of three instruments – baselines, trade ratios and limits – accounts for both of these features in evaluating which combination of methods is best for dealing with adverse selection.

The paper provides several key insights. We find that the first best can be achieved by adjusting two instruments: the allocation of permits to capped firms and the uncapped firms baseline. The first-best solution, however, has significant distributional implications. It requires transferring substantial rents from capped firms to uncapped firms, a feature that may be politically difficult to implement. For this reason, we consider optimal instrument choice in a second-best setting where the policy maker cannot adjust the allocation of permits which define capped firm rents. We find that adjusting the baseline is the most preferable mechanism from an efficiency and a distributional standpoint. In particular, the baseline achieves higher welfare relative to discounting offsets or limiting the use of offsets. Finally, a binding offsets limit is never optimal from an efficiency viewpoint. The offsets limit only discourages the supply of additional offsets and under-credited emissions reductions and yields no emissions benefits.

When the allocation of permits cannot be adjusted because of distributional concerns, the second-best Baseline policy still achieves an increase in welfare relative to a policy that does not allow offsets. We quantify the distributional cost of leaving the permit allocation fixed by computing the per unit cost of avoided transfer. We find that this value is relatively small; the policy maker can avoid transferring one dollar of rents from the capped to the uncapped sector at a cost of 16 cents. This value is relatively low relative to the marginal excess burden of a labor tax of 40 cents (Gruber, 2010). We find that this result is insensitive to altering parameters of our model for two reasons. The first reason is that the first-best

[52] The quantity of allowances are reported as Permits in Table 12.

[53] Recall that in the first-best policy prescription, the cap is lowered and baselines to uncapped firms are made more generous.

[54] Recent estimates suggest that the social cost of carbon will rise to 45 dollars in the year 2050 under a three percent discount rate (EPA, 2010).

[55] There exist many types of offset standards for each offset type, with some that have more stringent application and verification requirements than others. (See Kollmuss et al., 2008 for an excellent survey of the most popular standards.) The Waxman–Markey bill did not explicitly state the type of standard that would be used to set baselines and verify offsets, so it is uncertain how stringent the offset policy would have been.

mechanism does not achieve a significant welfare improvement over the second-best outcomes because many of the low mitigation cost firms would opt in when baselines are stringent. The second reason is that the first-best mechanism requires awarding all eligible uncapped firms with a large quantity of non-additional offsets. These offsets represent the rents being transferred from the capped to the uncapped sector. Together these reasons imply that the welfare per dollar of transfers is likely to be low, regardless of the cap stringency or uncertainty in uncapped sector BAU emissions.

Some limitations of our study deserve attention.[56] First, we focus on the problem of adverse selection in markets for carbon offsets. For some types of offsets, including those from land use and land use change, carbon offsets from carbon sequestration include the problem of permanence. An offset is considered permanent if the carbon stored is not released at a later date due to natural or economic reasons. These types of offsets require a monitoring protocol well after the project has ended to ensure that the offset remains permanent. Some have suggested that these types of projects should be discounted to account for this possibility (Kim et al., 2008). For other types of offsets, carbon leakage may be severe. In most current offsets protocols including those in the CDM, offset payments are discounted to account for potential market leakage. Whether these leakage-based discount rates are optimal is uncertain and is a question that we leave for future research. Second, our model is static. The policy instruments that we consider may have significant differences with respect to how each encourages long run entry and exit in carbon offsets markets. These dynamic effects may have significant welfare consequences that are not captured by our analysis.

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Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.jeem.2014.10.003.

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[56] Although our simulation focuses on a federal United States cap-and-trade program, our results can be extended to other regional programs within the U.S. and other international schemes. For example, California recently launched its own cap-and-trade program that includes a significant offset provision. This program has placed limits on the use of offsets, a policy prescription that we suggest may actually increase the relative share of non-additional offsets supplied to capped firms. Furthermore, the flexibility mechanisms in the Kyoto Protocol permit countries to purchases offsets from developing countries to comply with the program targets. A program following the Kyoto Protocol will most likely include an offsets provision that will require setting a set of instruments aimed at balancing efficiency and distributional concerns that are illustrated in our analysis.

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How additional is the Clean Development Mechanism?

Analysis of the application of current tools and proposed alternatives

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Contents

List of boxes

List of figures

List of tables

Abbreviations

CAR	Climate Action Reserve
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CFL	Compact Fluorescent Lamp
CO_2	Carbon Dioxide
CORSIA	Carbon Offset and Reduction Scheme for International Aviation
CP	Crediting Period
CPA	Component Project Activity of a PoA
DOE	Designated Operational Entity
EB	Executive Board of the CDM
ETS	Emissions Trading Scheme/System
f_{NRB}	Fraction of non-renewable biomass
GHG	Greenhouse Gas
GS	Gold Standard
JCM	Joint Crediting Mechanism
LED	Light Emitting Diode
MP	Methodologies Panel under the CDM EB
MRV	Monitoring, Reporting & Verification
NDC	Nationally Determined Contribution
NRB	Non-renewable Biomass
OECD	Organisation for Economic Co-operation and Development
PDD	Project Design Document
PMR	Partnership for Market Readiness (Initiative of the World Bank)
PoA	Programme of Activities
UNFCCC	United Nations Framework Convention on Climate Change
USD	United States Dollar
VCS	Verified Carbon Standard

Executive summary

With the adoption of the Paris Agreement, which establishes a mechanism to contribute to the mitigation of greenhouse gas emissions and support sustainable development (Article 6.4), it is clear that the Clean Development Mechanism (CDM) as a mechanism of the Kyoto Protocol will end. However, in terms of its standards, procedures and institutional arrangements, the CDM certainly forms an important basis for the elaboration and design of future international crediting mechanisms.

While this study provides important insights to **improve the CDM up to 2020**, the approach taken in this study could **also be applied more generally both to assess the environmental integrity of other compliance offset mechanisms**, as well as to avoid flaws in the design of new mechanisms being used or established for compliance. Many of the shortcomings identified in this study are inherent to crediting mechanisms in general, not least the considerable uncertainty involved in the assessment of additionality and the information asymmetry between project developers and regulators.

A fundamental feature of both the CDM and the mechanism under Article 6.4 is that they aim to achieve environmental integrity by ensuring that only real, measurable and additional emission reductions are generated. This study analyzes the opportunities and limits of the current CDM framework for ensuring environmental integrity, i.e. that projects are additional and that emission reductions are not overestimated. It looks at the way in which the CDM framework has evolved over time, assesses the likelihood that emission reductions credited under the CDM ensure environmental integrity and provides findings on the overall and project-type-specific environmental integrity of the CDM. In addition, it provides lessons learned and recommendations for improving additionality assessment that can be applied to crediting mechanisms generally, including to mechanisms to be used for compliance under the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), and to mechanisms to be implemented under Article 6 of the Paris Agreement.

To ensure robust judgements, we have systematically analyzed the determination of additionality, the determination of baseline emissions and other issues that are key for environmental integrity. Towards this goal, we have evaluated those general CDM rules that are particularly relevant for environmental integrity and assessed in the case of specific project types the likelihood that they deliver real, measurable and additional emission reductions. Based on our analysis **key findings** include the following:

- Most **energy-related project types** (wind, hydro, waste heat recovery, fossil fuel switch and efficient lighting) are **unlikely to be additional**, irrespective of whether they involve the increase of renewable energy, energy efficiency improvements or fossil fuel switch.
- **Industrial gas projects** (HFC-23, adipic acid, nitric acid) are **likely to be additional** as long as the mitigation is not otherwise promoted or mandated through policies.
- **Methane projects** (landfill gas, coal mine methane) have a **high likelihood of being additional**.
- **Biomass power projects** have a **medium likelihood of being additional** overall because the assessment of additionality very much depends on the local conditions of individual projects.
- The additionality of the current pipeline of **efficient lighting projects** using small-scale methodologies is **highly unlikely** because in many host countries the move away from incandescent bulbs is well underway.

- In the case of **cook stove projects**, CDM revenues are often insufficient to cover the project costs and to make the project economically viable. Cook stove projects are also likely to considerably **over-estimate the emission reductions** due to a number of unrealistic assumptions and default values.

Overall, our results suggest that 85% of the projects covered in this analysis and 73% of the potential 2013-2020 Certified Emissions Reduction (CER) supply have a low likelihood that emission reductions are additional and are not over-estimated. Only 2% of the projects and 7% of potential CER supply have a high likelihood of ensuring that emission reductions are additional and are not over-estimated.

Our analysis suggests that the **CDM still has fundamental flaws in terms of overall environmental integrity**. It is likely that the large majority of the projects registered and CERs issued under the CDM are not providing real, measurable and additional emission reductions.

When considering the Paris Framework, the most important change from the Kyoto architecture is that all countries have made mitigation pledges in the form of Nationally Determined Contributions (NDC). An important implication is that host countries with ambitious and economy-wide mitigation pledges have **incentives to limit international transfers of credits** to activities with a **high likelihood of delivering additional emission reductions**, so that transferred credits do not compromise the host country's ability to reach their own mitigation targets. A second important implication is that countries should **only transfer emission reductions where this is consistent with their NDC**, implying that baselines may have to be determined in relation to the host country's mitigation pledges rather than using a 'counterfactual' business as usual scenario as a default.

Taking into account this context and the findings of our analysis, we recommend that the role of crediting in future climate policy should be revisited:

- We recommend potential buyers of CERs to limit any **purchase of CERs** to either **existing projects which risk discontinuing GHG abatement** when the incentive from the CDM ceases, such as landfill gas flaring or to new **projects among** the few project types identified t**hat have a high likelihood of ensuring environmental integrity**.

- Buyers should **accompany purchase of CERs with support for a transition of host countries to broader and more effective climate policies**. In the short–term, where offsetting is used, it should only be on the basis that purchase of CERs does not undermine the ability of host countries to achieve their mitigation pledges.

- Given the inherent shortcomings of crediting mechanisms, 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 does not result in the transfer of credits or offsetting the purchasing country's emissions. International crediting mechanisms should play a limited role after 2020, to address specific emission sources in countries that do not have the capacity to implement alternative climate policies.

- To enhance the environmental 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 such mechanisms to **project types** that have a **high likelihood of delivering additional emission reductions**. We also recommend reviewing methodologies systematically to address risks of over-crediting, as identified in this report.

- We also recommend provisions that provide strong incentives to the Parties involved to ensure the integrity of international unit transfers. This includes robust accounting provisions to **avoid double counting** of emission reductions, but could also extend to other elements, such as implementation of **ambitious mitigation pledges** as a prerequisite to participating in international mechanisms.

With the adoption of the Paris Agreement, implementing more effective climate policies becomes key to bringing down emissions quickly on a pathway consistent with well below 2°C. Our findings suggest that **crediting approaches** should play a **time-limited and niche role** focusing on those project types for which additionality can be relatively assured. Crediting should serve as a stepping-stone to other, more effective policies to achieve cost-effective mitigation. Continued support to developing countries will be key. We recommend using new innovative sources of climate finance, such as revenues from auctioning of emission trading scheme allowances, rather than crediting for compliance, to support developing countries in implementing their NDCs.

Summary

Aim of the study

With the adoption of the Paris Agreement, which establishes a mechanism to contribute to the mitigation of greenhouse gas emissions and support sustainable development (Article 6.4), it is clear that the role of the CDM as a mechanism of the Kyoto Protocol will end. However, in terms of its standards, procedures and institutional arrangements, the **CDM** certainly forms an **important basis** for the elaboration and design of future mechanisms for international carbon markets. One key feature of both the CDM and the mechanism under Article 6.4 is that they should generate **real and additional** emission reductions. In other words, emission reductions that are credited and transferred should not have occurred in the absence of the mechanism and should not be overestimated. This study analyzes the opportunities and limits of the current CDM framework and the way in which it has evolved over time and been applied to concrete projects. It provides findings on the **overall and project-type-specific environmental performance of the CDM** in the form of estimates of the **likelihood that the CDM results in real and additional emission reductions**. In addition, it provides lessons and recommendations for improving additionality assessment that can be applied to future crediting mechanisms.

Methodological approach

The main focus of this study is to assess the extent to which the CDM meets its objective to deliver “real, measurable and additional” emission reductions. In order make well-founded judgements about the overall and project-type-specific likelihood of additionality of CDM projects, we systematically analyze CDM rules and how they have been applied to real projects in practice. We examined the rules for 1) **additionality assessment**, for 2) the **determination of baseline emissions** and 3) a number of **other issues** including the length of crediting period, leakage effects, perverse incentives, double counting, non-permanence, monitoring provisions and third party validation and verification. We approach these aspects from two different perspectives: we evaluate 1) **general CDM rules** that are particularly relevant for the delivery of real, measurable and additional emission reductions and we evaluate 2) **specific project types** with a view to assessing how likely these project types deliver additional emission reductions. To assess the impacts of our analysis, we further estimate the **potential 2013-2020 CER supply** from different project types.

Project-types-specific results

Table 1-1 (p. 13) below provides an overview of the findings on environmental integrity based on the detailed analysis of individual 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 why these projects types are unlikely to be additional is that the revenue from the CDM for these project types is small compared to the investment costs and other cost or revenue streams, even if the CER prices would be much higher than today. Moreover, many projects are economically attractive, partially due to cost savings from project implementation (e.g. fossil fuel switch, waste heat recovery) or domestic support schemes (renewable power generation).

Table 1-1: 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

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 do not generate significant 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 and nitric acid projects, perverse incentives have been adequately addressed. With regard to **adipic acid** projects, the risks for **carbon leakage have not yet been 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 of **efficient lighting** projects 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. Particularly in urban areas, the additionality of these project types is questionable. Cook stove projects are also likely to considerably over-estimate the emission reductions due to a number of unrealistic assumptions and default values.

Overall environmental assessment

Based on these considerations, we estimate that **85% of the covered projects and 73% of the potential 2013-2020 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 (Table 1-1, p. 13).

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. The main reason for this 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 of these project types is only less than a quarter. A second reason is that the **CDM Executive Board (EB)** has not only improved rules but also **made simplifications** that undermined the integrity. For example, positive lists have been 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). A third reason is that the **CDM EB** did not take effective means to **exclude project types** with a low likelihood of additionality. While positive lists have been introduced, project types with more questionable additionality have not been excluded from the CDM. Standardized baselines provide a further avenue to demonstrating additionality but do not reduce the number of projects wrongly claiming additionality. The improvements to the CDM mainly aimed at **simplifying requirements and reducing the number of false negatives** but did not address the false positives.

The result of our analysis therefore suggests that the **CDM has still fundamental flaws in terms of environmental integrity**. It is likely that the large majority of the projects registered and CER 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.

Recommendations for improving general additionality rules

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. **Information asymmetry** between project developers and regulators, combined with the economic incentives for project developers to have their project recognised as additional, are a major challenge. We carefully scrutinised the **four main approaches** used to determine additionality. Our analysis shows that **prior consideration** is a necessary and important but not sufficient step for ensuring additionality of CDM projects and that this step largely works as intended. The subjective nature of the **investment analysis** limits its ability to assess with high confidence whether a project is additional. 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. The **barrier analysis** has lost importance as a stand-alone approach of demonstrating additionality. Non-monetized barriers remain subjective and are often difficult to verify by the DOEs. 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. However, the way in which common practice is currently assessed needs to be substantially reformed to provide a reasonable means of demonstrating additionality; it is important to reflect that market penetration is not for all project types a good proxy for the likelihood of additionality.

Against this background, we recommend that the **common practice analysis** is given a **more prominent role in additionality determination** though only after a significant reform:

- The 'one-size-fits-all' approach of determining common practice should be replaced by **sector- or project-type-specific guidance**, particularly with regard to distinguishing between different and similar technologies and with regard to the threshold for market penetration.

- 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.

- The common practice analysis should at least cover the **entire country**. However, if the absolute number of activities in the host country does not ensure statistical confidence, the scope needs to be extended to other countries.

- As a default, all CDM projects should be included in the common practice analysis, unless a methodology includes different requirements.

We further recommend that the **investment analysis** is excluded as an approach for demonstrating additionality for projects types in which the 'signal to noise' ratio is insufficient to determine additionality with the required confidence. For those project types in which the investment analysis would still be eligible, the project participant must confirm the all information is true and accurate and that the investment analysis is consistent with the one presented to debt or equity funders. The **barrier analysis** should be abolished entirely as a separate approach in the determination of additionality at project level (though it may be used for determining additionality of project types). Barriers that 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.

In addition, we recommend improvements to key general CDM rules:

- **Renewal and length of crediting periods:** At the renewal of the crediting period the validity of the baseline scenario should be assessed for CDM project types for which 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 should be limited to one single crediting period. Moreover, generally abolishing the renewal of crediting periods while allowing a somewhat longer single crediting period for project types that require a continuous stream of CER revenues to continue operation may be considered.

- **Positive Lists:** The 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 emission technologies (so-called E- policies). To maintain environmental integrity of the CDM overall, positive lists should be accompanied by negative lists.

- **Standardized baselines:** Once established in a country, their use should be made mandatory and all CDM facilities should be included in the peer group used for the establishment of standardized baselines.
- **Consideration of domestic policies (E+/E-):** The risk of undermining environmental integrity by over-crediting 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 being excluded from the crediting baseline where possible.
- **Suppressed demand:** 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 could be restricted to countries where development needs are highest and the potential for over-crediting is the smallest.

Recommendations to improve project type specific rules

Industrial gas projects: Adipic acid production is a highly globalised industry and all plants are very similar in structure and technology. Therefore, 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. After issues related to perverse incentives have been successfully addressed through ambitious benchmarks, **HFC-23** and **nitric acid** projects would provide for a high degree of environmental integrity. However, industrial gas projects provide for low-cost mitigation options. 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 Nationally Determined Contributions (NDCs) under the Paris Agreement. Parties to the Montreal Protocol are also considering regulating HFC emissions. We therefore recommend that HFC-23 projects are not eligible under the CDM.

Energy-related project types: We recommend **that these project types should, in principle, no longer be eligible** 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. These project types may thus remain **eligible in least developed countries**. In cases in which **biomass power generation** 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. 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.

With regard to **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, if cook stove methodologies were revised considerably, including more appropriate values for the fraction of non-renewable biomass and if approaches for determining the penetration rate of efficient lighting technologies were made mandatory for all new projects and CPAs while the older methodologies are withdrawn, we recommend that these project types should remain eligible.

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 requesting DOEs to verify that landfilling practices are not changed. With regard to landfill gas, we recommend that this project type only be eligible in countries that have policies in place to transition to more sustainable waste management practices.

Implication for the future use of international carbon markets

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, may have facilitated leapfrogging the establishment of extensive fossil energy infrastructures and created knowledge, institutions, and infrastructure that can facilitate further action on climate change. Some projects provided significant sustainable development co-benefits. Despite these benefits, after well over a decade of gathering 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. Information asymmetry between project participants and regulators remains a considerable challenge. This challenge is **difficult to address through improvements of rules**. 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. 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 for 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 they make them subsidize the reduction of emissions**. 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.

The future role of crediting mechanisms should therefore be revisited in the light of the Paris Agreement. Several **elements of the CDM could 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. The Paris Agreement therefore 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 what they had pledged under their NDC. A second important implication relates to the incentives for host countries to ensure integrity. Host countries with ambitious and economy-wide mitigation pledges would 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. In combination, 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 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. However, donors of climate finance aim to ensure that their funds be used for actions that would not go ahead without their support. Given the considerable shortcomings with the approaches for assessing additionality, we recommend that donors should not rely on current CDM rules in assessing the additionality of projects considered for funding.

Taking into account this context and the findings of our analysis, we recommend that the role of crediting in future climate policy should be revisited:

- We recommend potential buyers of CERs to limit any **purchase of CERs** to either existing **projects that are at risk of stopping GHG abatement** 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**. We further recommend to pursue the purchase and cancellation of CERs as a form of **results-based climate finance** rather than using CERs for compliance towards meeting mitigation targets.

- Given the inherent shortcomings of crediting mechanisms, 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. International crediting mechanisms should play a limited role after 2020, to address specific emission sources in countries that do not have the capacity to implement broader climate policies.

- 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** such mechanisms 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. We also recommend curtailing the length of the crediting periods with no renewal.

- Given the high integrity risks of crediting mechanisms, we recommend provisions that provide strong incentives to the Parties involved to ensure integrity of international unit transfers. This includes robust accounting provisions to **avoid double counting** of emission reductions, but could also extend to other elements, such as **ambitious mitigation pledges** as a prerequisite to participating in international mechanisms.

In conclusion, we believe that the CDM has 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 confirms, alongside other evaluations, the strong shortcomings inherent to crediting mechanisms. With the adoption of the Paris Agreement, implementing more effective climate policies becomes key to bringing down emissions quickly on a pathway consistent with well below 2°C. Our findings suggest that **crediting approaches** should play a **time-limited and niche-specific role** in which 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.

1. Introduction

With almost 7,700 Clean Development Mechanism (CDM) projects and almost 300 programmes of activities (PoAs) registered and more than 1.6 billion Certified Emissions Reductions (CER) issued, the CDM has developed into an important component of the global carbon market. However, its role in the future remains uncertain. With the adoption of the Paris Agreement, which establishes a mechanism to contribute to the mitigation of greenhouse gas emissions and support sustainable development (Article 6.4), it is clear that the role of the CDM as a mechanism of the Kyoto Protocol will end, most likely soon after 2020.

However, in terms of its standards, procedures and institutional arrangements, the CDM forms certainly an important base for the elaboration and design of future mechanisms for international carbon markets. The mechanism established under Article 6.4 of the Paris Agreement includes several provisions that are similar to the CDM. Parties also decided that the rules, modalities and procedures of the new mechanism should be adopted on the basis of the “experience gained with and lessons learned from existing mechanisms”. Moreover, experiences gained from the CDM can also be used for the development of domestic baseline and credit policies both in developed and developing countries.

One key feature of both the mechanism under the Paris Agreement (Article 6.4) and domestic baseline and credit policies is that they should generate real and additional emission reductions, in other words: the credited and transferred emission reductions should not have occurred in the absence of the mechanism and or policy. The ability to deliver such a result depends heavily on having a reasonably effective way to assess additionality both for specific project types and on an aggregate basis, and to set a baseline such that the number of credits issued does, in total, not exceed actual reductions.

Demonstrating additionality and setting baselines are the areas in which the most concerns have been raised with the CDM, in particular regarding the investment, barrier and common practice analysis and the assessment of prior consideration. Given its counterfactual nature, asymmetries of information regarding costs, financing, barriers and local project conditions, and signal-to-noise issue, it has been difficult to implement a reliable method for assessing additionality and setting baselines. Other factors that also affect the overall mitigation outcome are the length of the crediting period used, how leakage concerns are dealt with and whether any perverse incentives are addressed, among others.

The difficulties with these traditional approaches have resulted in further refinement and revision of these approaches as well as the introduction of several alternative approaches to setting of baselines and testing additionality. Examples include the use of default values, performance benchmarks or penetration rates and discounting approaches. More fundamental changes include the use of highly standardized baselines and additionality tests at the sectoral level. It remains to be seen whether the methodological difficulties with highly standardized approaches can be solved to make them operational, and whether they will result in a lower likelihood of non-additional credits being issued.

The additionality of CDM projects has been assessed in the past in several general and project-specific studies. Much of the research was conducted before the improvement of rules and the introduction of new approaches, such as standardized baselines. This study aims to assess whether and how these changes have affected the quality of CDM projects, focusing on the project portfolio available in the second commitment period of the Kyoto Protocol and taking due account of the improvements implemented over time.

In order to make well-founded judgements about the overall and project-type-specific likelihood of additionality of CDM projects, a systematic assessment is required of the CDM rules and how they have been applied to real projects in practice. A similar exercise should be carried out for the different reforms suggested to the existing rules. This study therefore analyzes the opportunities and limits of the current CDM framework and the way in which it has evolved over time and been applied to concrete projects. It provides robust and quantified conclusions on the overall and project-type-specific environmental performance of the CDM in the form of estimates of the likelihood that the CDM results in real and additional emission reductions.

2. Methodological approach

2.1. General research approach

The main focus of this study is to assess the extent to which the CDM meets its objective stipulated in Article 12.5(c) of the Kyoto Protocol to deliver "real, measurable and additional" emission reductions. Based on the findings, concrete recommendations are made for further reform of the CDM and implications for the future role of the CDM are discussed.

There are two principal challenges to evaluating of the ability of the CDM to deliver additional emission reductions: the inherent uncertainty of a counter-factual baseline and the uncertainty and bias associated with project and baseline data. Therefore, any assessment of the extent of non-additional or otherwise under- or over-credited CDM activity can therefore only provide rough and directional estimates. Project design documents (PDDs) and monitoring reports provide substantial data and assumptions. However, these data and assumptions are often limited (they may not cover all relevant activity, especially non-CDM activity) and can involve considerable judgment by parties that have an interest in the outcome (e.g. selecting among alternative projections of future fuel prices) made for the purpose of meeting CDM requirements.

We examine the three main aspects as regards whether the CDM delivers additional emission reductions:

1. **Additionality assessment:** The assessment of additionality refers to the question of whether a project was implemented due to the CDM. Additionality is the most important prerequisite to providing an emissions benefit. If a project would have been implemented in the absence of the CDM incentives, the emission reductions would have occurred anyway. If a Party uses non-additional CERs rather than reducing its own emissions to meet its emission reduction commitments, global GHG emissions would be higher than they would have otherwise been. Because errors in additionally determination affect the validity of an entire project's CERs, additionality assessment forms the main focus of this study.

2. **Determination of baseline emissions:** A second important aspect is how the baseline emissions are determined. Determining baseline emissions is associated with considerable uncertainty. A crediting baseline that is above the emissions that would most likely occur in the absence of the project can lead to significant over-crediting. Vice versa, ambitious baselines that are below the emissions that would most likely occur in the absence of the project, can result in under-crediting.

3. **Other issues:** A number of other issues are important to deliver additional emission reductions, including:

   - the length of crediting period,
   - criteria for the renewal of the crediting period,

- approaches for determining indirect emission effects, such as leakage effects,
- the way in which perverse incentives for both project developers and policy makers are addressed,
- the extent to which double counting of emission reductions within the mechanism and with other mechanisms and pledges is avoided,
- whether potential non-permanence of emission reductions is sufficiently addressed,
- whether monitoring provisions are appropriate, and
- the effectiveness of the regulatory framework for third party validation and verification.

We also touch upon these issues, in particular when they raise concerns with regard to the integrity of the CDM. They do not, however, form the focus of this study.

In our examination, we approach these aspects from two different perspectives:

- **General CDM rules:** In Chapter 3, we evaluate approaches for determining general CDM additionality rules that are particularly relevant for the delivery of real, measurable and additional emission reductions. This includes an assessment of innovative and potentially more objective approaches for setting baselines and determining additionality and an analysis of whether and how these approaches could improve the determination of additionality under the CDM.

- **Specific project types:** In Chapter 4, we evaluate specific project types with a view to assessing how likely these project types deliver additional emission reductions. A separate evaluation by project type is important as the likelihood of additional emission reductions can differ significantly among project types. This evaluation covers the major project types contributing to a large share of the emission reductions in the CDM portfolio.

Drawing on findings from Chapters 3 and 4, we provide an overall assessment of the additionality of the CDM project portfolio in Chapter 5. In Chapter 6, we provide a summary of key recommendations for further reform of the CDM. Finally, we discuss the implications for the future use of the CDM in Chapter 7.

The study employs several analytical methodologies and approaches:

- **Literature analysis** forms the basis for our evaluation of general CDM rules, specific project types, and innovative approaches towards baseline setting and additionality assessment.

- **Qualitative assessment of relevant CDM rules** with a view to their ability for ensuring additional emission reductions. We identify potential shortcomings in the current rules and propose options for addressing them.

- **Empirical, quantitative evaluation of how the CDM rules are applied** through analysis of a representative random sample of projects. The analysis will be based on information in PDDs and validation reports and, where necessary, also monitoring and verification reports. The projects will be identified through stratified random sampling, aiming to ensure representativeness of host countries and project types. This empirical analysis aims to identify possible shortcomings in the application of general CDM rules. The information and data to be evaluated is specific for each of the identified general CDM rules and the questions identified. The methodological approach of the empirical evaluation is further specified in Section 2.2 below.

- **Economic assessment** of the feasibility of different project types is another important building block of the study. The economic assessment is conducted for the evaluation of specific project types in Chapter 4. The methodological approach of the empirical evaluation is further specified in Section 2.3 below.

- **Sectoral analysis** of the market situation for specific project types to assess whether the technology has often already been implemented without the CDM and whether an observed market uptake occurs due to the CDM. The sectoral analysis is conducted for the evaluation of specific project types in Chapter 4. The methodological approaches are further specified in the corresponding sections.

We use the CDM rules and the CDM project portfolio as of 1 January 2014 as the basis for the assessment.

To assess the impacts of our analysis, we further estimate the potential 2013-2020 CER supply for different project types. The method used to estimate the potential CER volume is described in Section 2.3.

2.2. Empirical evaluation of CDM projects

The assessment of key CDM rules for additionality demonstration in Chapter 3 is based on an in-depth evaluation of PDDs, validation reports, etc. of randomly selected CDM projects. The project samples were randomly drawn from the so-called CDM project pipeline as of 1 January 2014 (UNEP DTU 2014). This pipeline is a compilation of certain information and data provided in the project design document (PDD) of each CDM project. For this assessment, only registered CDM projects were taken into account as the PDDs usually undergo significant changes during the validation period. To ensure representativeness, the samples were stratified by the following characteristics and strata:

- Location (host country/region)
  - China
  - India
  - Asia & Pacific
  - Brazil
  - Latin America
  - Rest of the World
- Technology
  - Industry (HFC-23, N_2O, cement, energy efficiency, energy distribution, etc.)
  - Electricity generation from hydro
  - Electricity generation from wind
  - Electricity generation from renewable energy (solar, tidal, etc.)
  - Other renewable energy (biomass, geothermal, mixed renewable energy, etc.)
  - Waste sector (landfill gas, methane avoidance, etc.)
  - Other (afforestation, reforestation, agriculture, transport, etc.)
- Scale
  - Large-scale projects
  - Small-scale projects
- Time (registration year)
  - Pre 2010
  - In 2010 or 2011
  - Post 2011.

The in-depth assessment of project samples was conducted for the key additionality determination rules: investment analysis (Section 3.2), barrier analysis (Section 3.3) and common practice analysis (Section 3.3). For each of these rules a separate sample of 30 randomly selected CDM projects was drawn.

Since the CDM project pipeline did not include information about which option of additionality determination was applied in the PDD, we had to conduct a two-step sampling: In the first step, we drew a representative sample of 300 projects. For each of the projects of this sample we identified which additionality determination rules were applied so that we could use this sample as population for the second sampling step in which we drew the samples for each of the additionality determination rules.[1]

2.3. Estimation of the potential CER supply

We estimate the potential CER supply[2] for the purpose of assessing the overall integrity of the CDM based on our findings for specific project types or specific additionality tests. The potential CER supply is estimated mainly on the basis of the CDM pipeline as of 1 January 2014 (UNEP DTU 2014). Moreover, we included additional information from a similar pipeline which is provided by IGES (2014). All CDM projects which were registered by 1 January 2014 are taken into account (7,418). In the case of industrial gas projects (HFC-23, adipic acid, nitric acid), some baseline and monitoring methodologies were significantly revised, which has a major impact on the potential CER supply in the second and third crediting periods. For these projects, we use specific bottom-up estimates derived from project-specific information (Schneider & Cames 2014).

We distinguish the CER supply potential considering the duration of the commitment periods under the Kyoto Protocol:

- from credit start to the end of 2012,
- from the beginning of 2013 to the end of 2020 and
- from the beginning of 2021 to the end of the crediting periods (CP).

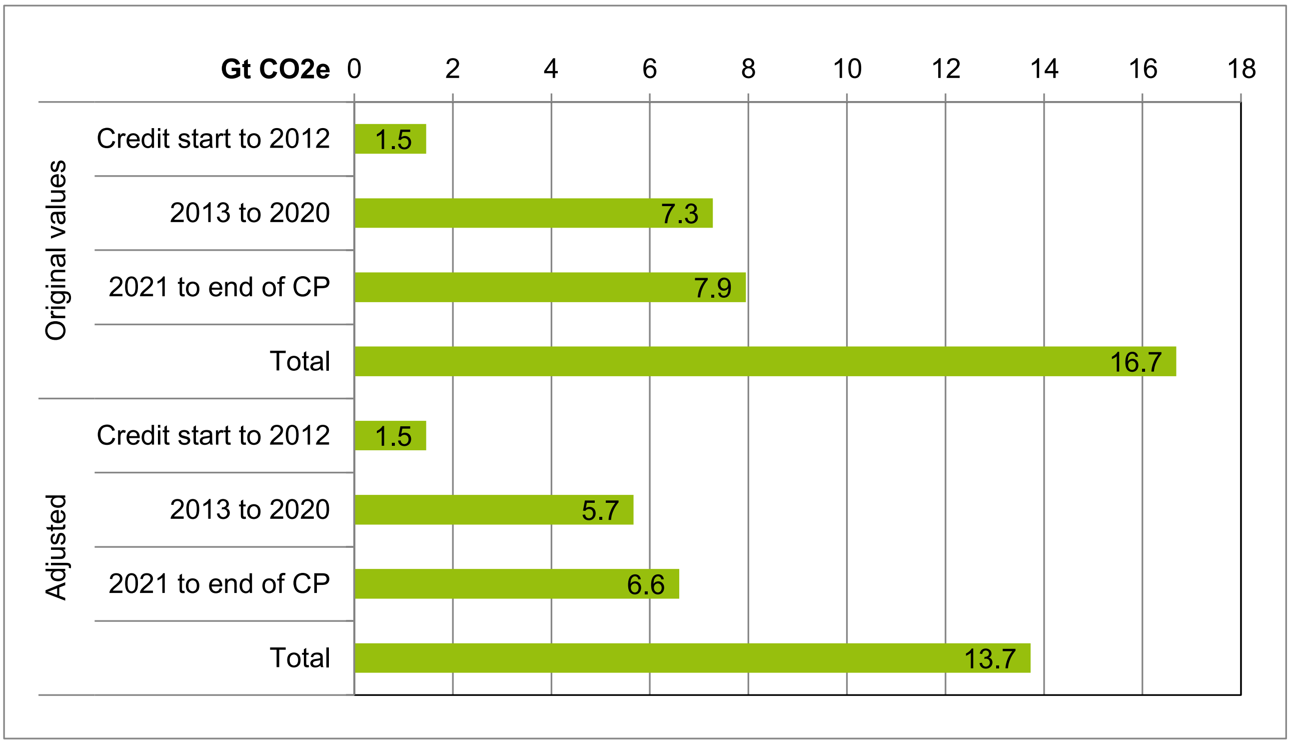
Our study is focused on the period of 2013 to 2020.

Figures for the period from credit start to the end of 2012 reflect the actual CER issuance rather than the potential supply (UNFCCC 2015a). For the latter two periods, we take into account the issuance success rate provided in the CDM pipeline and adjust the expected CER supply accordingly. For some projects, more CERs were issued than projected while for most of the CDM projects less CERs were issued. Several projects had not issued any CERs (4,913). For those projects we assume either the average issuance rate for the respective project type or – if no CERs have been issued for that project type so far – the overall average of the issuance success rate. Figure 2-1 provides an overview of the potential CER supply.

[1] A more detailed description of the sampling approach, the code used for drawing the samples and the reference numbers of the projects drawn into each of the samples can be found in Section 8.1 of the Annex.

[2] The actual CER supply depends on various conditions of the global carbon market and particularly on price expectations. However, also under normal market conditions, price forecasts are very uncertain. Under post-2012 market conditions, prices are even more uncertain. We therefore only estimate the potential CER supply which is derived from information in PDDs and other project specific or general documents but ignore any interaction with the global carbon market. At price levels of less than $1/CER, the estimated volumes will not be achieved in practice.

Figure 2-1: Potential CER supply, original and adjusted values

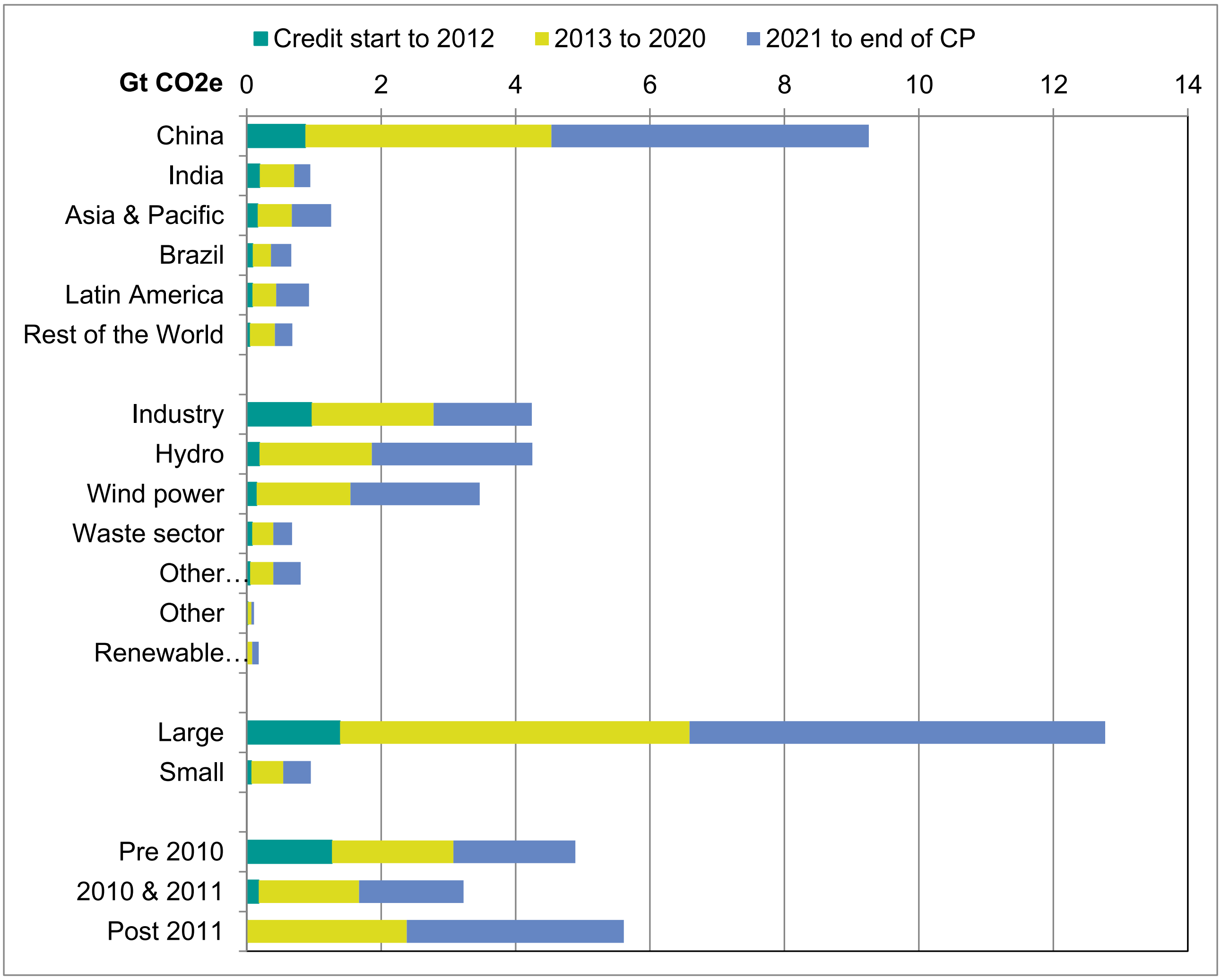


Sources: UNEP DTU 2014, IGES 2014, UNFCCC 2015a, Schneider & Cames 2014, authors' own calculations

The average adjustment factor is -22% though it ranges from -4% for N_2O projects to some -67% for transport projects. The adjusted CER supply for the period of 2013 to 2020 amounts to almost 5.7 billion CERs, almost 4 times the volume issued for the first crediting period.

Figure 2-2 illustrates where the potential CER supply stems from. Obviously China was and will remain the largest potential supplier of CERs. Almost two thirds (64.5%) of the potential CER supply in 2013 to 2020 are expected to be provided by Chinese CDM projects. In terms of project types, the large majority of supply stems from industry (32.0%), hydro (29.4%) and wind (24.6%) projects. Not surprisingly, the large majority (91.3%) of CERs stems from large scale projects while the breakdown in terms of registration period is more even: 31.8% stems from projects registered before 2010, 26.3% from projects registered in 2010 and 2011 while 41.8% of the potential CER supply in the period of 2013 to 2020 can be generated from CDM projects registered after 2011.

Figure 2-2: Potential CER supply by stratification categories



Sources: UNEP DTU 2014, IGES 2014, UNFCCC 2015a, Schneider & Cames 2014, authors' own calculations

In Chapter 4 we analyze the extent to which the likelihood of projects and CERs being additional depends on the project type. We look at 12 different project types, which together cover a broad range of activities and technologies. In terms of CER supply, these 12 project types amount to 85% of the potential supply in the period of 2013 to 2020 (Table 2-1). The largest supply potential is provided by hydro and wind power projects (29.4% and 24.6%, respectively). Industrial gas projects amount to almost 15% of the supply potential while biomass power, landfill gas, waste heat recovery and fossil fuel switch projects could each generate some 3-4% of the supply potential. Compared to these projects types the supply potential of cook stoves (0.04%) and efficient lighting (0.07%) are almost negligible. However, since these project types are often included in government purchase programs or voluntary offset schemes and since their share among projects registered after 2012 is significant, we consider it worthwhile to examine these two project types in greater depth and to assess their likelihood of being additional and of generating additional CERs.

Table 2-1: Potential CER supply by project type

	No. of projects	Credit start to 2012	2013 to 2020	2021 to end of CP Adjusted	Total
		Mt CO_2e			
HFC-23 abatement from HCFC-22 production	19	507	375	547	1,429
Adipic acid	4	201	257	269	727
Nitric acid	97	57	175	172	404
Hydro power	2,010	191	1,669	2,388	4,249
Wind power	2,362	148	1,397	1,929	3,475
Biomass power	342	25	162	169	355
Landfill gas	284	57	163	159	380
Coal mine methane	83	34	170	123	327
Waste heat recovery	277	63	222	62	346
Fossil fuel switch	96	51	232	175	458
Cook stoves	38	0.1	2.3	0.4	2.7
Efficient lighting	43	0.4	3.8	0.2	4.5
Not covered	1,763	124	842	603	1,569
Total	7,418	1,459	5,671	6,596	13,726

Sources: UNEP DTU 2014, IGES 2014, UNFCCC 2015a, Schneider & Cames 2014, authors' own calculations

The first Programme of Activities (PoA) was registered in July 2009. From then until the end of 2013, 243 PoAs were registered in total, the large majority of them in 2012 (193). While cook stoves and efficient lighting account for only a small share in the CDM project pipeline, they are quite relevant in the context of PoAs. By the end of 2013, they account together for a quarter of the registered PoAs. Table 2-2 provides a breakdown of the potential CER supply from PoAs by project types.

Table 2-2: Potential CER supply from PoAs

	No. of programs	Credit start to 2012	2013 to 2020	2021 to end of CP	Total
		Mt CO_2e			
Hydro power	26		5	13	17
Wind power	24		18	45	63
Landfill gas	4	0	12	27	40
Coal mine methane	2		5	10	15
Fossil fuel switch	2		0	0	0
Cook stoves	31	0	33	82	115
Efficient lighting	30	2	17	63	82
Not covered	124	0	70	144	214
Total	243	2	161	385	547

Sources: UNEP DTU 2014, UNFCCC 2015b, authors' own calculations

The main difference of PoAs compared to projects bundles is that PoAs can – once registered – be extended over time by an unlimited number of so-called component project activities (CPA). An estimate of the CER supply potential is thus less reliable than the estimate for the project pipeline.

However, taking into account all CPAs included in PoAs by the end of 2013, the potential CER supply can roughly be estimated, though it is obvious that the actual supply could be much higher. PoA volumes are much more difficult to estimate, because a PoA might be registered with only one CPA that has 1,000 tCO_2 per year emissions reductions but which may ultimately include CPAs that reduce hundreds of thousands of tCO_2 per year.

Noting these limitations, all PoAs could supply some 0.16 billion CERs in total in the period of 2013 to 2020. The final volume of these PoAs could be many times this amount. Almost a third (31.4%) of this supply would be provided by cook stove or efficient lighting PoAs. CERs from renewable power generation programmes amount to 14% of the supply potential of PoAs. Interestingly, almost half of the PoAs do not fall into the project type categories which together account for 85% of the potential CER supply from CDM projects. This supports the hypothesis that PoAs address project categories or technologies that cannot be adequately addressed by individual CDM projects.

2.4. Economic assessment of CER impact

The demonstration of additionality has been a key issue in the CDM since the beginning of the Kyoto mechanisms (Chapter 3). While most researchers agree that there is no simple and objective approach to determining additionality, several authors argue that the impact of CER revenues on the economic feasibility of projects is an important indicator for the likelihood for projects to be additional (for example Sutter 2003, Schneider 2007, Spalding-Fecher et al. 2012). This builds on the assumption that project proponents are more likely to implement a project due to the CDM if CER revenues have a significant impact on the economic performance of the project. While other benefits from the CDM (e.g. the public relation aspect of registering a project under the UNFCCC) may in some cases help projects to go ahead that would not be implemented in the absence of the CDM, the economic benefit of CER revenues may be considered the main driver to implement CDM projects on a larger scale.

A high economic benefit resulting from CER revenues does not guarantee additionality, because some projects may already be economically viable without CER revenues and may only become more profitable with the CDM. However, low CER revenues are an indicator of a lower likelihood that the project is additional, because with low CER revenues it also becomes more likely that the project would be implemented in the absence of the CER revenues.

In 2005, the CDM Executive Board (EB) decided that, in order to be additional, projects have to demonstrate that they are economically unattractive; however, they are not required to demonstrate that with CER revenues they would become economically viable. Schneider (2007) highlighted that this leads to the situation in which projects with very low CER revenues can prove additionality even though the CER revenues contribute only marginally to closing the profitability gap.

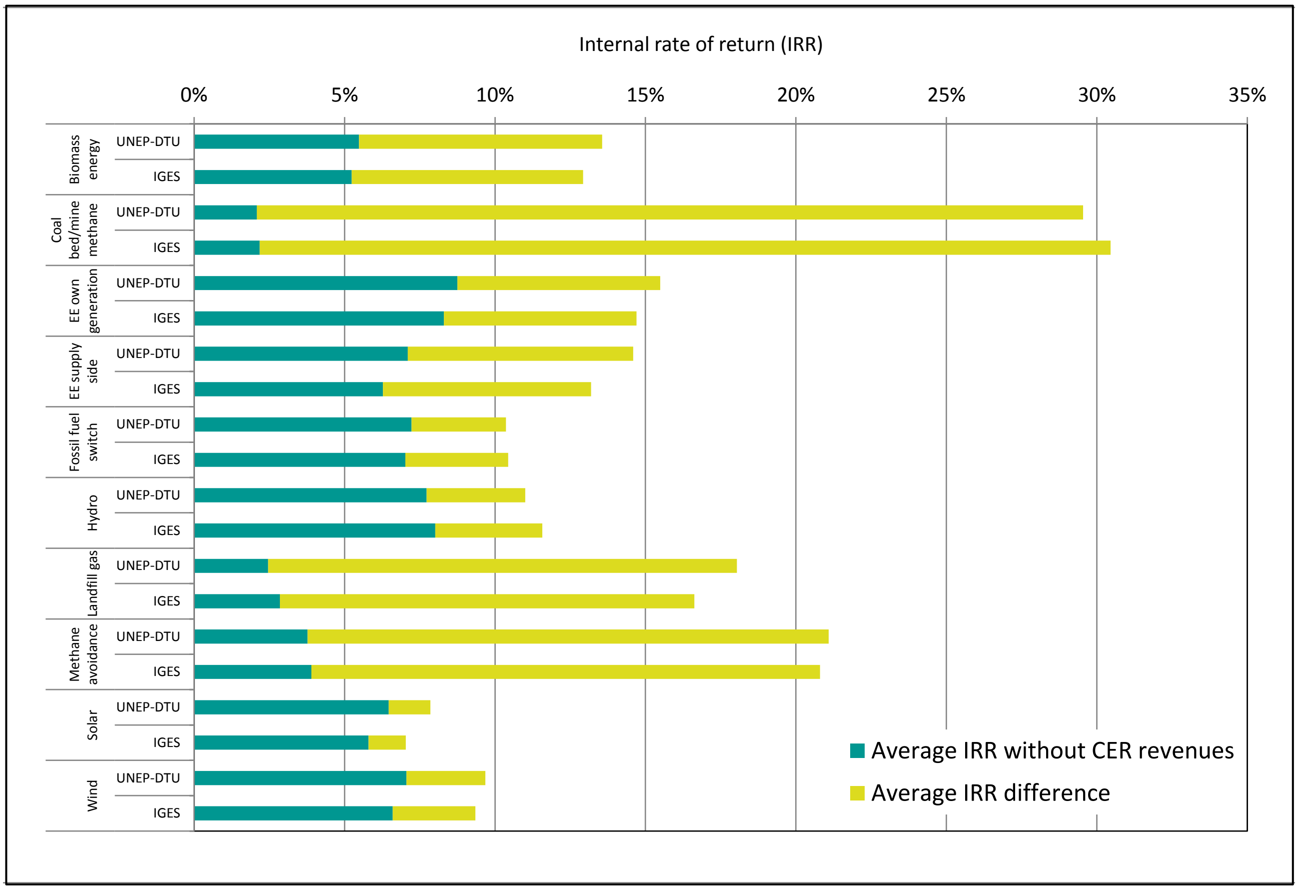
It is difficult to define a minimum required level of contribution from CER revenues that is needed to trigger an investment decision. An important concept in this context is the *signal-to-noise ratio* issue for investment analysis, as mentioned by, for example, Spalding-Fecher et al. (2012): The generally high variability and uncertainty of key parameters that determine the profitability of a mitigation project is often considerably higher than the expected economic benefit of CERs. If the economic impact of the CERs is lower than key uncertainties in the investment analysis, it is rather unlikely that the registration under the CER was the conclusive trigger for the investment and, hence, it is likely that the project is non-additional.

Table 2-3: Impact of CER revenues on the profitability of different project types

Type	Source	Projects with available IRR information	Average IRR without CER revenues	Average IRR with CER revenues	Average IRR difference
Biomass energy	UNEP-DTU	271	5.5%	13.6%	8.1%
	IGES	216	5.2%	12.9%	7.7%
Coal bed/mine methane	UNEP-DTU	70	2.1%	29.5%	27.5%
	IGES	75	2.2%	30.5%	28.3%
EE own generation	UNEP-DTU	205	8.8%	15.5%	6.7%
	IGES	202	8.3%	14.7%	6.4%
EE supply side	UNEP-DTU	36	7.1%	14.6%	7.5%
	IGES	23	6.3%	13.2%	6.9%
Fossil fuel switch	UNEP-DTU	47	7.2%	10.4%	3.1%
	IGES	39	7.0%	10.4%	3.4%
Hydro	UNEP-DTU	1,753	7.7%	11.0%	3.3%
	IGES	1,635	8.0%	11.6%	3.6%
Landfill gas	UNEP-DTU	183	2.5%	18.0%	15.6%
	IGES	165	2.8%	16.6%	13.8%
Methane avoidance	UNEP-DTU	203	3.8%	21.1%	17.3%
	IGES	204	3.9%	20.8%	16.9%
Solar	UNEP-DTU	154	6.5%	7.9%	1.4%
	IGES	122	5.8%	7.0%	1.2%
Wind	UNEP-DTU	2,162	7.1%	9.7%	2.6%
	IGES	1,804	6.6%	9.4%	2.8%

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

Figure 2-3: Impact of CER revenues on the profitability of different project types



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

Information on the impact of CER revenues on economic profitability is available from different sources. Table 2-3 and Figure 2-3 show the impact based on data included in project design documents and as documented in the databases by UNEP DTU (2014) and IGES (2014). In addition, Lütken (2012) has analyzed the annual CER revenues in relation to the capital investment and observed for some project types a (very) limited impact stemming from CER revenues. Spalding-Fecher et al. (2012) analyze the impact of CER revenues on the project IRR for different project types in the IGES database. They conclude that the CER impact on the project IRR is the lowest for renewables including hydro and wind (increase of IRR by 2-3%), fuel switch (4%), and supply-side efficiency (5%). They also provide an overview of more studies analysing the impact of CER revenues for different project types. The relatively low impact of CER revenues compared to other cash flows that are relevant for investment decisions is shown for energy efficiency projects below (Box 2-1).

Overall, the available information shows that the impact of CER revenues on the economic performance of projects varies considerably between project types:

- **Non-CO_2 projects**, such as industrial gas abatement, manure management, waste water treatment, landfill gas utilisation and coal mine methane capture, are characterised by a medium to high impact of CER revenues. For several of these project types, CER revenues increase the IRR by more than 10 percentage points, and for coal mine methane projects even by more than 25 percentage points. For these project types, the CER revenues clearly make a difference, which indicates a higher likelihood of additionality.

- **CO_2 projects in renewable energy** such as wind and hydro projects are characterised by a relatively low impact of CER revenues: for wind power, the IRR increases by about 2.5% to 3%, for hydropower by about 3% to 4%, and for solar by about 1% to 1.5%. According to Lütken (2012), the annual CER revenues in relation to investment costs (median) amounted to 1.84% for wind and 3.5% for hydro. Given the typical uncertainties surrounding costs and load factor in renewable projects, this level of CER contributions seems relatively low to justify that the project would not have been implemented in the absence of the CDM. Therefore, in many cases, the additionality of projects within these types may seem rather unlikely (though in some cases it may not be ruled out that additional CER revenues of +3.5% may be the decisive factor rendering a project attractive – though it may not be possible to prove this in an objective way). In addition, many renewable energy projects – in particular hydropower – show a relatively high economic performance without CER revenues (e.g. an IRR of nearly 8% for hydropower without CER revenues), compared to non-CO_2 projects (e.g. landfill gas, coal mine methane and methane avoidance with an IRR of about 2% to 4% without CER revenues).
- **CO_2 projects in fuel switch, energy efficiency, and waste heat utilisation** are typically characterised by relatively low investment costs. Thus, CER revenues are higher compared to investment costs (5% for waste heat and 20% for fuel switch – median value). The impact of CER revenues on the internal rate of return is about 3 to 8 percentage points. However, in this project type, fuel prices are the decisive element determining its profitability. Box 2-1 compares the impact of typical fuel costs and CER revenues for energy efficiency projects. Our analysis indicates that CER revenues tend to have a low impact on project profitability. In addition, these project types show a relatively good economic performance without CER revenues, compared to non-CO_2 projects.

Lütken's analysis was based on a CER price of €12. Our analysis in Table 2-3 and Spalding-Fetcher's build on PDD data with similar CER price assumptions. With today's much lower CER prices, the low impact of CER revenues on CO_2 projects and therefore their high risk of non-additionality is further aggravated.

In conclusion, non-CO_2 projects are characterised by a medium-to-high impact of CER revenues and a relatively low economic performance without CER revenues, while for most CO_2 project types the impact of CER revenues is much smaller and the performance without CER revenues higher. Overall, this indicates that on average non-CO_2 projects have a higher likelihood of additionality.

Box 2-1: An analysis of the impact of CER revenues for energy efficiency projects

Another way of assessing the relevance of CER revenues in investment decisions is to compare them to other important revenues or savings in the investment analysis. For instance, for energy efficiency projects to become profitable, they have to (i) save sufficient costs for fossil fuels and (ii) earn sufficient CERs to pay back the investment costs for new equipment improving the energy efficiency. Figure 2-1, Figure 2-2 and Figure 2-4 illustrate the order of magnitude of fuel cost savings in relation to one tonne of CO_2 reduced or CERs generated in the case of projects saving natural gas, light fuel oil and steam coal. For instance, if an installation implements new equipment that reduces the specific consumption of natural gas and the related GHG emissions by one tonne of CO_2, then the related reduction in fuel costs in 2010 would amount to approx. 150 USD/tCO_2 (at OECD average prices in 2010). For light fuel oil, the fuel cost reduction amounts to over 250 USD/tCO_2 and for steam coal, the savings still amount to 37 USD/tCO_2 (in 2010). With this, it becomes obvious that the impact of fuel cost savings on the project cash flow is much higher than contribution from CER revenues.

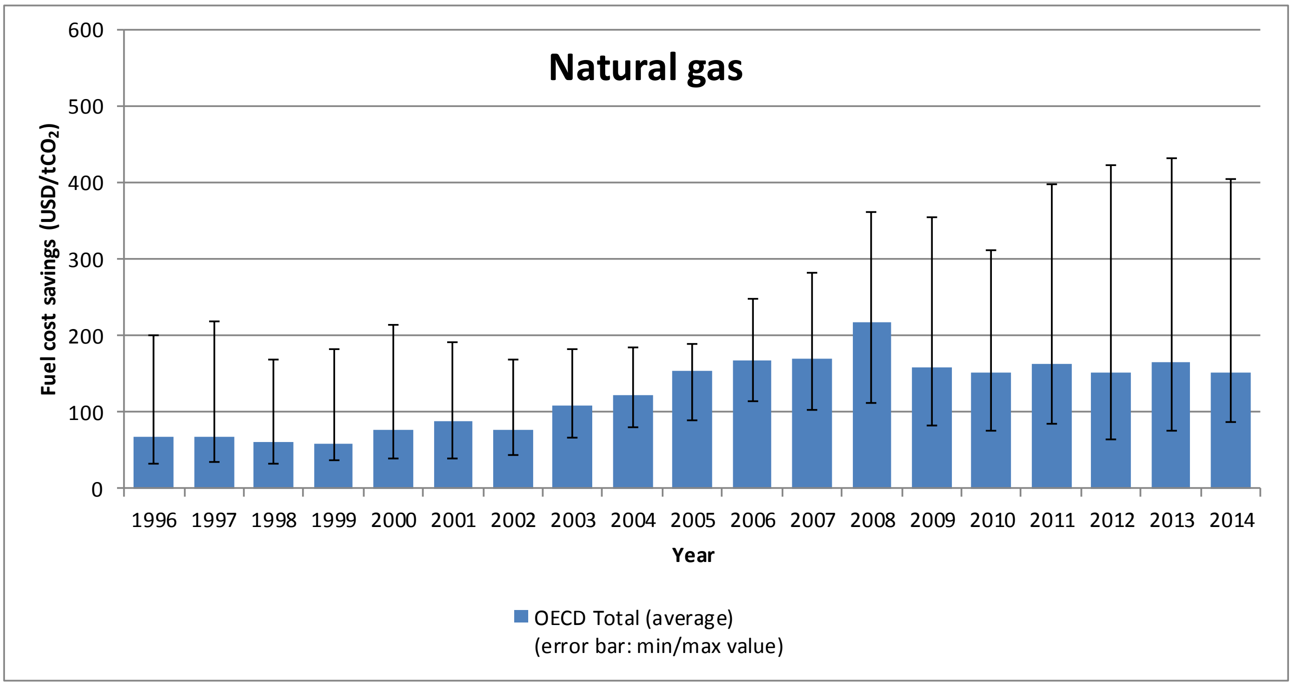
Figure 2-1, Figure 2-2 and Figure 2-4 also show the development of average (and min. and max.) OECD prices over time, which illustrates the high variability of energy prices since 1996. Average specific energy prices have fluctuated in the order of 20 USD/tCO_2 (steam coal) to 200 USD/tCO_2 (light fuel oil). Also compared to the historic fuel price variability, typical CER revenues are low to negligible compared to fuel cost savings.

Please note that because of limitations in data availability, the figures are based on fuel prices in OECD countries, which in many cases also include taxes and may not be representative for all developing countries. In particular, in some developed and developing countries fossil fuel subsidies are very high. In these cases, because of the low prices, the fuel cost savings are low and may be on a similarly low level as the contribution from CER revenues to the positive project cash flow. However, in such a low price situation, the total positive cash flow may in any case be far too small to justify investments in energy efficiency equipment and the scope for CDM may become rather limited.

Overall, it may be argued that for projects to have a high likelihood of additionality the impact of CER revenues should at least be comparable to the main contributor to a positive cash flow, the related fuel savings. This would indicate that in such project types CER prices for energy efficiency projects would need to reach a level of at least 10-20 USD/tCO_2 for steam coal, 30-50 USD/tCO_2 for natural gas and 100-200 USD/tCO_2 for light fuel oil based systems (if prices on the level of OECD countries are assumed). With such CER prices, the economic contribution from CER revenues to positive cash flow reaches a level that may be considered significant (i.e. in the order of ¼ to ½ of fuel cost savings).

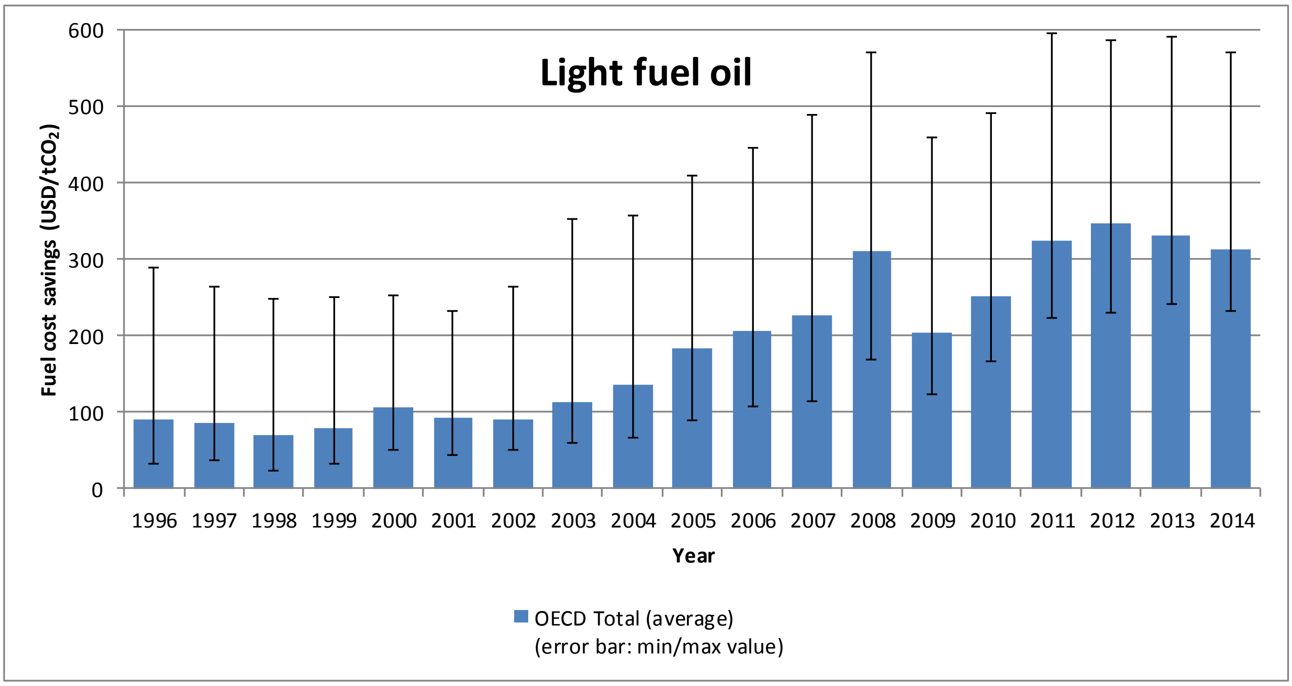
At prices significantly below this level, the economic impact of CERs is insignificant and the risk of non-additionality is very high.

Figure 2-4: Natural gas cost savings per tonne of CO_2 reduced in energy efficiency projects



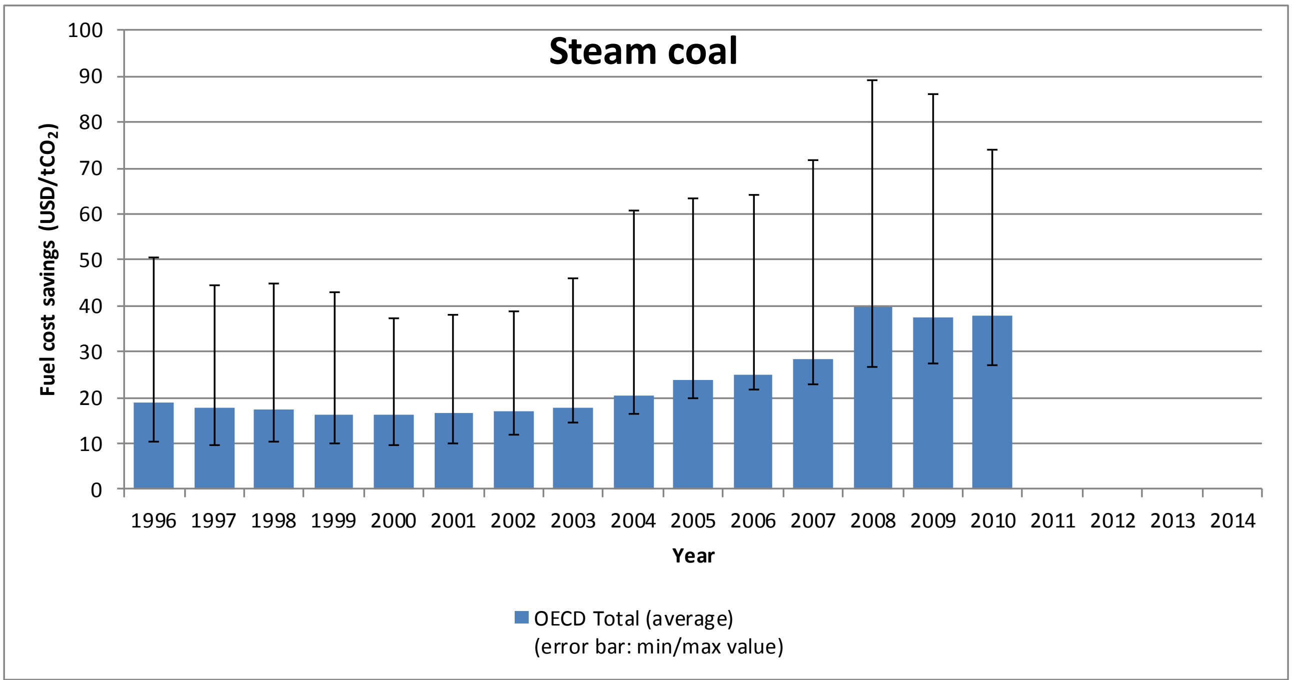
Notes: Average fuel prices of OECD countries (in USD/TJ).
Sources: IEA 2015, IPCC 2006, authors' own calculations

Figure 2-5: Light fuel oil cost savings per tonne of CO_2 reduced in energy efficiency projects



Notes: Average fuel prices of OECD countries (in USD/TJ).
Sources: IEA 2015, IPCC 2006, authors' own calculations

Figure 2-6: Steam coal cost savings per tonne of CO_2 reduced in energy efficiency projects



Notes: Average fuel prices of OECD countries (in USD/TJ).
Sources: IEA 2015, IPCC 2006, authors' own calculations

3. Assessment of approaches for determining additionality and rules relevant towards additionality

3.1. Prior consideration

3.1.1. Overview

Prior consideration is a key requirement in the CDM. It aims to ensure that only projects are registered in which the CDM was seriously considered when the decision to proceed with the investment was made.

In the first version of the additionality tool prepared in 2004[3], a provision was introduced for projects with a crediting period starting prior to registration, which stipulated that evidence has to be provided "that the incentive from the CDM was seriously considered in the decision to proceed with the project activity" and that the "evidence shall be based on (preferably official, legal and/or other corporate) documentation that was available to third parties at, or prior to, the start of the project activity." The provision remained almost unchanged in the second version of the additionality tool in 2005.

In the third version of the additionality tool in 2007, the provision was removed and then included in the Guidelines for completing the PDD, which are applicable to all projects and not only those applying the additionality tool. These guidelines stipulated that "project proponents shall provide an implementation timeline of the proposed CDM project activity" and that "the timeline should include, where applicable, the date when the investment decision was made, the date when construction

[3] EB 16, Annex 1: Tool for the demonstration and assessment of additionality.

works started, the date when commissioning started and the date of start-up (e.g. the date when commercial production started)". Also, according to the guidelines, "project participants shall provide a timeline of events and actions, which have been taken to achieve CDM registration, with description of the evidence used to support these actions"[4].

In 2008, the CDM EB introduced general guidance on the demonstration and assessment of prior consideration[5]. The guidance was subsequently revised twice[6], including further guidance for DOEs on how to validate real and continuing actions; in 2011 it was incorporated in the project standard (PS)[7]. According to the latest version of the project standard[8], "if the start date of a proposed CDM project activity … is prior to the date of publication of the PDD for the global stakeholder consultation, project participants shall demonstrate that the CDM benefits were considered necessary in the decision to undertake the project as a proposed CDM project activity". More specifically, project participants of project activities with a starting date on or after 2 August 2008 *"shall inform the host Party's designated national authority (DNA) and the secretariat of their intention to seek CDM status in accordance with the Project cycle procedure"*, while "for a proposed CDM project activity with a start date before 2 August 2008 and prior to the date of publication of the PDD for global stakeholder consultation, project participants shall demonstrate that the CDM was seriously considered in the decision to implement the proposed project activity". For this purpose, "project participants shall provide evidence of their awareness of the CDM prior to the start date of the proposed project activity, and that the benefits of the CDM were a decisive factor in the decision to proceed with the project"[9], *"provide evidence that continuing and real actions were taken to secure CDM status for the proposed project activity in parallel with its implementation"*[10] and "provide an implementation timeline of the proposed CDM project activity. The timeline should include, where applicable, the date when the investment decision was made, the date when construction works started, the date when commissioning started and the date of start-up (e.g. the date when commercial production started). Project participants shall provide a timeline of events and actions, which have been taken to achieve CDM registration, with description of the evidence used to support these actions".

The CDM project cycle procedure[11] includes details about the notification process related to prior consideration (i.e. forms to be used, etc.). According to this procedure, for project activities with a start date on or after 2 August 2008, notification to the DNA of the host country and to the Secretariat must be made "within 180 days of the start date of the project activity". A list of notifications received by the Secretariat is available on the UNFCCC website.[12]

The requirements for demonstrating prior consideration set out in the project standard are generally applicable with the exception of programmes of activities (PoAs).

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4 EB 41, Annex 12: Guidelines for Completing the Project Design Document (CDM-PDD) and the Proposed New Baseline and Monitoring Methodologies (CDM-NM) (Version 07).

5 EB 41, Annex 46: Guidance on the Demonstration and Assessment of Prior Consideration of the CDM.

6 EB 48, Annex 61 and EB 49, Annex 22.

7 EB 65, Annex 5.

8 CDM project standard, Version 07.0, EB 79, Annex 3.

9 Relevant evidence could, for instance, relate to "minutes and/or notes related to the consideration of the decision by the EB of Directors, or equivalent, of the project participants, to undertake the project as a CDM project activity".

10 Relevant evidences "should include one or more of the following: contracts with consultants for CDM / PDD / methodology / standardized baseline services; draft versions of PDDs and underlying documents such as letters of authorization, and if available, letters of intent; emission reduction purchase agreement (ERPA) term sheets, ERPAs, or other documentation related to the sale of the potential CERs (including correspondence with multilateral financial institutions or carbon funds); evidence of agreements or negotiations with a DOE for validation services; submission of a new methodology or standardized baseline, or requests for clarification or revision of existing methodologies or standardized baselines to the EB; publication in a newspaper; interviews with DNA; earlier correspondence on the project with the DNA or the secretariat".

11 Current version 07.0, EB 65, Annex 32.

12 https://cdm.unfccc.int/Projects/PriorCDM/notifications/index_html.

With regard to PoAs, the project cycle procedure includes the non-binding provision that "*the coordinating/managing entity may notify to the DNA(s) of the host Party(ies) of the PoA and the secretariat in writing of the intention to seek the CDM status for the PoA, using the [corresponding form] for the purpose of determining the start date of the PoA*". According to the CDM project standard, the start date of a PoA is either "*the date of notification of the intention to seek the CDM status by the coordinating/managing entity to the secretariat and the DNA*" or "*the date of publication of the PoA-DD for global stakeholder consultation*". With regard to CPAs, "*the start date of a CPA is the earliest date at which either the implementation or construction or real action of the CPA begins*" and it shall be confirmed that "*the start date of any proposed CPA is on or after the start date of the PoA*". The only exception to this rule relates to afforestation and reforestation (A/R) PoAs, which allows *"the inclusion of any A/R project activity that started after 1 January 2000 but has not been registered as a CDM project activity as a CPA in an A/R PoA".*[13]

3.1.2. Assessment

The issue of projects obtaining registration as CDM projects without serious consideration of the CDM benefits at the time of the investment decision was especially a concern during the first years of the CDM. The requirement to demonstrate prior consideration was only gradually introduced over time and became generally applicable only in 2007. Also, as pointed out by Schneider (2007), the requirement was also not always followed: only 36% of the projects seeking retroactive crediting provided evidence that the CDM was considered in the decision to proceed with the project and it is reported that relevant documentation has been backdated. It can, therefore, be concluded that for early CDM projects, the demonstration of prior consideration was questionable.

The approach applied as of August 2008 (i.e. for the bulk of projects and generated CERs) requires notification of the prior consideration of the CDM as well as, in situations of delay, evidence of continued interest in the CDM using a form designed for this purpose. This requirement addresses the issue of prior consideration in a more objective and appropriate manner, avoiding the risk of back-dating of company-internal information or subjective claims of prior consideration. In this regard, the rules have improved over time and there is no evident flaw in the current rules and therefore no need for the current practice to be changed.

However, it should be noted that the notification of prior consideration ensures that projects cannot claim CDM registration retroactively, but does not demonstrate whether or not a project is additional. In this regard, this rule does not provide any information on the additionality of projects since both truly additional projects and free riders may apply for the CDM status. This rule is therefore important to exclude projects which did not consider the CDM at all and are therefore clearly not additional, but it is not sufficient for assessing whether a project can be considered additional or not.

With regard to the practical implementation, a period of 180 days for notification of prior consideration can be considered quite generous. While a certain grace period is certainly reasonable due to the administrative process of making the PDDs available for global stakeholder consultation, a period of six months could mean that the project is already quite advanced, which would then call into question whether CDM benefits were actually necessary for the project to proceed. A long grace period could therefore be regarded as allowing retroactive crediting.

The requirements regarding the start date of PoAs and CPAs are sufficiently strict to avoid any project activity that has already started being registered as CPAs under a PoA. The only rule that cannot be considered adequate relates to the inclusion of old A/R activities in a newly registered

[13] Clarification "Start date and crediting period of component project activities under an afforestation and reforestation programme of activities", EB 73, Annex 16.

A/R PoA (see above). For these A/R activities, CDM rules do not require demonstrating prior consideration of the CDM.

3.1.3. Summary of findings

There is no evident flaw in the general design of this rule with the exception of the inclusion of old A/R activities in a newly registered A/R PoA. Also, as outlined above, the time frame for notification of prior consideration appears to be quite generous.

3.1.4. Recommendations for reform of CDM rules

The only rule that needs to be changed relates to the inclusion of old A/R activities in a newly registered A/R PoA (see above). It is therefore recommended that the corresponding rule be withdrawn.

Furthermore, it is recommended that the time frame for notification of prior consideration be shortened in order to reduce the risk that projects apply for the CDM having only learned of the possibility after the project has started. The grace period for notification to the secretariat should therefore be reduced in general, e.g. to a maximum of 30 days after the project start.

3.2. Investment analysis

3.2.1. Overview

The CDM's *additionality tool* requires demonstration that a prospective project is either not financially viable without the CDM (using investment analysis) or that there is at least one barrier preventing the proposed project without the CDM (using barrier analysis). Though both methods are common (and some projects use both), investment analysis is the most widely used, by over three-quarters of all projects and over 90% of the renewable energy (especially hydro and wind) projects that are expected to dominate future CER supplies (Spalding-Fecher & Michaelowa 2013). Investment analysis (or a variation of it) is also used in the *combined tool* and in some CDM baseline and monitoring methodologies that refer neither to the *additionality tool* nor to the *combined tool* for demonstrating additionality.

The additionality tool provides three alternative options for conducting investment analysis:

- For projects with costs but no revenues (other than CERs), a **simple cost analysis** can be used to demonstrate that at least one scenario (other than the project) is less costly. This approach is quite common for a few project types (e.g. projects that capture N_2O from adipic acid plants, or methane from landfills), but it is not common overall.
- The **investment comparison analysis** compares the economic attractiveness of the project without revenues from CERs to other investment alternatives that provide similar outputs or services; this approach is common for just a few project types (e.g. higher-efficiency fossil power), and is not common overall.
- The **benchmark analysis** is used to demonstrate that a proposed project is, without revenues from CERs, economically not attractive (i.e. it does not meet a stated financial benchmark); this approach is, by far, the most common form of investment analysis.

In all cases, investment analysis relies on the premise that, if a project is not a better investment (or less costly) than an alternative or a financial benchmark, then it would not have proceeded but for the existence of the CDM. Exactly how the CDM causes it to proceed, whether through CER revenue or otherwise, does not need to be specified.

The approach to investment analysis has also been refined over time. In particular, in 2008 the CDM EB adopted "Guidelines on the assessment of investment analysis", which aimed to provide further clarity and reduce ambiguity by, for example, clarifying how to calculate the common financial benchmarks net present value (NPV) and internal rate of return (IRR) and suggested ranges for conducting sensitivity analysis in these parameters. In 2011, this guidance was further revised to introduce default values for the expected return on equity for different project types and host countries, which can (but are not required to) be used by project developers as benchmarks for the benchmark analysis.

3.2.2. Assessment

The expected financial performance of a project is clearly one important factor in determining whether or not it will proceed (see further discussion of this in Section 2.3). For example, unless mandated by an (enforced) government policy, there is little reason for projects with no revenue (other than CER values) to proceed, simplifying the assessment of additionality.

For projects that do collect revenue other than CER values, such as by selling electricity, the CDM rules seek to determine whether the project would not have been financially attractive (and therefore not have proceeded) without the CDM. Researchers have raised several critiques of this approach, which we address in this report under two broad themes.

The first is perhaps the most fundamental, and is whether investment analysis is appropriate for investments that may be driven largely by other (non-economic) factors. This critique asserts that many investments in common CDM activities – e.g. power generation – are undertaken for a host of political, social, and strategic reasons that extend beyond simple project-level economics and may not be designed to maximise economic return. Such critics argue that a market-based test such as investment analysis is not applicable in what is largely a non-market environment, perhaps especially so in centrally planned countries such as China (He & Morse 2010). For example, Bogner & Schneider (2011) and Haya & Parekh (2011) have argued that governments have already subsidized and developed large hydroelectricity projects in developing countries well before the CDM, making them financially viable and therefore raising questions about the extent to which investment analysis can credibly determine that they would not proceed but for the incentive provided by the CDM. For investment analysis to function properly – indeed, for any additionality test to function properly – it must be able to demonstrate, with high confidence, that the CDM was the deciding factor for the project investment. For project types that are routinely constructed outside the CDM, including (but not exclusively) for broader economic, energy security, or political reasons, it remains highly difficult to determine with confidence that, in any particular case, a project's financial returns are the reason it is not proceeding and that the financial incentive provided by the CDM is the reason for it proceeding (Dechezleprêtre et al. 2014).

Table 4-5 provides an example of how the decision of selecting a certain fuel (coal, fuel oil or natural gas) may depend on many factors that are not are only insufficiently covered in an investment analysis, such as level of initial investment or flexibility in operation that may lead, for example, in investment in a natural–gas-fired boiler rather than a coal–based one, even though natural gas may be more costly than coal in terms of direct costs.

The second critique is concerned with transparency, subjectivity, and information asymmetry, such as whether project developers provide sufficient and credible information to allow replication of their calculations and justification of their conclusions, as well as the inherent information asymmetry between project developers and those, especially the CDM EB, tasked with reviewing the information. For example, early research found that project developers regularly provided investment analyzes that were opaque, relied on proprietary company information, or were incomplete (Schneider 2009).

This analysis takes a new look at several aspects of this second critique, including:

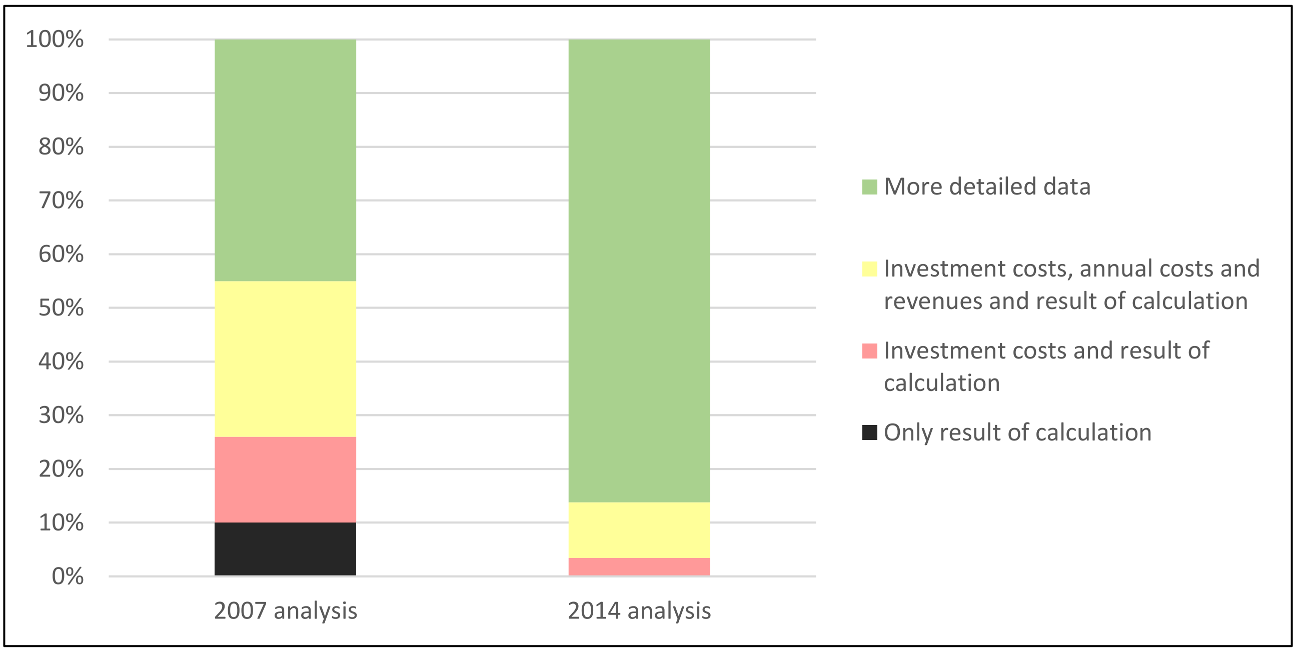
- Transparency, by re-visiting the prior work of Schneider (2009) to gauge how transparently developers conduct the investment analysis.
- Subjectivity and asymmetry, with a new exploration of benchmark rates and CER prices.

These two broad topics are addressed in turn below.

Transparency

To explore transparency in investment analyzes, Figure 3-1 updates the analysis of Schneider (2009) who reviewed a randomly selected group of PDDs for the level of information provided. In our updated analysis, 29 registered projects using the investment analysis were selected at random.[14] Over 90% of the projects selected were registered after 2007, the year of Schneider's prior analysis, so this sample can indicate how practices have changed. In particular, over 80% of the 29 projects in this new analysis provided detailed input data to support their calculations of capital and operating costs and revenues, compared to 2007, when fewer than half did. Furthermore, no projects provided only the result of their calculation in this analysis, with no input data to support their findings. These findings suggest that investment analysis has become more transparent.

Figure 3-1: Level of information provided in PDDs on the investment analysis



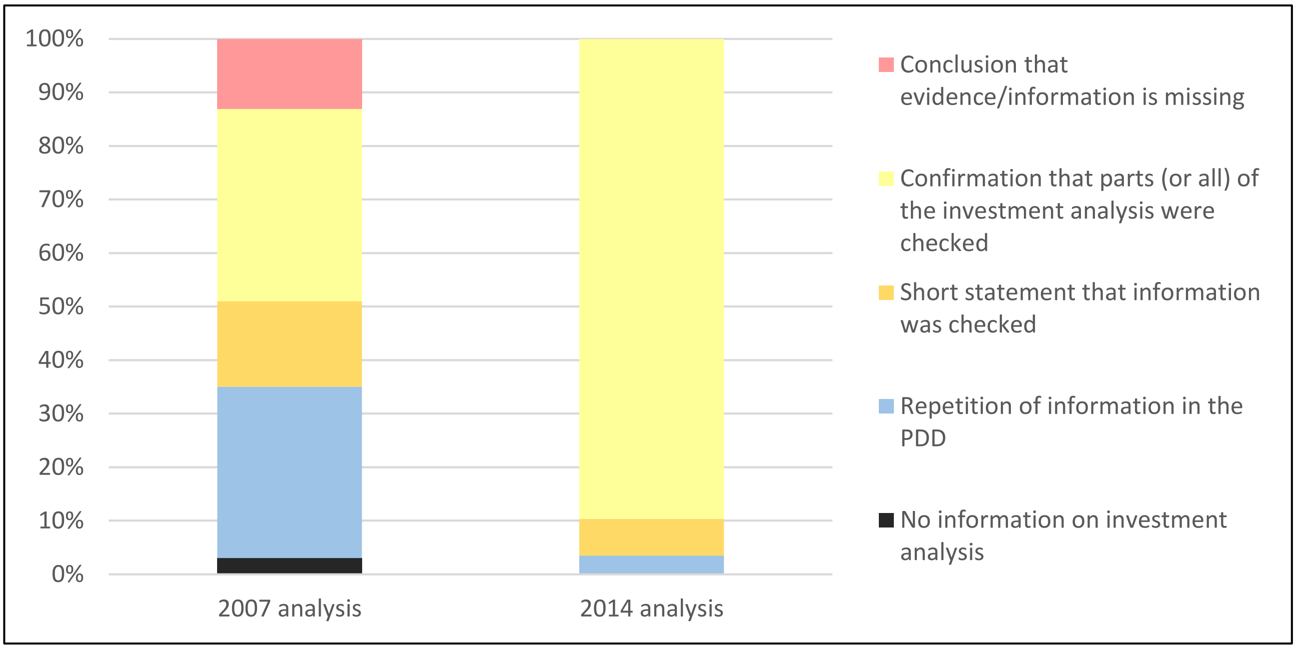
Notes: 2007: n=31, 2014: n=29.
Sources: Schneider (2009), authors' own calculations

Validation reports that review the investment analyzes also appear to have become more thorough. Figure 3-2 also returns to Schneider's prior analysis to update it based on the same randomly selected group of projects as in Figure 3-1. As seen in Figure 3-2, more than 80% of the validation reports confirm that validators checked some or all of the key assumptions of the investment analyzes. The validation reports often review each of several of the most critical investment analy-

[14] According to the sampling design, 30 projects using investment analysis were to be selected. Upon further examination, one of the thirty projects selected, a small-scale, run-of-river hydropower plant, had demonstrated additionality using other methods, as outlined in the "Guidelines for Demonstration Additionality of microscale project activities" and so was not considered in this analysis.

sis inputs and describe that the inputs are reasonable, in many cases citing contract or other documents reviewed to support the choice of inputs.

Figure 3-2: Information in validation reports on the investment analysis



Notes: 2007: n=31, 2014: n=29.
Sources: Schneider (2009), authors' own calculations

Subjectivity and information asymmetry

Despite the findings above, transparency and validator review of the input parameters do not remove subjectivity or choice of alternate input parameters in different contexts. For example, in some cases, project proponents have used different values for key input parameters when submitting applications to financial institutions (Haya 2009), suggesting that the metrics used (and choice of inputs therein) and reliability of such may vary. Indeed, project developers will always have much more information on the project's local conditions – including costs and technical parameters – than will outside parties, whether validators or CDM administrators, and therefore have an incentive to provide biased or inaccurate information to increase the chance of a successful additionality determination and, therefore, the eventual awarding of credits to their project (Gillenwater 2011). This phenomenon is widely referred to as '*information asymmetry'*. As shown above, validators do have more information at their disposal now than in the past, but still lack an objective basis for determining that the investment would not have been undertaken and that inputs provided are the same as they would have been had CDM credits not been sought. Small changes in a number of input parameters – even if individually well within the range of other similar projects (CDM or not), could lead to significant changes in the overall stated financial return of the project. Interestingly, under the CDM, project participants do not need to provide any confirmation that they are submitting truthful information. Some project developers reported that different versions of investment analysis were used for CDM purposes and for the purpose of securing other funding for a project (e.g. loans). Other crediting mechanisms, such as the VCS and CAR, require declaration or attestations from project developers that all information is accurate and presents the truth. To explore further the issue of subjectivity and information asymmetry in input parameters, we take a deeper look at two particular inputs: benchmark rates and CER prices.

Closer examination of benchmark rates

This critique concerns appropriate levels for financial benchmarks (e.g., IRR) (Michaelowa 2009). To explore this question, we reviewed data on IRR benchmarks used by wind, hydro, biomass, and waste gas or heat projects in China, wind and hydro projects in India, and hydropower projects in Vietnam.[15]

Nearly all projects in China use standard, government-issued IRR benchmarks. By far the most common benchmark used is 8%, which is applied for most power projects, and derives from a 2002/2003 Chinese government source, *Interim Rules on Economic Assessment of Electric Engineering Retrofit Projects*. Other common benchmarks based on government rules include 10% for small hydro projects, and 12-13% for waste gas/heat projects.

Table 3-1: Summary of most common benchmark rates used in IRR analysis in Chinese CDM projects

Project type	Common IRR benchmark	Fraction of projects using this benchmark	Source of this benchmark
Wind	8.0%	99%	Government's *Interim Rules on Economic Assessment of Electric Engineering Retrofit Projects* (2002/2003)
Hydro	10.0%	71%	Government's *Economic Evaluation Code for Small Hydropower Projects* (1995)
	8.0%	29%	Government's *Interim Rules on Economic Assessment of Electric Engineering Retrofit Projects* (2002/2003)
Biomass	8.0%	98%	Government's *Interim Rules on Economic Assessment of Electric Engineering Retrofit Projects* (2002/2003)
Waste gas / heat	12.0%	30%	Government's *Economical Assessment and Parameters for Construction Project, 3rd edition* (2006)
	13.0%	17%	Government's *Economical Assessment and Parameters for Construction Project, 3rd edition* (2006)
	18.0%	16%	Conch Cement Company internal WACC

Notes: In this table, and throughout this section, we report IRR benchmarks and values based on analysis of IGES's investment analysis database. We believe that most of the benchmarks, and values reported in the database, are in real terms, based on a review of a small number of PDDs and the assumption in the CDM's Guidelines on the Assessment of Investment Analysis that is conducted in real terms. We make no attempt to identify or convert values in the database that may be in nominal terms.

Sources: IGES 2014, authors' own calculations

Despite the ubiquity of the 8% government-set threshold in China, it is not clear how or why it matches the internal thresholds used by actual project inventors, who may themselves demand returns either higher or lower. (For example, benchmarks for wind power projects in India, where they are determined to a greater extent by investor hurdle rates, are more variable and, on average, higher). For this reason, it is not clear why 8% is the 'correct' benchmark for a test intended to gauge the attractiveness of an investment. Furthermore, it is not clear why common benchmarks used for hydro or waste gas are higher (10% or at least 12%, respectively), and whether these

[15] These project type / country combinations were selected because each of them represents at least 1% of the registered projects in the CDM that use investment analysis (IGES 2012). Though this 1% threshold is arbitrary, it provided us with a basis for focusing the analysis.

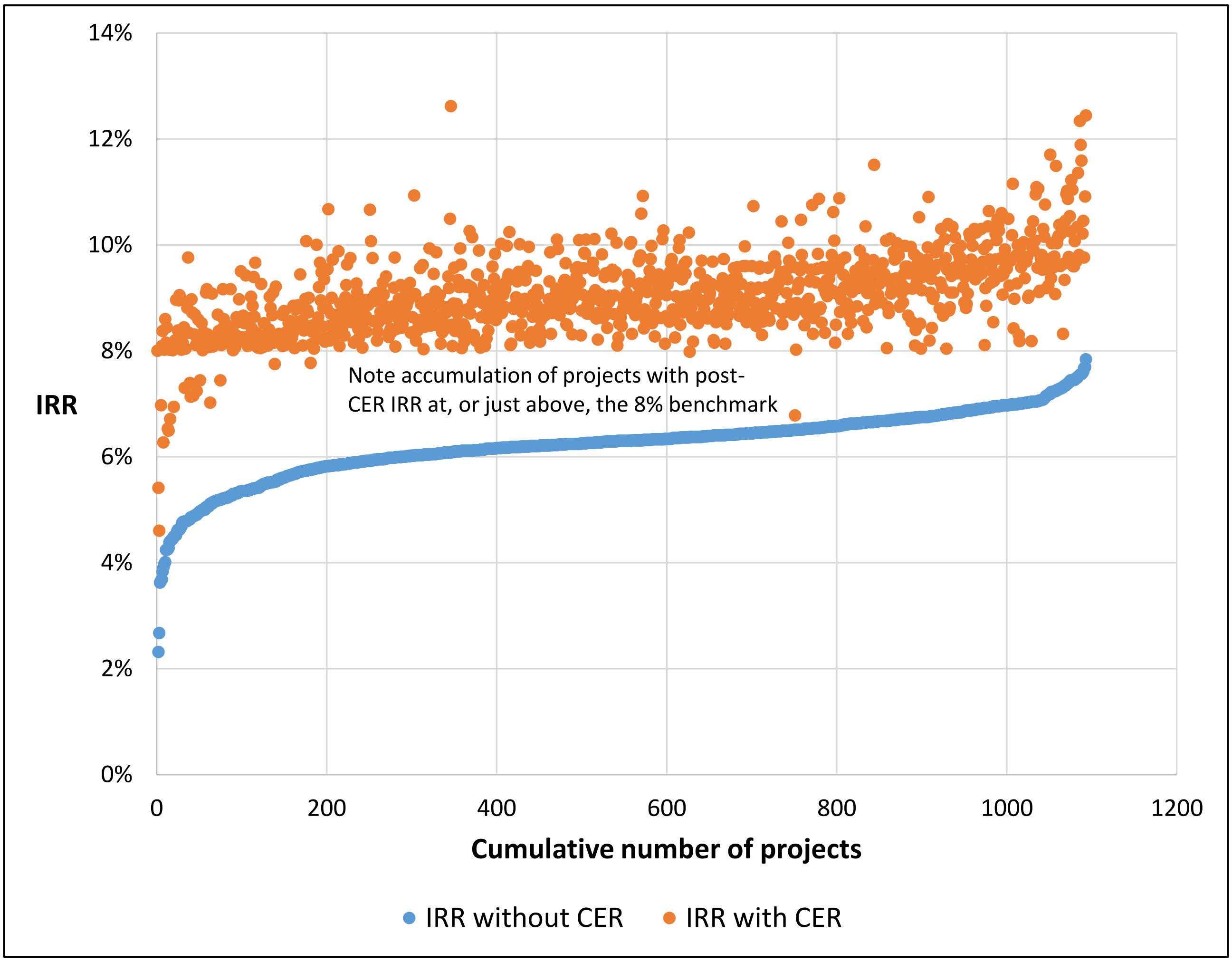
rates accurately capture the risk and expected financial returns in these types of projects. Further analysis of this issue may be warranted, e.g. by comparing it with other sources of equity rates for different investments in China or for similar projects in other countries. A source of such data for projects within China was not immediately known, however.

In principal, the logic of investment analysis is that the project would not have proceeded but for the financial incentive provided by the CDM. That financial incentive is the value of CERs. Many project developers conduct an analysis to show that, at assumed CER prices, the financial return of the project is expected to clear the financial benchmark used. However, this is not actually required by the additionality tool. (In the first versions of additionality, a step 5 'impact of the CDM' was included, which was interpreted by many project developers as an obligation to show that the project is made economically attractive through the CDM. This was later removed).

The above discussion investigated benchmarks used in China, with special attention paid to the widely used 8% benchmark. Because of its ubiquity, this 8% benchmark provides an opportunity to investigate the extent to which CER values indeed bring about expected project returns above this value and therefore, in the logic of the investment analysis, enable the project to proceed. As stated above, though projects are not required to actually show that CER values would push the project above its stated threshold, most do report results of expected return.

The following chart (Figure 3-3) shows the stated IRRs before and after CERs for all wind projects in China that use a benchmark of 8%. As seen in the figure, most of these projects state an IRR without CERs of between 6% and 7%, and an IRR after CER value of 8% to 10%. Note in particular the sharp line at 8%, at which very few projects claim an after-CER IRR of just under 8%, but a large number of projects find a post-CER IRR of just barely more than 8%.

Figure 3-3: Stated IRRs of Chinese wind projects using a benchmark of 8% before and after assumed CER value



Sources: IGES 2014, authors' own calculations

In principle, one explanation for this distribution is that projects in which the 8% threshold is not reached with CER revenues are not implemented, do not apply for CDM registration, and are therefore not represented in this graph. The fact that so many projects just barely meet the 8% threshold (even though they are not required to do so), and so few do not meet it, may instead indicate, however, that project developers are eager to claim that the CER value has allowed the project to clear the benchmark rate.

In contrast to the situation in China where standard government benchmarks are provided, most projects in India use internal, company-specific required rates of return as their IRR benchmarks. However, as in China, the CER value tends to provide a similar increase in expected return (e.g., an increase in IRR of two to three percentage points), just clearing the stated benchmark.

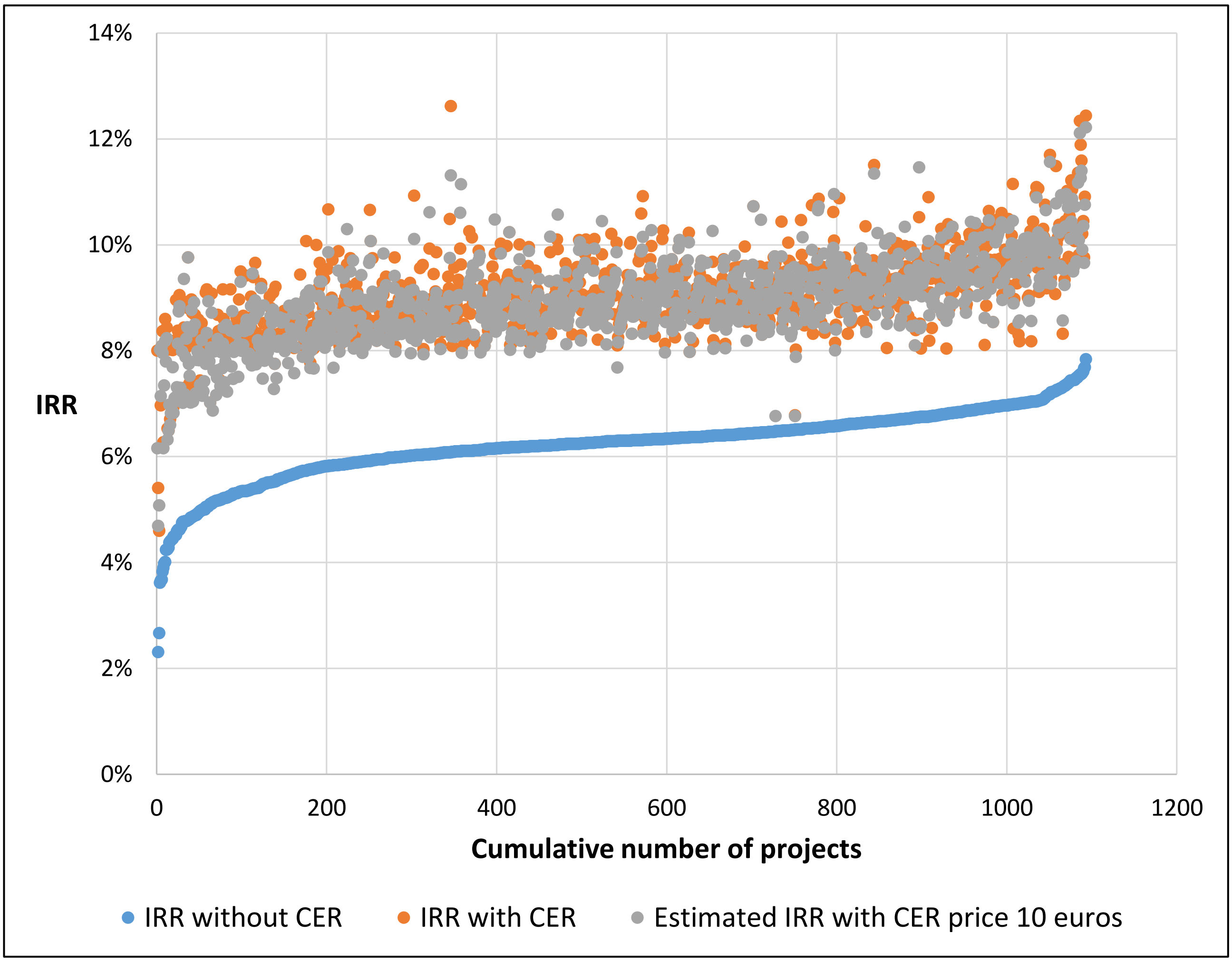
To demonstrate that projects just clear the benchmarks, project developers could select project input parameters so that the benchmark is achieved. These parameters could include CER price, load factor, electricity tariff, or a number of other inputs required in calculating an IRR.

One such parameter that could be adjusted is the expected CER price, which rose consistently through mid-2008, then fell precipitously, and for which forecasts have varied widely since, providing a potentially broad scope for selecting possible future CER prices.

Closer examination of selection of the CER price

To explore the potential effect of the CER price in more detail, Figure 3-4 adjusts the post-CER values stated in the PDDs (as displayed in Figure 3-3) to use a common CER value of €10 for all projects. (€10 is the median value used across all registered projects.) In this example, a large number of projects no longer meet the 8% benchmark. In particular, about 70 projects with pre-CER IRRs of 4% to 6% used CER prices as high as €17 in order to claim they would meet the 8% benchmark. Though this represents just a small share (about 1%) of wind power projects in China, it strongly suggests that input parameters (CER values) have been chosen to achieve the desired result of the 8% government-set IRR benchmark.

Figure 3-4: Estimated IRRs of Chinese wind projects using a benchmark of 8% before and after CER value of €10



Sources: IGES 2014, authors' own calculations

Similar to the situation for Chinese wind power projects discussed above, a number of Indian wind projects that claimed that CER values (median price assumed: €14) would lead them to exceed their benchmark would not have been able to claim that their benchmarks are met if they had used a lower, and more common, CER price of €10. This suggests that, as found in the case of wind power projects in China, project developers in some instances may select CER values that depart from values used by their peers in order to claim that CDM revenues will make the projects financially attractive.

A similar pattern emerges for hydropower projects in Vietnam, where benchmarks (averaging 13.1%) were derived either as the weighted average cost of capital (WACC) or a stated commercial lending rate.[16] Of the projects analyzed[17], over half of the hydro projects would not have met their benchmarks if they had used a CER price of €10 instead of higher prices (median price assumed: €15.5, and as high as €30, in contrast to the remainder of Vietnamese hydro projects with median price assumed of €10). As above, while this is not definitive evidence of gaming, it suggests that project developers tend to invoke higher CER prices than their peers when needed to claim that their projects become economically viable under the CDM.

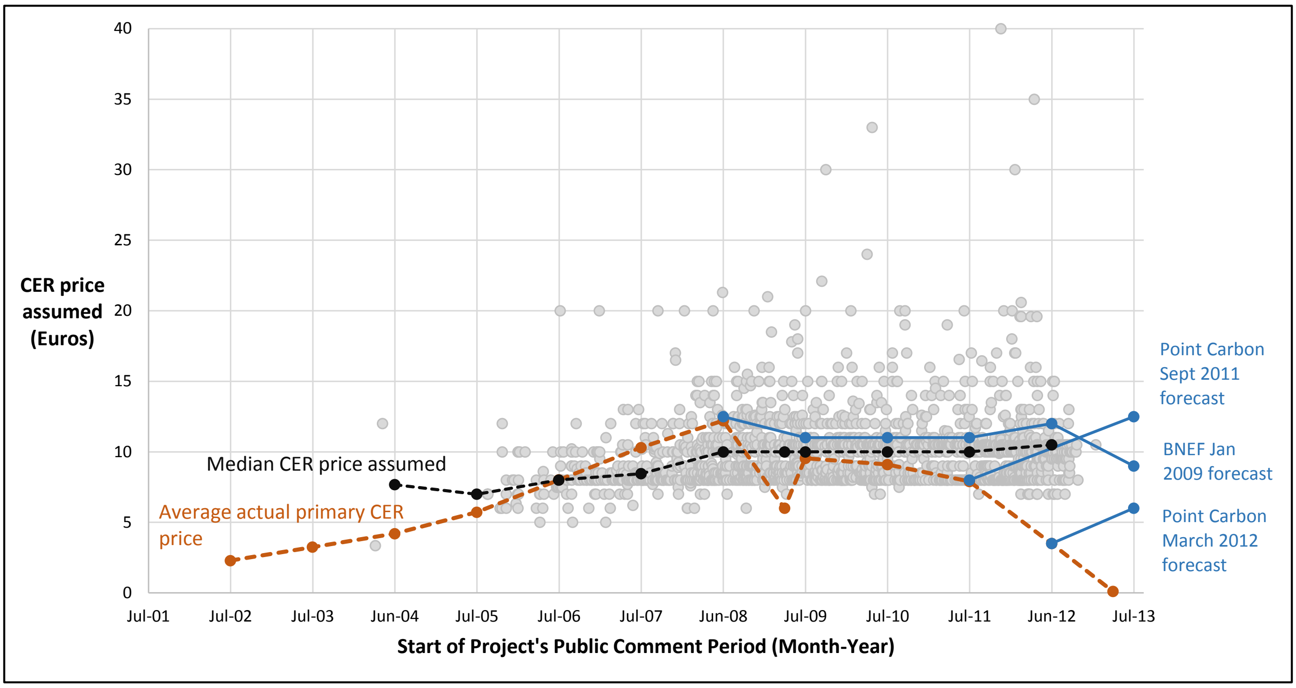
This raises the question of the plausibility of CER prices used by project developers. Looking at all registered projects (Figure 3-5), it appears that the CER prices used by project developers, though highly variable, tended to track then-current primary CER prices, through 2010, when CER prices began a steady decline. Project developers did not then use lower prices, but neither did industry analysts, who forecasted that higher prices would return.

These trends therefore display little evidence that project developers have systematically over- or under-estimated expected CER prices, at least as judged by the median (black line) values. However, the distribution of prices around that median displays a skew wherein a small fraction of projects use very high prices, perhaps because, as shown above, such high prices may be needed to demonstrate that these projects have met benchmarks.

[16] In Vietnam, the median IRR benchmark used by projects in Vietnam was 13.1%, and most benchmarks were derived either as the weighted average cost of capital (WACC) or a stated commercial lending rate. The default expected return on equity for power projects in Vietnam, per the CDM's *Guidelines on the Assessment of Investment Analysis*, is 12.75%; 60% of power projects in Vietnam use an IRR benchmark higher than this rate; 5% have an IRR without a CER value exceeding this.

[17] From the IGES investment analysis database, all hydro projects in Vietnam were selected that reported CER price assumptions in € as well as pre- and post-CER IRR values.

Figure 3-5: CER prices – assumed and estimated



Notes: CER prices assumed by project developers (grey dots) have been relatively consistent with industry forecasts made at the time (blue lines), even though they have been higher than market prices (orange line) since 2008.

Sources: IGES 2014, Point Carbon 2011, Point Carbon 2012

Sensitivity analysis: can it help address subjectivity?

The CDM addresses the subjectivity of input parameters, in part, through the use of sensitivity analysis required in investment analysis. As specified in the *Guidelines on the assessment of investment analysis,* "variables…that constitute more than 20% of either total project costs or total project revenues should be subjected to reasonable variation … and the results of this variation should be presented." However, the guidelines do not require that parameters be varied simultaneously, and few project developers do so. For example, in calculating project IRRs (in the PDDs), no project developer of the 30 randomly selected projects assessed the possibility that more than one of the key input variables could vary simultaneously. Furthermore, nearly all claim that even the standard variations of as much as 10% in the individual parameters are implausible, despite evidence (as presented here) that variation in the input values used is quite common. Accordingly, because the possibility that individual parameters could vary widely is discounted, and the possibility that multiple inputs could vary is not considered, the sensitivity analysis as currently applied is not sufficient to address the subjectivity in these parameters.

3.2.3. Summary of findings

Investment analysis is designed to determine whether a project would be uneconomical or less attractive than an alternative in the absence of the CDM. The premise is that if the project is not economical (most often as compared to a particular investment threshold), it would not have proceeded. From a strictly financial perspective, this may well be the case. However, researchers have pointed out that several types of projects in the CDM – especially large power projects that dominate the CDM pipeline – are pursued for reasons that extend beyond simple financial return, particularly in the largely non-market regulatory environments that are found in some of the largest CDM countries. This may be the most fundamental critique of investment analysis, and yet it is also the most analytically challenging to prove or disprove. Projects may proceed for a variety of factors – economic, strategic, and social – that defy attempts to attribute the viability, or failure, to any one factor. Complicated statistical tests have been proposed – and some statistical research has been attempted – but few compelling approaches have yet emerged.

This research has further explored the issues of information asymmetry, transparency, and subjectivity of input assumptions. Regarding information asymmetry, project developers have considerably more information about their own project than do those – likely including validators – that are charged with reviewing and assessing their additionality. Regarding transparency, this research finds that, since 2007, the transparency of both project design documents and validator assessments has increased markedly, such that the strong majority of projects now include detailed information on input assumptions that their investment analysis could be replicated.

In some cases, there is little reason to question the validity of these input assumptions, as they are based on contract documents (e.g. with equipment providers that would seem to reflect actual prices paid). In other cases, the input assumptions are highly subjective, as in estimates of future fuel prices (e.g. for biomass), electricity tariffs that may be adjusted, or CER prices. In particular, this research has identified dozens of cases in China, India, and Vietnam in which it appears that project developers have used CER prices higher (in some cases, much higher) than their peers in order to claim that the CDM would make their project exceed the chosen financial benchmark. This demonstrates how eager some project developers may be to select input values to give results that would give the appearance of additionality.

3.2.4. Recommendations for reform of CDM rules

As stated above, for an additionality test to function properly, it must be able to demonstrate with high confidence that the CDM was the deciding factor in project implementation. This analysis has demonstrated that the subjective nature of the investment analysis limits its ability to provide that confidence. It is possible that improvements could decrease this subjectivity, such as by applying more complicated tests to assess the true motivations and financial performance of the project. Still, doubts may remain, especially for project types for which the financial impact of CERs is insufficiently large relative to variations in other potential inputs to provide a strong ‘signal-to-noise’ ratio, such as for large power projects. CDM administrators may therefore want to consider whether certain project types, if they cannot be confidently deemed additional by other tests (e.g. barrier analysis, common practice analysis, as in the next sections of this report), might be phased out of the CDM. If the investment analysis continues to be applied, we recommend further improving the guidance to reduce subjectivity. CDM rules could also require formal declarations by the project participants that information is true and accurate. Such declarations may discourage project participants from providing false information, as a violation of such a declaration may have consequences under national legislation. An even stronger form could be a declaration in lieu of an oath.

3.3. First of its kind and common practice analysis

3.3.1. Overview

The CDM uses two approaches to assess additionality based on the market penetration of technologies: the first-of-its-kind approach and the common practice analysis. Under the first-of-its-kind approach, a project is deemed automatically additional if certain conditions apply. The common practice analysis often complements the investment or barrier analysis. It requires an assessment of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and region. It is a credibility check to demonstrate that a project is not common practice in the region or country in which it is implemented. The common practice analysis can also be used to demonstrate that the baseline technology or practice is frequently implemented and is hence a realistic scenario. The common practice analysis is only relevant for large-scale projects. Small-scale projects are entitled to use simplified modalities and procedures for small-scale CDM project activities, which do not require common practice analysis.

The first-of-its-kind approach was initially applied as part of the barrier analysis; it was sometimes also referred to as the barrier of lack of ‘prevailing practice’. In 2011, the EB adopted guidelines specifying how first-of-its-kind should be demonstrated. The guidelines were further revised in 2012 and reclassified as a tool in 2015.[18] Showing that a project is the first-of-its-kind is the first step in the additionality tool and combined tool, which stipulate that if a project is the first-of-its-kind, it is considered additional. The steps to be followed for demonstrating first-of-its-kind are further specified in the corresponding guidelines and, since 2015, the methodological tool. According to version 03.0 of the tool, a project activity is “first of its kind in the applicable geographical area” if

- “the project is the first in the applicable geographical area that applies a technology that is different from technologies that are implemented by any other project” with the same output and that “have started commercial operation in the applicable geographical area before” the PDD “is published for global stakeholder consultation or before the start date of the proposed project activity, whichever is earlier”, if
- “the project implements one or more of the measures” and
- “the project participants selected a crediting period for the project activity that is “a maximum of 10 years with no option of renewal”.

The common practice test was first introduced in the additionality tool in 2004 to complement the investment and barrier analyzes, as a safeguard to ensure the environmental integrity of the CDM. In a first step, other previous or current projects which are similar to the project activity were analyzed. Projects were considered similar “if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc.” Other CDM projects were excluded from this analysis. In case similar activities were identified, it was necessary to justify why these exist, while the project activity is considered to be financially unattractive or as facing barriers. ‘Essential distinctions’ had to be identified which may for instance be due to the fact that new barriers have arisen or promotional policies have ended.

For both the first-of-its-kind approach and the common practice analysis, the key issues are defining what is regarded as a comparable technology, what the appropriate geographical scale is and what threshold should be used for a technology to be regarded as first-of-its-kind or common practice. Critics pointed out that no clear definitions of when a project activity should be regarded as common practice were given in the early versions of the additionality tool (Schneider 2009). Another criticism was that the common practice test allows project developers to claim that a frequently implemented project type is not deemed common practice if they can justify ‘essential distinctions’ from other projects. Yet the key terms ‘similar’ and ‘essentially distinct’ were defined so vaguely that any project could be argued to be not common practice, simply by defining ‘similar’ very narrowly or ‘distinct’ very broadly (Schneider 2009; Spalding-Fecher et al. 2012).

The requirements for the common practice analysis in the additionality tool remained largely unchanged until September 2011 when the “Guidelines on Common Practice” were introduced, incorporating elements from the additionality tool and providing additional guidance[19]. In parallel to the revision of the “Guidelines on first-of-its-kind”, the “Guidelines on Common Practice” were further revised in 2012 and reclassified as a tool in 2015.

[18] Methodological tool. Additionality of first-of-its-kind project activities (version 03.0).
[19] The new requirements of the Guidelines on Common Practice were then also incorporated in the additionality tool in the same year.

Both guidelines or tools are applicable to four GHG reduction activities, namely, "fuel and feedstock switch, switch of technology with or without change of energy source (including energy efficiency improvement), methane destruction" and "methane formation avoidance"[20]. Both also use similar approaches for defining similar or different technologies and the appropriate geographical area.

In the 2011 version of the common practice guidelines, the first step was to calculate the applicable output range as +/-50% of the capacity of the project activity. In the next step, all existing plants in the geographical area within this capacity range needed to be identified (with the exception of registered CDM projects). The default applicable geographical area was the entire host country. If the technology was not country-specific, the geographical area should be extended to other countries. If projects differ significantly between locations, the geographical area could also be smaller than the host country. In the next step, among the identified projects, those with different technologies from the project activity were identified. A technology was considered different if it has a different energy source/fuel, feedstock, installation size (micro, small, large), investment climate at the time of the investment decision[21] or other features.[22] Eventually, if the share of plants using similar technology as in the project activity in all plants with the same capacity as the project activity is greater than 20% and if the absolute number of projects using a similar technology is larger than three, then the project activity is considered common practice.

In revising the Guidelines on Common Practice in September 2012, the rules and definitions were further clarified. It is now mandatory to provide a justification for using a geographical area smaller than the entire host country (e.g. province, region). The reference to extending the geographical area was removed from the guidelines. The exclusion of CDM activities was broadened to include registered projects, those requesting registration and those at validation. Furthermore, several definitions and the step-wise approach were better explained (without change in substance). Minor changes to the common practice analysis were made in subsequent versions of the additionality tool.

The definition of different technologies in the first-of-its-kind approach corresponds to the common practice analysis, with the exception that investment climate at the time of the investment decision and other features are not included.

3.3.2. Assessment

The general strength of using market penetration approaches for assessing additionality is that they do not assess the motivation or intent of project developers, but provide a more objective approach to evaluating additionality, based on the extent to which the project activity is already being implemented in the host country or region (Schneider 2009).

The initial criticism of the lack of clear definitions of similar projects and essential distinctions for common practice was addressed by the introduction and further refinement of the common practice guidelines, which clearly outline steps to follow and provide a definition of terms for a common understanding between project developers. Especially, the introduction of a threshold for common practice (20% and at least three similar projects) constitutes a significant improvement since it requires a quantitative assessment against a clear threshold. Clarity about the rules related to common practice analysis has therefore improved considerably over time. Also, from the sampled projects, it can be concluded that the introduction of the common practice guidelines has generally led to more detailed and better structured PDDs.

[20] For other types of GHG reduction activities, the more general rules of the additionality tool continue to apply.
[21] "Inter alia, access to technology, subsidies or other financial flows, promotional policies, legal regulations."
[22] Such as a difference in unit cost of output by at least 20%.

However, several unresolved issues still exist. In the following, different aspects of the common practice analysis and the first-of-its-kind approach are discussed and assessed. The assessment is based on an analysis of the common practice provisions and on the findings of an empirical evaluation of 30 representatively selected projects (i.e. the review of PDDs and validation reports) (Section 2.2).[23]

When defining similar projects in the common practice tool, the applicable output range is defined as “+/-50% of the design output or capacity of the proposed project activity”. This definition does not always reflect the scales of a technology, between which meaningful technological differences occur. For instance, in the case of a power plant with a size of 400 MW, power plants between 200 MW and 600 MW would need to be considered in the analysis. However, there may be smaller (e.g. 100 MW) or larger (e.g. 800 MW) power plants which still feature similar technical, economic characteristics (e.g. efficiency), a similar regulatory environment, or which are used in a similar manner (e.g. provision of electricity to the public grid). At the same time, a small power plant (e.g. 5 MW), may be significantly different in terms of technology or use. Also, when several plants are grouped to form a project (e.g. wind farm consisting of several wind generators), an output of +/-50% may be misleading. For instance, for a wind farm with 20 wind generators of 1 MW capacity, the output range would be 10 to 30 MW. However, a smaller wind farm with only 10 wind generators of 1 MW capacity has similar characteristics since the wind generator is identical. For wind power, the test may provide more meaningful results if there was no scale at all since wind parks are usually composed of different wind generators of the same size. However, small internal combustion engines may well differ, from a technological perspective, from a large combined cycle power plant. In conclusion, the definition in the common practice guidelines (+/- 50%) does not allow for a meaningful classification of scale for different technology types. This definition can therefore be considered arbitrary and may lead to the erroneous exclusion of similar plants from the analysis. In contrast to the common practice tool, the first-of-its-kind tool does not use an output range to define similar technologies. This approach seems more appropriate.

When identifying similar projects, the common practice tool excludes CDM projects (registered, submitted for registration or undergoing validation) from the analysis. In the empirical analysis, of the 30 sampled projects, only three identified similar non-CDM projects. All other projects only identified projects under the CDM. A commonly used rationale (i.e. used by 9 of the 30 projects) is that, because all other comparable facilities are either CDM projects or are awaiting registration as CDM projects, the proposed project would also be non-viable without the CDM (i.e. not common practice). However, it could be argued that the general viability of projects is assessed as part of the barriers and/or investment analyzes and should therefore not be used as a pre-emptive argument for excluding CDM projects from the common practice analysis. The exclusion of CDM projects from the common practice analysis is particularly problematic if most or all new facilities in a sector use the CDM. For example, if all new wind power plants in a country register under the CDM, wind power could never become common practice, even if it reached a market share of more than 50% and was highly economically attractive. In contrast to the common practice tool, the first-of-its-kind tool does not have provisions to exclude CDM projects, which suggests that all existing projects, including CDM projects, are considered.

23 Of the 30 projects sampled for the evaluation of the common practice analysis, the majority stem from China (20 projects), followed by India (3), Egypt (2), Pakistan (2), Brazil (1), Nicaragua (1) and Israel (1). Ten projects were registered before 2010, eight in the 2010-2011 period and twelve after 2011. Technology types in the sample are wind power (17 projects), hydropower (5), industrial projects such as coal mine methane utilisation or waste heat recovery (3), waste projects such as landfill gas capture (4) and other renewable energies such as biomass (1). Most projects (28 of 30) are classified as large-scale. Although the sampled two small-scale projects are not required to conduct a common practice analysis, some information on common practice was given in the corresponding PDDs.

The common practice tool and the first-of-its-kind tool use the same definition of the geographical area, which should be the entire host country, unless justification can be provided for a smaller geographical area. In the common practice analysis sample, 24 of 30 projects limited the applicable geographical area to a specific area smaller than the host country (such as province, region, state, municipality, etc.). All sampled wind projects from China (11)[24] and from India (3) selected an area smaller than the host country as the applicable geographical area. The most commonly used justification in the corresponding PDDs for limiting the geographical area is that investment conditions, especially in terms of electricity tariffs, available resources and labour costs, differ from province to province, making provincial/state level comparison necessary.

At first sight, this appears to be plausible since China and India are large countries with regions/states being important players in infrastructure development. Notwithstanding this, the size of the country and the political structure may not be sufficient to justify the choice of the regional/state level. In China, a nationwide feed-in tariff for wind power generation was introduced in 2009, establishing four different tariff categories, ranging from 0.51 CNY/kWh (0.08 USD/kWh) to 0.61 CNY/kWh (0.10 USD/kWh), depending on the region's wind resources (International Renewable Energy Agency 2012). For projects in India, the Electricity Act of 2003 and the resulting new tariff regulations were cited as the cause of different investment climates in various states. In fact, for wind power, the tariff varies based on local wind resources. Four bands of wind power density in W/m^2 determine the level of the feed-in tariff (International Energy Agency 2012). This means that the feed-in tariff may differ even between project locations in the same province if these feature different wind conditions. Therefore, the fact that there are different feed-in tariffs between provinces alone does not explain fundamentally different investment conditions in the different regions, as claimed in many PDDs, but rather only accounts for locally different wind resources, while the general support scheme is national[25]. Based on these considerations, the rationale used by many projects for limiting the geographical area to a level below the entire country seems questionable. It can also be problematic to consider only the host country as the geographical area. If no or only a very few plants providing the same service exist in the host country, market penetration approaches do not give reasonable results. For example, the first aluminium plant in a country would always automatically be deemed additional, even if it used a technology that is clearly business-as-usual.

While the introduction of the common practice guidelines aimed to address the criticism of a vague definition of what constitutes 'different' technologies, several concerns remain. The possibility of defining a technology "as being different if there is a difference with regard to energy source/fuel, feed stock, installation size (micro, small, large), investment climate at the time of the investment decision (including, "inter alia, access to technology, subsidies or other financial flows, promotional policies, legal regulations") or other features (such as difference in unit cost of output by at least 20%)" still allows for significant possibilities to claim that rather similar projects are very different. This allows for the project to be defined rather narrowly and other plants very broadly, so that the threshold of 20% is not reached. With regard to the installation size, the same issue as for the output range (above) applies. Also, the criterion 'energy source/fuel' may be misleading. For instance, if a country has been using light fuel oil as a basis for its power plants, a switch to natural gas constitutes a different fuel, but does not explain a significant difference since the same generation technology can be used for both fuels. The same holds true for different solid fuels. Finally, 'other features' is a very broad term allowing for arbitrary interpretations. For example, a difference in unit cost of output does not constitute a plausible difference per se[26]. For instance, higher unit costs

[24] Also all other Chinese (non-wind) projects included in the sample use a sub-national geographical area with a similar rationale as that for wind projects.

[25] A differentiation of the feed-in tariff depending on local wind resources is common practice in other countries as well.

[26] Two sampled hydro projects used this rationale.

may be required for technical or other reasons and may be compensated for by higher yields[27]. Also, according to this interpretation, a proposed CDM project with *lower* unit costs would be considered different from projects already implemented without CDM, even though it is more profitable than other projects. Although in some cases, 'differences' may be well justified (e.g. by explaining that the investment climate was significantly different due to a change from a state-controlled to a more private investment-oriented power market), overall, the review of arguments presented in the sampled PDDs indicate that the term 'different' allows for significant room for interpretation.

The threshold of 20% market diffusion in the common practice tool cannot be considered robust if applied to all technologies and sectors. The stringency of the 20% is highly dependent on the number of technologies in a sector. In a sector with only two technologies, both available technologies could easily exceed the threshold, whereas none of the technologies may ever reach the 20% threshold in sectors with many different technologies. For instance, in a country with several fuels and technologies available for power generation (e.g. natural gas, coal, wind, hydro, biomass, PV), a low market diffusion may still constitute common practice due to the abundance of options and due to the (potentially) limited potential of some technologies. For instance, hydro electricity generation may constitute only 5% of overall electricity generation. Nevertheless, hydropower could still be considered common practice due to the fact that hydro resources are limited and most of the resources have already been exploited. In contrast, in a sector in which there are only a few technologies (e.g. for a certain industrial process) a market diffusion of 20% may constitute a reasonable value for determining common practice. Also, even though a technology may not be considered common practice considering all existing plants in a sector (i.e. considering the market saturation), it may be common practice considering the recent trend (i.e. considering the market share in a certain year)[28]. For instance, electricity generation from wind may constitute only a small share of the overall electricity generation in a country (e.g. 1%). However, capacity additions in recent years may constitute a significant share of overall new capacity built. In the former case, wind power would not be considered common practice, whereas in the latter, trend-oriented, perspective wind power would constitute common practice. This issue is especially relevant in the case of long-lived capital stock such as in the power sector (Kartha et al. 2005). Similarly, the provision that at least three plants with a similar technology must have been constructed to consider a project common practice may not be appropriate in all situations. For example, if only four plants exist in a country and three use the same technology, thus constituting a market share of 75%, the construction of a fifth plant with the same technology would still not be regarded as common practice. In conclusion, a one-fits-all value as threshold for market diffusion cannot be considered appropriate.

With regard to the quality of evidence used for the demonstration that a project is not common practice, almost all PDDs provided anecdotal evidence to support their claims. Commonly made statements are that there is no evidence to suggest that a similar project has been, is being or will be implemented in this area and that all other projects use CDM financing as well. To support these claims, publicly available external documents such as energy statistics were used in the majority of projects (20 of 30 projects). Yet, these public documents do not provide information about different investment climates in terms of labour costs, available resources and feed-in tariffs.

As regards the validation of common practice, in 21 of 30 sampled projects, the DOE reviewed documents such as the World Bank website or energy statistics. Other means of validation were conducting interviews with stakeholders such as personnel with knowledge of the project design and implementation, local residents and officials.[29] However, the DOEs did not evaluate claims

[27] E.g. higher units costs may be required for certain equipment for small hydro in a mountainous area, which may be compensated for by higher yields due to a higher head of water.

[28] See Kartha/Lazarus/LeFranc (2005) for a definition of market saturation vs. market share.

[29] There is no further information available in the PDDs on the content of the interviews with the stakeholders.

made in the PDDs about different investment climates. In nine cases, the DOE in its validation report just repeated the claims made by the PDD.

3.3.3. Summary of findings

Overall, clarity about the rules related to first-of-its-kind and common practice analysis have improved considerably over time. In addition, from the sampled projects it can be concluded that the introduction of the common practice guidelines has generally led to more detailed and better structured PDDs. However, several flaws remain:

- The definition of the output range in the common practice tool is arbitrary and not linked to actual differences in scale of technologies or use.
- The exclusion of CDM projects from the analysis is questionable in a market situation in which most projects are implemented as CDM projects and significant technological changes and cost reductions occur.
- The rationale for limiting the geographical area to a level below the entire country is questionable. In some instances, limiting the geographical area to the host country can be problematic.
- The definition of a project as ‘different’ in the current common practice guidelines is still too vague and corresponding rules still leave significant room for interpretation.
- The share of 20% market diffusion and absolute number of three similar projects, across all sectors, cannot be considered robust since the appropriateness of these values depends on the number of available technologies in the sector. Additionally, the result of the common practice analysis is highly sensitive to whether all plants of a sector are considered or whether the recent trend (new plants built) is considered. This is especially relevant for sectors with long-lived capital stock.
- Generally, evidence used for the common practice analysis was not adequate in the sampled projects since relevant information for the determination of common practice (e.g. on different investment climates, available resources or feed-in tariffs) was not provided in the PDDs. Also, the validation by DOEs was not adequate in the sampled projects since claims on investment climates were not evaluated and since in several cases the DOE only repeated the claims made by the project participants.

3.3.4. Recommendations for reform of CDM rules

In general, the first-of-its-kind approach and the common practice analysis can be considered more objective approaches than the barrier or investment analysis due to the fact that information on the sector as a whole is taken into account rather than specific information of a project only. It reduces the information asymmetry inherent in the investment and barrier analysis. In this regard, expanding the use of market penetration approaches could be a reasonable approach to assessing additionality more objectively. However, the presented analysis shows that the way in which first-of-its-kind and common practice are currently assessed needs to be reformed in order to provide a reasonable means of demonstrating additionality. In the following, several recommendations are made for the reform of the current rules.

We identified several issues with the approach of using the same generic approach in the context of rather different sectors or project types. We therefore recommend abandoning this ‘one-size-fits-all’ approach and introducing specific approaches for specific project types, which adequately reflect the circumstances of the sector, in particular with regard to the definition of what is considered a different technology and the threshold used to define common practice. A practical means of implementing this is including specific guidance in each methodology.

- Due to the inherently vague concept of 'different' technologies, it is recommended that the common practice rules are revised in such a way that methodologies or overarching guidance provide clearer guidance on how to support the claim of a 'different' technology including the evidence required (including evidence to demonstrate credible differences in the investment climate). Corresponding provisions in the VVS should also be amended in such a way to provide more specific guidance on how DOEs should assess the claim of 'essential distinctions' for different projects types. With regard to the above-mentioned arbitrary definition of the applicable output range, it is recommended that the common practice guidelines are revised in such a way to provide general guidance on how meaningful differences according to scale can be identified for different technologies. More specific guidance on how to define a range of capacity/output should then be defined in the corresponding methodology. In the absence of any definition of capacity/output range in the methodologies, the whole spectrum of plants or activities (from very small to very large) should be covered by the analysis.

- With regard to the exclusion of CDM projects from the common practice analysis, the rules should be amended in such a way that all CDM projects are to be included in the analysis as a general rule, unless specified otherwise by the methodology. Methodologies could specify that CDM projects are excluded to a certain extent and then gradually introduce them in the analysis. This is especially relevant if all projects of a certain technology use the CDM. As Schneider (2009) points out "other CDM projects could be included in the common practice analysis after a certain period or after a specific number of CDM projects have been implemented". Another criterion for inclusion of CDM could be their market penetration. (International Rivers 2011) suggest that "after 3 years of full operation, a CDM project should be included in the common practice analysis". Furthermore, a "list of project types that are not eligible for the CDM because they are common practice" (ibid.) (negative list) could also be helpful in this regard.

- Due to our finding that the selection of an area below the host country level as the applicable geographical area is a questionable assumption, it is recommended that the rules be revised to define the appropriate geographical area in the context of the specific circumstances, such as the number of projects or installations in the host country. A level below the host country level should not be used.

- The threshold for common practice should be defined depending on the type of technology and sector. Corresponding guidance should be provided in the methodologies. In sectors with long-lived capital stock (e.g. power sector), the common practice analysis could consider two different perspectives: a) common practice in the sector (e.g. power sector) as a whole (market saturation) and b) common practice in more recent investments (market share) (i.e. similar to the operating and build margin approach for projects displacing electricity). If common practice is established according to at least one of these perspectives, the project should be considered common practice. Since data availability for determining market diffusion may not be sufficient in each country and in order to ensure consistency in determining market diffusion, efforts (e.g. multilateral) for collecting this data and for providing this information to project developers could be helpful. Several global datasets already exist (e.g. UNEP DTU 2014, statistics by the World Bank, sectoral statistics, Platts database on power plants or cement statistics by Cembureau), which could be used to estimate market diffusion in different countries in a consistent manner. An extensive discussion of the usefulness of market penetration for establishing common practice for certain projects types is included in (Kartha et al. 2005).

Due to the fact that several DOEs repeated the claims made by the project participants without documenting the way in which they actually assessed the appropriateness of the claims, we recommend strengthening efforts to ensure that all DOEs effectively comply with the reporting requirements related to the common practice analysis outlined in the VVS. For this purpose, no change in rules has to be applied, but the accreditation system may need to be strengthened to ensure compliance of all DOEs with applicable CDM requirements.

Another option for improving the analysis of common practice is to consider the overall potential available in a country. For instance, a small share of hydro in overall electricity generation may, on the one hand, be due to barriers, risks or economic unfeasibility of hydro construction (hydro electricity generation would therefore not be common practice). On the other hand, the small share of electricity generation from hydro may be due to the very limited hydro potential in the country. Most of the (small) potential may already have been exploited. Any additional hydro capacity could then be considered common practice since it has been exploited before. However, this approach would bring about the problem of defining ways to establish the potential (e.g. technical vs. economic potential, etc.), and the practicalities and transaction costs of evaluating this for many different technologies.

Furthermore, the common practice analysis could "be the first step in the additionality tool rather than the last" (International Rivers 2011). This way, instead of using often vague arguments for establishing common practice *after* the investment analysis, project developers would need to discuss common practice explicitly at the beginning of the analysis.

3.4. Barrier analysis

3.4.1. Overview

Historically, barrier analysis has been used as an important alternative or complement to the investment analysis analyzed above in Section 3.2. The barrier analysis is used to demonstrate that a project faces barriers that impede the project's implementation in the absence of the incentives from the CDM. It is applicable to both small- and large-scale CDM projects:

Small-scale projects

According to Attachment A to Appendix B to Annex II of 4/CMP.1 the following barriers may be considered for small-scale projects:

- **Investment barrier**: a financially more viable alternative to the project activity would have led to higher emissions; this includes "the application of investment comparison analysis using a relevant financial indicator, application of a benchmark analysis or a simple cost analysis".[30] In essence, this barrier allows an investment analysis to be conducted, as described in Section 3.2, but without providing any guidance on how the investment analysis should be conducted. In practice, however, it appears that guidance for investment analysis for large-scale projects (e.g. justification of benchmark IRR or sensitivity analysis) is, in most cases, also applied to small-scale projects.

- **Access-to-finance barrier**: the project activity could not access appropriate capital without consideration of the CDM revenues;

[30] See "Non-binding best practice examples to demonstrate additionality for small-scale projects" (EB 35, Annex 34).

- **Technological barrier**: a less technologically advanced alternative to the project activity involves lower risks due to the performance uncertainty or low market share of the new technology adopted for the project activity and so would have led to higher emissions;
- Barrier due to **prevailing practice**: prevailing practice or existing regulatory or policy requirements would have led to implementation of a technology with higher emissions;
- **Other barriers** such as institutional barriers or limited information, managerial resources, organisational capacity, or capacity to absorb new technologies.

Large-scale projects

In large-scale projects, the barrier analysis is part of the additionality tool and the combined tool. It is applied in two steps:

1. Identify barriers that would prevent the implementation of the proposed CDM project activity. Here, the eligible barriers are similar to the barriers relevant for small-scale projects, with the following differences:
    - The 'investment barrier' of the small-scale guidance is, in the large-scale guidance, referred to as 'investment analysis' (Section 3.2); a separate option for demonstrating additionality besides 'barrier analysis';
    - The 'access-to-finance barriers' of the small-scale guidance is called 'investment barriers' in the large-scale guidance; and
    - 'prevailing practice' of the small-scale guidance is, in the large-scale guidance, usually a mandatory additional step termed 'common practice analysis' that is required but is not sufficient in itself to prove additionality.
2. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity).

Another important requirement of the two tools is the following: "If the CDM does not alleviate the identified barriers that prevent the proposed project activity from occurring, then the project activity is not additional."

If these steps are satisfied, the project is potentially additional (pending passing of the common practice analysis).

In late 2009 (EB50), the CDM EB adopted the "Guidelines for objective demonstration and assessment of barriers" with a view to improving the objectivity of the barrier analysis. The document provides guidance on the objective demonstration of different types of barriers. For instance, it requires that "barriers that can be mitigated by additional financial means can be quantified and represented as costs and should not be identified as a barrier for implementation of project while conducting the barrier analysis, but rather should be considered in the framework of investment analysis" (Guideline 4 in EB50 A13).

In addition, methodologies may – instead of using one of the tools – provide their own combination of steps from the tools.

3.4.2. Assessment

The concept of barriers preventing investments and mitigation activities is an important element of the research and discussion on technology diffusion and low carbon pathways. From this, it seems reasonable that the additionality test could also take barriers into account and not only be based on investment analysis. However, the barrier analysis faces multiple challenges in practice that strongly limit its usefulness in the context of the CDM.

Objectivity in barrier analysis

In earlier phases of the CDM, the claim for barriers preventing the implementation of projects was often based on anecdotal evidence, and it was very difficult to provide objective proof of why a barrier is sufficient to "prevent the implementation" (Schneider 2009). In practice, the concept of barriers per se as proof for additionality is problematic, as all investment projects in all countries faces some sort of barriers to its implementation, be they financial, technical or other. In earlier CDM projects, it was sufficient for PDD consultants to state barriers without providing objective and verifiable evidence that they actually *prevent* the implementation of the project. This led to some market participants claiming that with good PDD consultants you could have any project registered based on barriers.

Guidance on objective barriers

In late 2009 (EB50), these problems with barrier analysis led to the adoption of the "Guidelines for objective demonstration and assessment of barriers" by the CDM EB (Section 3.4.1). With their requirement to monetize barriers, the guidelines aim to assess the role of barriers in preventing the implementation of projects in a more transparent way. The monetization of barriers and their inclusion in the investment analysis provide a framework that allows an objective balancing of higher barriers and associated costs with the need for higher revenues. This may be one of the reasons why investment analysis (with or without monetized barriers) has largely replaced the use of the barrier analysis without application of investment analysis in demonstrating additionality (see below).

How much alleviation is necessary to overcome a barrier?

Another weakness of the barrier analysis lies in the application of the requirement to demonstrate that the CDM "alleviates the identified barriers that prevent the proposed project activity from occurring". The fulfilment of this requirement was not often (explicitly) provided in PDDs nor checked by DOEs. Moreover, the tools do not require that the degree of 'alleviation' should be at least comparable to the strengths of the barrier under consideration. To demonstrate the viability of the project with the CDM, one would need to make the case as to why, for example, €x of CER revenues are sufficient to alleviate the risk of damage to a wind farm due to severe sand storms.

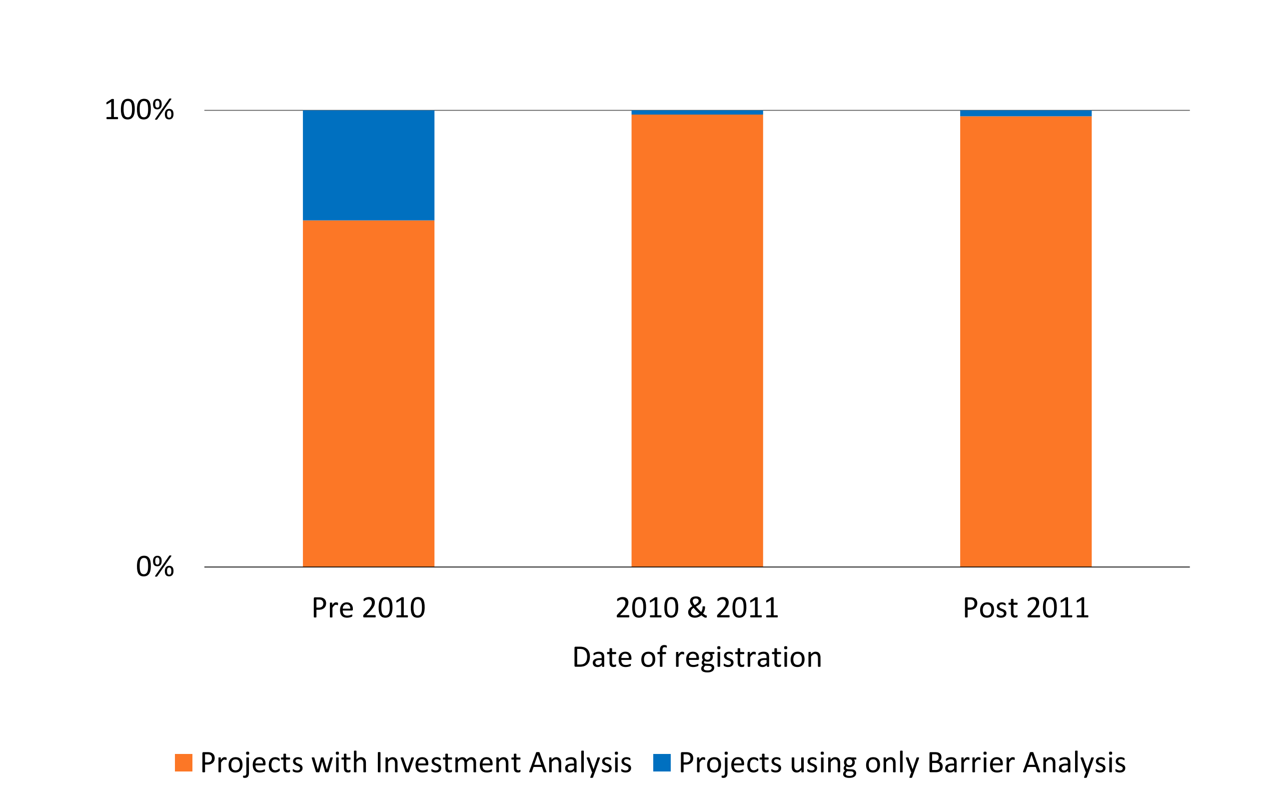
Also with regard to this requirement, the Guidelines provide greater specificity: "Demonstrate in an objective way how the CDM alleviates each of the identified barriers to a level that the project is not prevented anymore from occurring by any of the barriers" (Guideline 2 in EB50 A13).

The vanishing role of barrier analysis in the CDM

The role of barrier analysis in demonstrating additionality in the CDM has been dramatically reduced from 2010 onwards (Figure 3-6). While in the period before 2010 approx. 24% of registered projects used the barrier analysis *without applying an investment analysis in parallel*, this share was reduced to approx. 1-2% of registered projects from 2010 onwards. Since then, the barrier analysis plays a certain role in reinforcing the additionality argument made in the investment analysis, but has largely lost its role as the main approach for demonstrating additionality.

This development might be explained by the introduction of the guidelines for objective demonstration and assessment of barriers.

Figure 3-6: Share of projects using the barrier analysis without applying the investment analysis in total projects



Notes: Own research based on a representative sample of PDDs from 30 stratified and randomly sampled projects that were labelled Investment Analysis option 'none' by the IGES (2014) database revealed that a certain percentage of these PDDs used an approach that in essence follows the Investment Analysis approach of the additionality tool, but was labelled 'Barrier Analysis'. The confusion in terminology was most prominent in small-scale project PDDs, which have the option to demonstrate 'financial barriers' which includes and is often an Investment Analysis. In the representative sample, the fraction of PDDs using actually an Investment Analysis while being labelled Investment Analysis option 'none' by IGES was 36.4% pre 2010 and 90% afterwards. The share of projects using Investment Analysis from the IGES database has, therefore, been increased by these shares from the sample analysis. Without this correction, the share of projects without investment analysis in the IGES database are 38%, 10% and 14%, respectively, for the three considered time periods of registration.

Sources: IGES 2014, authors' own PDD research

With the adoption of the guidelines, the barrier analysis has largely lost its role as the main argument for demonstrating additionality. After 2010, non-financial barriers are quoted in some projects, but merely as additional information to reinforce the main case for additionality, which tends to be based almost uniformly on investment analysis. Potentially, this development may have been supported by an improved performance of DOEs in validating barrier analysis in PDDs, due to an improved accreditation system.

3.4.3. Summary of findings

In early CDM projects, the routine use of anecdotal and often subjective evidence for claiming barriers has led to the registration of projects with questionable claims for additionality, which cannot be objectively assessed by DOEs. With the adoption of the Guidelines and possibly the improved performance of DOEs, the barrier analysis has largely lost its role as the main line of argument for demonstrating additionality. Rather, barriers are monetized and reflected in the investment analysis.

In the CDM, barrier analysis has lost importance as a stand-alone approach to demonstrating additionality because of the subjectivity of the approach. With the guideline, if barriers are claimed, they are monetized and integrated as costs in the investment analysis.

3.4.4. Recommendations for reform of CDM rules

Non-financial barriers can be important factors preventing the implementation of projects even though they may be profitable. Therefore, considering barriers in approaches for additionality determination is a valid approach.

However, the objective demonstration of barriers (as required in the Guidance) has turned out to be very difficult to operationalise without the reflection and monetization in an investment analysis.

Given the de facto non-application of the barrier analysis without investment analysis approaches in the current CDM practice, we recommend removing the barrier analysis from the additionality and combined tools. In return, key aspects of the Guideline related to the monetization of barriers[31] may be included in the investment analysis step in the additionality and combined tools.

In order to demonstrate additionality of projects with high (non-financial) barriers that may not be monetized, a comprehensive ‘common practice’ analysis or in small-scale projects ‘prevailing practice’ analysis shall be carried out (Section 3.3). Here, objective data on market shares of technologies/project types may be collected that may serve as objective proxy information for the extent to which barriers actually prevent the implementation of projects.

On another note, the approval of “Guideline on objective demonstration and assessment of barriers” by the CDM EB may be seen as a positive example of how the CDM regulator, under the right conditions, can react to an obvious flaw in the rules and practice, and rectify the system.

3.5. Crediting period and their renewal

3.5.1. Overview

Project participants can choose between one crediting period of 10 years without renewal or a crediting period of seven years for their project, which is due for renewal every 7 years for a maximum of two renewals (a total of 21 years for normal CDM projects). (For afforestation and reforestation projects, the choice is between one period of 30 years and three periods of 20 years). The Marrakesh Accords state that for each renewal, a designated operational entity shall determine that “the original project baseline is still valid or has been updated taking account of new data where applicable”.

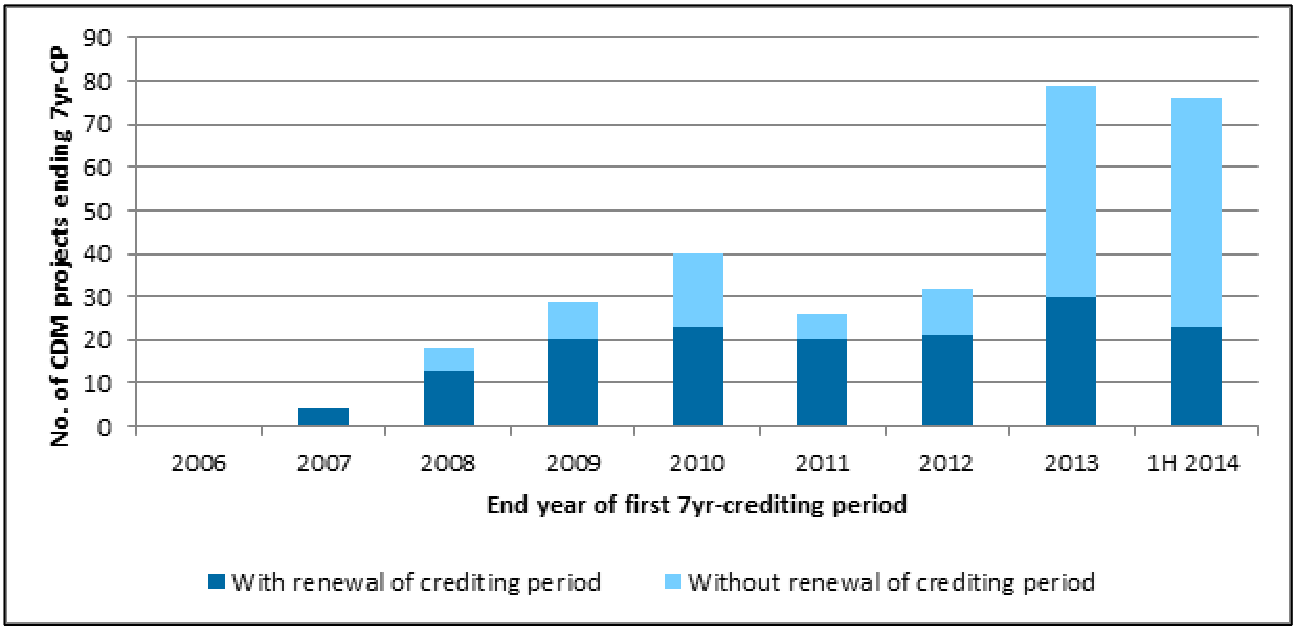
Requirements regarding the renewal of the crediting period were initially adopted in 2006 (EB28, Annex 40), subsequently revised several times (EB33, EB36, EB43, EB46, EB63, EB65, EB66), and partially incorporated in the project standard. At the renewal of crediting period, the latest valid version of a methodology must be used. If a methodology has been withdrawn or is no longer applicable, the project developers may use another methodology or request deviation from an applicable methodology. The CDM EB interpreted the ‘validity test’ in the Marrakech Accords in such a way that neither additionality nor the baseline scenario needs to be reassessed during the renewal of the crediting period. “The demonstration of the validity of the original baseline or its update does not require a reassessment of the baseline scenario, but rather an assessment of the emissions which would have resulted from that scenario” (Project Standard, Version 07.0, paragraph 289). The current rules mainly require an assessment of the regulatory framework, an assessment of

[31] This relates to Guidelines no. 4 and 5 of EB50 Annex 13 that may be integrated as cost items related to barriers/risks in the investment analysis of the additionality and combined tool. Guideline 2 may also be implemented in the context of the investment analysis in the tools, in that the CER revenues should be sufficient to overcome the financial gap in project finance that is due to the barrier.

circumstances, an assessment of the remaining lifetime of technical equipment to be used in the baseline, and an update of data and parameters, such as emission factors.

Figure 3-7 plots the number of projects that have chosen a 7-year crediting period and that end their first crediting period in a given year and are therefore potentially entering a process of crediting period renewal. The increase in project registrations with the maturing of the CDM market from 2005 is mirrored by a steep increase in candidate projects for renewal seven years later, after 2012. The graph also indicates that the fraction of these candidate projects that actually underwent renewal significantly declines after 2012: While before 2012 roughly two thirds of all candidate projects underwent renewal on average, the rate dropped to roughly one third after 2012. This may be explained by the collapse in pricing and the petering out of the classical CDM market in 2011-2012, whereby CER prices below marginal transaction costs make renewal of crediting economically non-viable for most projects that do not benefit from long-term futures contracts with higher prices.

Figure 3-7: Number of CDM projects ending first seven-year-crediting period – with and without renewals



Sources: UNFCCC 2014, authors' own analysis

3.5.2. Assessment

The requirements to use the latest approved version of a methodology is a very important rule to assure that changes in the methodological ruling are also implemented in CDM projects within a reasonable timeframe and therefore seem appropriate. At the same time, it provides some certainty for investors that rules regarding the calculation of emission reductions are not changed within their crediting period.

The CDM EB's decision to interpret the Marrakesh requirement of assessing that “the original project baseline is still valid” in such a way that that only baseline emissions must be updated but that neither additionality nor the baseline scenario needs to be re-assessed could constitute a major risk for the environmental integrity of some project types. In 2011, the Meth Panel highlighted certain issues with this approach in an Information note to the EB (MP51 Annex 21[32]), but the rules were not changed in response. In the following, we briefly analyze two main issues:

- The case of the baseline scenario changing over the course of the crediting period in a way that is not captured by the baseline methodology;
- The case of limited 'lifetime' of a baseline scenario.

Baseline scenario changing over of the course of crediting periods

In a number of instances, a baseline scenario could change over time during crediting periods and deviate from the assumptions in the underlying methodology. One example is a CDM project consisting of the conversion of an existing open cycle power plant to a closed cycle system. Assuming that after the first crediting period, new and lower cost technologies for the conversion would become available that would make the project economically viable, the implementation of the project activity after the first crediting period might be the most probable baseline scenario in the absence of the CDM. We are not referring here to the concept of dynamic baselines, e.g. the fact that baseline emissions are calculated based on the project output (e.g. in tons of steel or MWh per year). Rather, the scenario is changing, i.e. this refers to projects (or another low carbon activity) which, in the absence of the CDM project, would have been implemented at a later date due to changing circumstances.

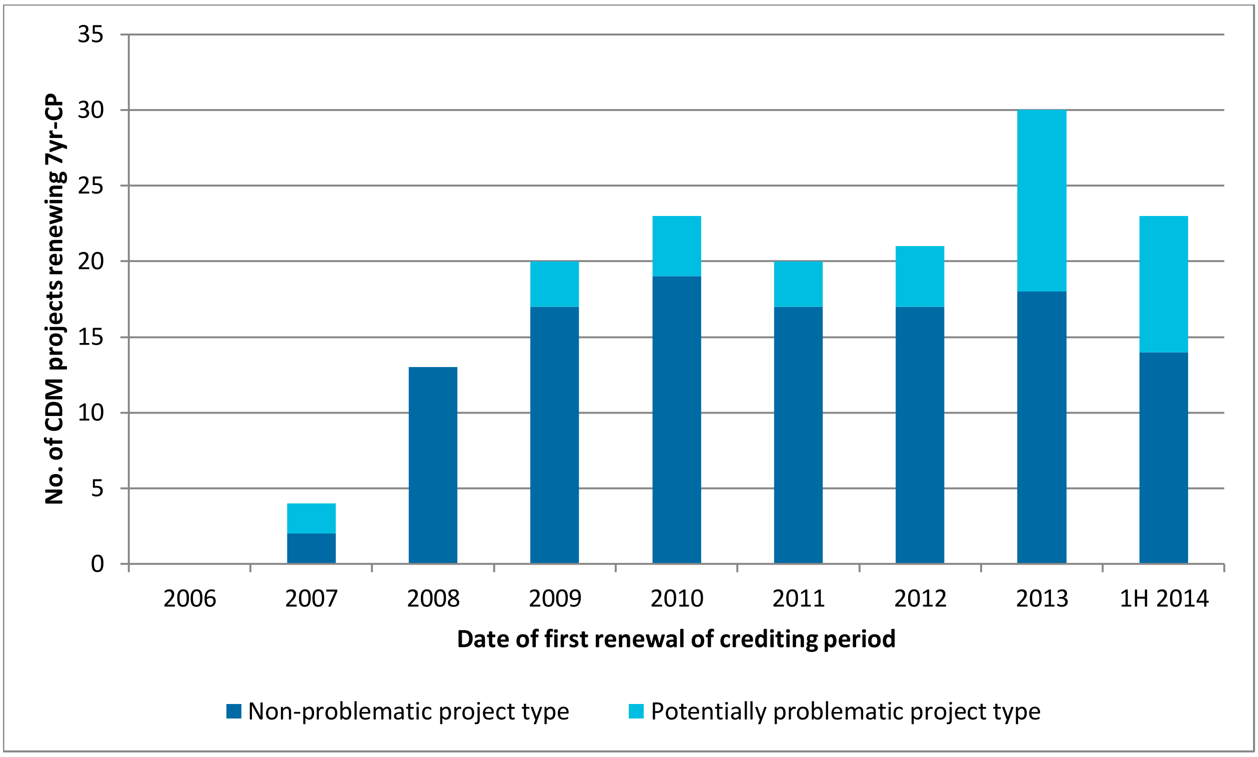
However, it is important to note that not all CDM project types are prone to changing baseline scenarios. Baseline scenarios typically change over time if they are the 'continuation of the current practice'. In such cases, changes such as retrofits could also be implemented at a later stage. In contrast, baseline scenarios do not change over time when they include a significant investment at project start in an alternative that provides similar services. This is the case if, for example, an industry can choose to fulfil their heat demand by either a new biomass boiler (project activity) or a new coal boiler (baseline). If one assumes that the project participant carries out a significant investment at the beginning of the baseline (e.g. to build the new coal boiler), it may be assumed that this investment is used until the end of its operational lifetime; replacing the coal boiler by a biomass boiler after seven years is economically not viable in general.

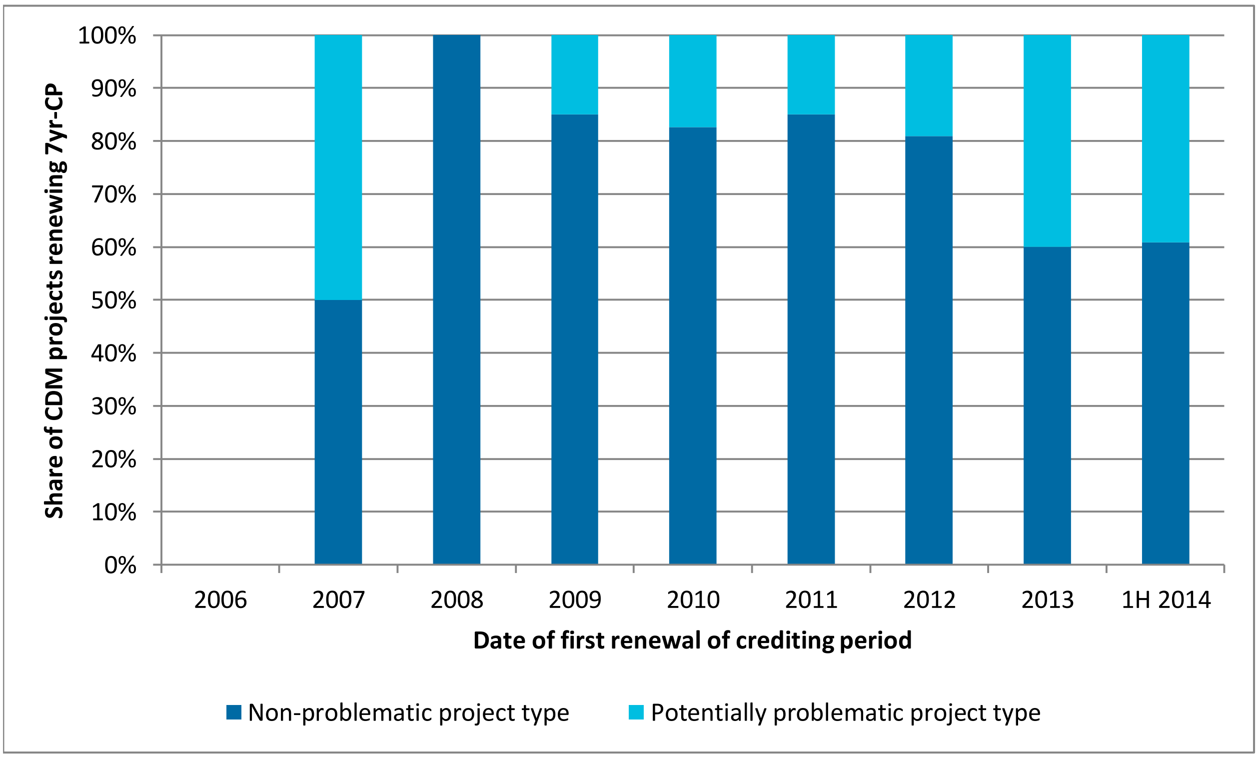
However, because CDM requirements explicitly rule out the re-assessment of the baseline scenario, cases with a change in baseline scenario cannot be taken into account, which leads to potential over-crediting in the second and third crediting periods in the case that the activity would have been implemented after the first crediting period due to changing circumstances.

Practical examples of such changing circumstances and related potential over-crediting can be found in Purdon (2014) for the co-generation sector. The paper provides an overview of how a change in external influence factors (e.g. sugar price) can influence the additionality and how a baseline scenario that is kept constant over several crediting periods can result in over-crediting.

[32] https://cdm.unfccc.int/Panels/meth/meeting/11/051/mp51_an21.pdf.

Figure 3-8: Share of CDM projects renewing their seven year crediting period that is deemed non-problematic





Notes: Potentially non-problematic project types have been selected according to the criteria of having a lower risk of changes in the baseline scenario over several crediting periods.

Sources: UNFCCC 2014, authors' own analysis

Assessment of the scale of the issue

In the following, we make a very rough assessment of the scale of this issue. As mentioned above, not all project types are in danger of undergoing changes in baseline scenarios that are not foreseen in the underlying methodology. In order to arrive at a preliminary estimate of the scale of the potential issue, a list of 'potentially problematic' project types was identified that have a higher risk of changes in the baseline scenario over several crediting periods than those categorised as 'unproblematic'.[33]

Please note that 'potentially problematic' does not mean that all projects in that project type have issues with the renewal of the crediting period, it simply means that the projects are in a sub-type that may contain potentially problematic projects. Figure 3-8 depicts the number of projects of a non-problematic project type in the total number of projects that actually underwent renewal of the 7-year crediting period in a given year.

The graph indicates that the number of projects renewing their crediting periods increased in 2007-2009. Until 2012, non-problematic projects made up the large majority of renewals. However, from 2013 the share of non-problematic projects dropped to approx. 60% of renewed projects. With such a low share, the issue may become more important in the future with a further increase in renewals (although the increase may be somewhat muted by the unfavourable market conditions).

In this context, it is important to note that CDM projects do not need to renewal immediately, but may wait until market conditions are more favourable. Given the high number of projects that may undergo renewal at a later point in time combined with the lowering in the share of non-problematic project types may lead to considerable over-crediting.

Lifetime of baseline scenario

Another, also related, issue is that in more complex and very dynamic systems, such as the transport sector, the determination of a counterfactual baseline scenario is exposed to fundamental limitations in the ability to predict future developments. These limitations can lead to very high uncertainties in the baseline determination. In some instances even after a very few years, the actual baseline emissions could be significantly higher (or lower) than the calculated baseline emissions. For example, while it may be relatively certain that a project proponent choosing in the baseline situation to build a coal-fired boiler will continue to operate this boiler over its lifetime to meet its heat demand, the development of a city's transport system in the absence of a specific urban rail project could be very difficult and uncertain to predict: over some years one may assume that an increase in transport demand is catered for by increased use of private cars; however, street capacities may be limited and the municipalities may have to find solutions to their transport problems anyway, also in the absence of a specific project activity.

It therefore might be considered that for some project types in complex and dynamic environments, such as transport systems, the baseline scenario cannot be reasonably extended over a period of

[33] For a preliminary screening, the following projects sub-types (according to the classification of UNEP DTU) have been classified as "potentially problematic", i.e. it cannot be ruled out that the projects would be implemented later in time without the CDM under changing circumstances (please note that the sub-types may also contain projects which clearly do not have an issue): Adipic acid, Aerobic treatment of waste water, Agricultural residues: mustard crop, Air conditioning, Appliances , Biodiesel from waste oil, Biogas from MSW, Bus Rapid Transit, Cable cars, Caprolactam, Carbon black gas, EE industry – Cement, Cement heat, Charcoal production, EE industry - Chemicals, EE own generation - Chemicals heat, Clinker replacement, CMM & Ventilation Air Methane, CO_2 recycling, Coal Mine Methane, Coal to natural gas, Coke oven gas, Combustion of MSW, Composting, Domestic manure, EE public buildings, Existing dam, Food, Glass, Glass heat, HFC134a, HFC23, Industrial waste, Iron & steel, Landfill composting, Landfill aeration, Landfill flaring, Landfill power, Lighting, Machinery, Manure, Mode shift - road to rail, Natural gas pipelines, Nitric acid, EE industry - Non-ferrous metals, EE own generation - Non-ferrous metals heat, Non-hydrocarbon mining, Oil and gas processing flaring, Oil field flaring reduction, Oil to natural gas, EE industry – Paper, EE industry – Petrochemicals, PFCs, Power plant rehabilitation, Rail: regenerative braking, Solar water heating, Stoves, EE industry – Textiles, Ventilation Air Methane, Waste water. All other project types are deemed "non-problematic".

ten years and a renewal of crediting periods should not be allowed, given the risks of inadequate and very uncertain baseline scenarios for later time periods.

It was for this reason that the crediting period was initially limited to a single crediting period for some project types, including:

- PFC emissions from manufacturing in the semi-conductor industry (e.g. AM0092). This is an industry in which manufacturing technologies and composition of materials etc. change frequently compared to the duration of a 7-year crediting period
- Power saving from efficient management of data centers. Technologies and operating systems also typically have short lifespans compared to a 7-year crediting period.
- Complex transport systems such as the introduction of Bus Rapid Transport (BRT) systems in cities. In this context, the uncertainty in the baseline scenario and the resulting baseline emissions grows very rapidly, because development of transport systems over 5-10 years is difficult to predict with accuracy.

For these project types, the maximum crediting period has been set to 10 years in earlier versions of the methodology, because the uncertainty in the baseline scenario after 10 years did not allow for an objective determination of the emission reduction.

This limit in the crediting period to 10 years also allowed the methodology to be simplified, as the projection of baseline emissions over a limited period allows for simpler approaches and requires less monitoring provisions, thus reducing transaction costs.

Subsequently, however, the CDM EB took the decision (EB67, Para 107) that for each project type and methodology multiple crediting periods can be used (independent of any methodological limitations and uncertainty issues for the baseline setting as discussed above). This decision has been taken based on para 49 of the Modalities and Procedures for the CDM (decision 3/CMP.1, annex) that mentions alternative approaches. The paragraph was interpreted in such a way that both options shall be allowed in *each and every* methodology.

Since then, the relevant methodologies have been revised, allowing crediting for up to 21 years for all methodologies, without providing for further safeguards that would reduce the uncertainty in baseline scenario projection and potential over-crediting.

The issue of renewal of crediting period and more generally the updating of baseline scenarios is further discussed in Schneider et al. (2014).

3.5.3. Summary of findings

When the crediting period of a CDM project is to be renewed, the Marrakesh Accords require that the DOE check the validity of the original project baseline. A subsequent EB ruling (EB 43, Annex 13, paragraph 3) limited this check to an assessment of the regulatory framework, an assessment of the remaining lifetime of technical equipment that would be used in the baseline and an update of data and parameters, such as emission factors. The EB clarified that the validity of the baseline scenario should not be re-assessed.

With CDM project types for which the baseline scenario does not require a significant investment at the beginning of the crediting period (that would determine the baseline technology over the lifetime) this may lead to potential over-crediting. A preliminary analysis of projects that underwent renewal of the crediting period in recent years reveals that from 2013 onwards the share of potentially problematic project types (that might have issues of changing baseline scenarios leading to over-crediting) increases to approx. 40% of projects with renewal. It is therefore recommended that this issue is resolved.

A subsequent ruling by the EB to remove the limit in the crediting period that some project types had in their methodology in sectors especially prone to baseline uncertainty over one crediting period (e.g. semi-conductor manufacturing, information technology, transport) further exacerbated the issue.

3.5.4. Recommendations for reform of CDM rules

We recommend two reforms to the current rules:

- Reassessing the baseline scenario at the renewal of the crediting period: The issue of potential over-crediting arising from inadequate checking of the validity of the baseline at the renewal of the crediting period could be addressed by expanding the assessment to the validity of the baseline scenario for CDM projects that are potentially problematic in this regard. For this, clear criteria for problematic project types should be formulated and guidance should be provided on how to test the validity of baseline scenarios for specific CDM methodologies.
- Limitation of the overall length of crediting for specific project types: Project types in sectors or systems that are highly dynamic and complex, and in which the determination of baselines is notoriously difficult (e.g. urban transport systems) should be limited to a single 10 year CDM crediting period or should be supported by other (non-crediting) finance sources.
- A further step that may be considered is a general limitation of projects to one 7 years crediting period. This may also build on the observation that when discounting future streams of CER revenue beyond 7 (or 10) years at typical hurdle rates longer crediting periods do not really matter for the NPV calculation. Longer crediting periods would only be allowed for project types that require a continuous stream of CER revenues to continue operation such as landfill gas utilization/flaring etc.

3.6. Additionality of PoAs

The advent of CDM Programmes of Activities (PoA) in 2007, and the subsequent refinement of related additionality approaches, changed the nature of additionality testing for many project types. Additionality assessment for PoAs is simplified compared to the requirements for the registration of individual projects. Project developers can establish eligibility criteria to assess additionality, including eligibility criteria, which identify project types that may be automatically additional. More importantly, because the thresholds for identifying small-scale and microscale activities with simplified additionality procedures are set at the level of the Component Project Activity (CPA) and not the level of the PoA, the overall PoA could be far larger than these thresholds. For example, the registered PoA “Installation of Solar Home Systems in Bangladesh” (Ref. 2765) has so far installed 123 MW of solar power and has estimated emissions reductions of 569,000 tCO_2 per year, or almost ten times the small-scale CDM threshold.

In the period of 2013 to 2020, PoAs potentially could supply 0.16 billion CERs. However, as discussed in Section 2.3, the eventual volume for these PoAs could be many times this amount.

3.6.1. Assessment

There are three principle issues with the demonstration of additionality in PoAs: specific additionality concerns about the technology areas covered by PoAs, the robustness of eligibility criteria to check additionality, and the use of small and microscale thresholds for PoAs that are much larger in total than these thresholds. The first point is largely addressed in Chapter 4, because it is related to the mitigation technologies used in PoAs. As shown in Table 2-2, the majority of PoAs are in technology areas that are analyzed in this report (e.g. efficient cook stoves, efficient lighting, wind, hydropower, biomass), so these chapters should be consulted for an assessment of those technologies.

The second point concerns eligibility criteria, namely that the PoA rules require that the project participants develop a set of eligibility criteria that should guide the inclusion of CPAs. The criteria should be constructed so that, for each new CPA, simply confirming that the CPA meets the criteria is enough to ensure that the CPA is additional. These criteria should be based on approaches used in the relevant methodology or other additionality approach that is relevant for the PoA. In other words, there is not a detailed additionality assessment for each CPA in the way that project activities submitted for registration are evaluated. Instead, the eligibility criteria in the registered PoA design document (PoA-DD) should ensure that the CPA meets the relevant additionality test. For example, if part of demonstrating additionality in the relevant methodology is proving that the project is a particular scale or uses a particular technology, then the scale and technology specification would be listed as eligibility criteria against which each new CPA was checked. A possible concern could be that, if the project participants proposed eligibility criteria in the PoA-DD that did not fully capture the additionality requirements of the underlying methodology, there would be a risk that future CPAs could be included even if they were not additional. Although there was some confusion during the early days of PoAs on how to formulate eligibility criteria, this has not been the case since late 2011 when the EB published a standard for eligibility criteria. This was later replaced by the standard for "Demonstration of additionality, development of eligibility criteria and application of multiple methodologies for programme of activities" (CDM-EB65-A03-STAN, version 3.0). This standard provides not only the full list of issues that must be covered in the eligibility criteria, but also clear rules on how additionality may assessed for PoAs.

The third point is perhaps the most important – whether allowing PoAs that are, in total, much larger than the size thresholds for small and microscale projects could increase the risks of non-additionality among PoAs. The small-scale CDM thresholds are 15 MW for renewable energy, 60 GWh savings for energy efficiency, and 60,000 tCO_2 per year emissions reductions for other project types with approved small-scale methodologies. The scale limits for the microscale additionality rules are 5 MW for renewable energy, 20 GWh savings for energy efficiency projects, and 20,000 tCO_2 for other project types, and are then combined with other criteria (described in detail in Chapter 4, e.g. country type, size of individual units, or even designation by a national authority), to qualify as automatically additional. However, the EB decided at their 86th meeting that microscale technologies using unit size as the basis of automatic additionality (i.e. independent units of < 1500 kW for renewables, < 600 MWh for energy efficiency and < 600 tCO_2 for other projects, all serving households and communities) would have no limit of the total scale of the project or CPA. In other words, an efficient cook stove project activity or CPA could have total emission reductions of greater than 20, or even 60, $ktCO_2$ per year.

Projects (in this case, CPAs) that qualify as small-scale CDM (SSC) then have access to the technology-based 'positive list' in the tool for "Demonstration of additionality of small-scale project activities" (Tool21, version 10.0). CPAs below the micro-scale thresholds would all be automatically additional as long as they meet both the scale and other requirements (e.g. technology, location, etc.). For small-scale CDM, the list of technologies considered automatically additional includes the following:

- Certain technologies whether grid-connected or off-grid: solar (PV and thermal), off-shore wind, marine (wave and tidal), and building-integrated wind turbines or household rooftop wind turbines up to 100 kW;

- Additional off-grid technologies below the SSC thresholds: micro/pico-hydro (with power plant size up to 100 kW), micro/pico-wind turbine (up to 100 kW), PV-wind hybrid (up to 100 kW), geothermal (up to 200 kW), biomass gasification/biogas (up to 100 kW);
- Technologies with 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-scale CDM thresholds;
- Rural electrification projects using renewable energy in countries with rural electrification rates less than 20%.

Both microscale additionality and the small-scale CDM positive list approaches have been used extensively by PoAs. As shown in Table 3-2, 33% of the CPAs in registered PoAs, representing 27% of expected CERs, have applied the microscale or small-scale positive list approaches ('first of its kind' is discussed in Chapter 4). An analysis by the UNFCCC Secretariat[34] also shows that 142 of the 282 registered PoAs use microscale or small-scale rules for automatic additionality, with 65% of PoAs targeting households utilising one of these tools (Table 3-3). Many of these PoAs have already exceeded the microscale and small-scale thresholds at an aggregate level, as allowed in the CDM PoA rules. In contrast, the 120 CDM project activities that have used small-scale positive lists or microscale guidelines comprise only 0.8% of projects and 0.1% of expected emissions reductions (UNEP DTU 2015a).

Table 3-2: Use of automatic additionality approaches in CPAs within registered PoAs

Approach for automatic additionality	Annual CERs ($ktCO_2$/yr)	CPAs	CERs	CPAs
Microscale tool: country, unit size or DNA selection	3,520	188	11%	23%
Microscale tool: SUZ	60	9	0%	0%
SSC positive list	5,078	91	16%	10%
None	21,279	551	70%	65%
Total	29,936	839	100%	100%

Notes: A more recent version of the PoA pipeline was used here because of a revision of how the use of automatic additionality is classified.

Sources: UNEP DTU 2015b

[34] "Concept note: Thresholds for microscale activities under programmes of activities" (CDM-EB85-AA-A09)

Table 3-3: Technology and end-user types in registered PoAs that applied microscale and/or small-scale positive list criteria

Technology type	PoAs	Share of this type of PoA
End use type: Households	**92**	**65%**
Household biogas digesters	13	
Energy efficiency - household	2	
Energy-efficient lighting (LED and CFL)	28	
Improved cookstoves	36	
Solar water heaters	7	
Water purifiers	5	
Renewable-based rural electrification	1	
End use type: Others	**50**	**35%**
Energy efficiency – industrial	2	
Fuel switch	3	
Grid/off-grid connected renewable energy technologies (e.g. wind, solar PV, geothermal)	35	
Waste treatment (e.g. Wastewater, animal waste)	10	
Total	**142**	**100%**

Sources: Concept note: Thresholds for microscale activities under programmes of activities (CDM-EB85-AA-A09)

Whether granting automatic additionality to PoAs that are over the small and microscale thresholds poses a risk for additionality testing depends on the *reason* for the positive list designations. One of the main issues raised by the positive list is the *unit size* of the technology, with the argument being that the unit size on its own may be sufficient to identify a project type with a high likelihood of additionality (in combination with the other microscale criteria, where relevant). On this basis, the EB recently agreed that the size criterion for the microscale additionality tool should be *only* unit size, and not total project size.[35] This means that even a PoA using a large-scale methodology and have a total size beyond the SSC thresholds can still apply microscale additionality guidelines, as long as the unit size and other criteria are met.

The SCC positive list sets unit size limits for most categories of eligibility, although not for rural electrification or the grid-connected technologies (other than the 15 MW limit). The microscale guidelines also include the option of using a unit size less than 1% of the SSC threshold as a justification for applying these guidelines even if the projects are not located in Least Developed Countries (LDCs) or Special Underdeveloped Zone (SUZs).

The most important categories of PoAs (in terms of their contribution to expected CERs) utilising these tools are improved cook stoves, energy efficient lighting, biogas and small unit size solar power[36]. For the first three technologies, the unit size is inherently small, so the size of the total project or PoA should not, by itself, determine the viability of the technology (bearing in mind, however, that overhead programme costs are obviously lower per unit for larger programmes). The additionality issues with improved cook stoves and energy efficient lighting are reviewed in Sections 4.12 and 4.13, respectively. These sections raise important questions about the additionality

[35] The changes to the Tools for “Demonstration of additionality of small-scale activities” (version 22) and “Demonstration of additionality of microscale project activities” (version 07) were approved at EB86 (October 2015), as were changes in the Project Standard, Project Cycle Procedure, and standard on standard on “Demonstration of additionality, development of eligibility criteria and application of multiple methodologies for programmes of activities.”

[36] Although the table from the UNFCCC Secretariat refers to “Grid/off-grid connected renewable energy technologies (e.g. wind, solar PV, geothermal)”, our analysis has not identified any wind or geothermal PoAs using the small-scale positive list or the microscale guidelines.

of these project types, despite their small unit size, particularly because of the role of other support programmes in promoting these technologies and possible over-crediting for cook stoves, for example. On the other hand, the extensive literature on household energy access technologies and carbon markets also points to numerous well documented barriers, and the high unit transaction costs associated with small unit size technologies (e.g. Gatti & Bryan 2013; IFC 2012; Warnecke et al. 2015, 2013). In addition, the analysis from the UNFCCC Secretariat mentioned earlier also shows that the average unit size of PoAs using the small-scale and microscale positive lists is, in fact, far below even the microscale unit size of 1% of the SSC threshold (Table 3-4).

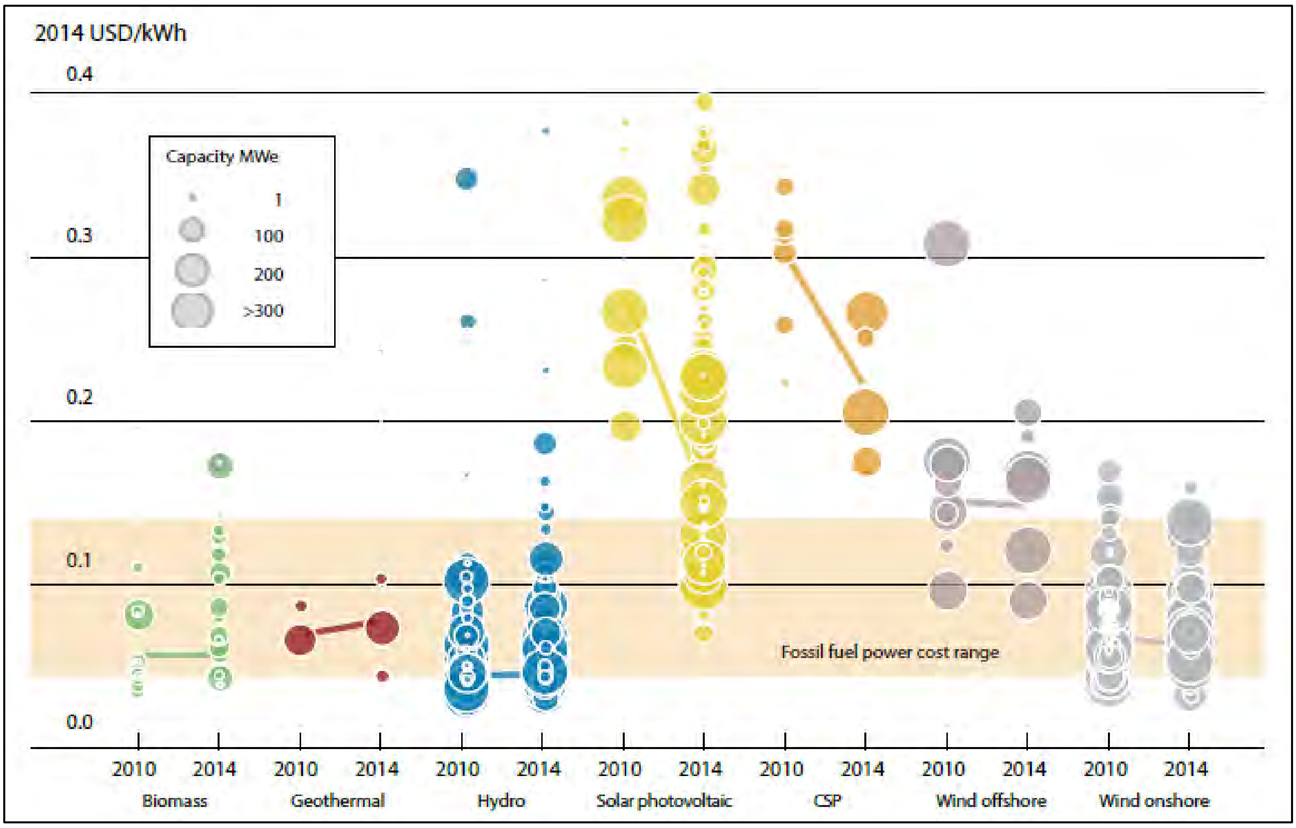
Table 3-4: Size of individual units in microscale and small-scale PoAs using positive lists

Unit size as % of SSC threshold	Type I (kW)	Type II (MWh)	Type III (tCO2)
1%	150	600	600
PoAs applying microscale criteria			
Average – 0.022%	3.3	13.3	13.2
Std deviation – 0.054%	8.1	32.4	32.4
PoAs applying small-scale criteria			
Average – 0.23%	34	136	137
Std deviation – 0.34%	51	204	204

Sources: Concept note: Thresholds for microscale activities under programmes of activities (CDM-EB85-AA-A09)

For renewable power technologies, even if the total capacity of a PoA was over 15 MW, the unit size could not be larger than 5 MW for most technologies (15 MW for solar PV or solar thermal) to qualify for automatic additionality. Given the economies of scale in renewable energy power generation (Prysma 2012), small unit sizes would be expected to have higher capital costs, and would therefore be more likely to face investment barriers than larger scale plants. Project-level analysis by the International Renewable Energy Agency (IRENA) also suggests that smaller renewable energy plants not only have higher costs (i.e. because the smaller dots, representing smaller scale projects, are generally higher up in the figure), but that for solar PV and solar thermal these costs are still considerably higher than for fossils fuels (Figure 3-9). Analysis by EPRI has also shown that solar power at the several MW scale is considerably more expensive than conventional alternatives (EPRI 2012). This suggests that a solar PV (grid connected or off-grid) programme of any total size would not be economically viable if the units were below the small-scale thresholds. However, the challenge with solar technologies is that they are so expensive that carbon revenue is unlikely to close the financial viability gap, so they may be more driven by national policies than carbon markets (Section 3.7).

Figure 3-9: Levelized cost of electricity from renewable technologies, 2010 and 2014



Notes: Size of the diameter of the circle represents the size of the project. The centre of each circle is the value for the cost of each project on the Y axis. The LCOE of a given technology is the ratio of lifetime costs to lifetime electricity generation, both of which are discounted back to a common year using a discount rate that reflects the average cost of capital.

Sources: IRENA (2015)

On the basis of the unit size analysis shown in Table 3-4, the Secretariat prepared a concept note with recommendations to the EB using on unit size, and not total project or CPA size, as the basis for determining microscale additionality (CDM-EB85-AA-A09). The EB agreed to begin to implement an approach of using only a unit size threshold to determine if the size of the project qualifies for microscale (EB85 report, paragraph 42). The other requirements for microscale (e.g. location in an LDC or SUZ, if the unit size is greater than 1% of the SSC threshold) would remain unchanged. This means that the CPAs comprised of technologies that were below the unit size threshold would not be limited in their total size. For example, a CFL PoA in an LDC could have a CPA with 100,000 MWh savings and still apply the microscale additionality guidelines.

3.6.2. Summary of findings

While the PoA rules do allow programmes with a total size greater than the small-scale and microscale thresholds to utilise the automatic additionality provisions for these scales of projects, there is no evidence that this increases the risk of non-additional projects on its own (i.e. the share of projects that could be non-additional). In other words, the PoA rules do not fundamentally change the additionality risks for a given category of project technologies. The PoA process could, of course, increase the overall *scale* of the risk because they were designed to facilitate the large scale dissemination of small, distributed technologies. For example, there are 40 registered 'improved stove' project activities with expected CERs of 1 million tCO_2 per year, but there are 46 registered 'improved stove' PoAs that already have expected CERs of 8.1 million tCO_2 per year.

3.6.3. Recommendations for reform of CDM rules

Reform of the CDM rules related to additionality for particular project types and positive lists will address any concerns about additionality of PoAs.

3.7. Positive lists

The concept of 'positive lists' means that specific project types are considered automatically additional. Positive lists are one option to reduce transaction costs and increase the certainty of the CDM system from the perspective of project developers. Similar to standardized baselines, creating a positive list requires an upfront evaluation of technologies and their economic and regulatory environment, independent of the assessment of a particular CDM project proposal, to establish certain objective criteria that, if met, will result in a high likelihood of additionality. Once a positive list is established, a specific CDM project only needs to show that the pre-defined criteria are met, and does not have to apply other tools to justify additionality.

3.7.1. Positive lists in the CDM and impact on CER supply

Positive lists were introduced in the CDM through various routes. As briefly mentioned in Section 3.6, the CDM EB adopted the "Guidelines for demonstrating additionality of micro-scale project activities" in 2010, which were subsequently converted to a methodological tool, which first established automatic additionality for certain project types regardless of the type of methodology used (i.e. small-scale or large scale). Table 3-5 shows the technologies covered under version 7 of that tool, and the criteria they must meet in order to be deemed automatically additional. In addition to total project size (or, in the case of PoAs, the size of an individual CPA), the technologies must meet a further criterion such as location, unit size and/or consumer group.

Table 3-5: Projects considered automatically additional under the tool "Demonstration of additionality of microscale project activities"

1	**Based on country (LDCs, SIDSs)** • Renewable energy up to 5 MW • Energy efficiency up to 20 GWh savings per year • Other small-scale CDM projects (Type III) up to 20 $ktCO_2$ emissions reductions per year
2	**Based on unit size and consumer (households, communities, SMEs) (i.e. any country)** • Renewable energy of any size as long as unit size is less than 1500 kW • Energy efficiency of any size as long as unit savings are less than 600 MWh per year • Other small-scale CDM projects (Type III) of any size as long as unit savings are less than 600 tCO_2 per year
3	**Based on host country designation of special underdeveloped zone (SUZ)** • Renewable energy up to 5 MW • Energy efficiency up to 20 GWh savings per year • Other small-scale CDM projects (Type III) up to 20 ktCO2 emissions reductions per year
4	**Based on designation of a technology by the host country** • Grid connected renewable energy specified by DNA, up to 5 MW, which comprises less than 3% of total grid connected capacity
5	**Based on other technical criteria** • Off-grid renewable energy up to 5 MW supplying households/communities (less than 12 hours grid availability per 24 hours is also considered 'off-grid')

Notes: LDCs = Least Developed Countries, SIDSs = Small Island Developing States, SME = Small and micro enterprises, DNA = Designated National Authority.
Sources: Tool for "Demonstration of additionality for microscale activities"

In 2011, the "Guidelines on the demonstration of additionality of small scale project activities", which later were similarly converted to a methodological tool, also included for the first time a list of technologies that would be considered automatically additional for any project meeting the small-scale CDM thresholds. This initially only included a list of grid and off-grid renewable energy technologies (i.e. the first two blocks in Table 3-6), but was expanded in 2012 to include small isolated units serving communities and renewable energy-based rural electrification.

Table 3-6: Technologies considered automatically additional under the tool “Demonstration of additionality of small-scale project activities”

6	**Renewable energy (up to 15 MW, grid or off-grid, all end users)** • Solar PV and solar-thermal electricity generation • Offshore wind • Marine technologies (e.g. wave and tidal) • Building integrated wind turbines or household roof top wind turbines (unit size =< 100 kW)
7	**Renewable energy (up to 15 MW, off-grid only)** • Micro/pico-hydro (unit size =< 100 kW) • Micro/pico-wind turbine (unit size =< 100 kW) • PV-wind hybrid (unit size =< 100 kW) • Geothermal (unit size =< 200 kW) • Biomass gasification/biogas (unit size =<100 kW)
8	**Distributed technologies for households/communities/SMEs (off-grid only)** • Aggregate size up to SSC threshold (15 MW, 60 GWh or 60 ktCO_2 emission reductions) with unit size =< 5 per cent of SSC thresholds (i.e. =< 750 kW, =< 3 GWh/y or 3 ktCO_2e/y)
9	**Rural electrification using renewable energy** • In countries with rural electrification rates less than 20%

Notes: Numbers in left hand column continue from previous table.
Sources: Tool for “Demonstration of additionality of small-scale activities” (version 10.0)

In addition to these tools, which apply across many methodologies, some individual methodologies have provided for automatic additionality for certain project types, often related to regulations. The most widely used is ACM0002 “Grid-connected electricity generation from renewable sources” (version 16.0), which was revised in November 2014 to include a two-part positive list for grid connected technologies. The first part is a list of technologies that are considered automatically additional: solar PV, solar thermal, offshore wind, marine wave and marine tidal (i.e. the technologies included in the first part of the small-scale CDM additionality tool, except at larger scale). The second part says that any technology with less than 2% of the total grid-connected capacity or less than 50 MW total capacity in the country is considered automatically additional. Since the revision of ACM0002, ten new project activities have requested and completed registration (no new PoAs have been registered). Of these, only one project has applied the new positive list provisions – a 141 MW solar PV facility in Chile. This is the largest solar facility to be granted automatic additionality.

Another important methodology with automatic additionality provisions includes ACM0001 “Consolidated baseline and monitoring methodology for landfill gas project activities” (version 15.0), which was revised in late 2013 to consider the following technologies automatically additional if, prior to the project activity, landfill gas was only vented and/or flared:

- electricity generation in one or several power plants with a total nameplate capacity that equals or is below 10 MW;
- heat generation for internal or external consumption;
- flaring (assuming no flaring prior to the project).

AM0113 “Distribution of compact fluorescent lamps (CFL) and light-emitting diode (LED) lamps to households” (version 01.0) provides for automatic additionality for any project distributing self-ballasted LED lamps to households. Projects distributing CFLs are only considered automatically additional if they are in a country with “no or only limited lighting efficiency regulations” reported by the UNEP en.lighten initiative’s Efficient Lighting Policy Status Map. AM0086 “Distribution of zero energy water purification systems for safe drinking water” (version 04.0) considers projects automatically additional if less than 60 percent of the population has access to improved drinking water sources or if the project proponents can demonstrate that more than half of the improved drinking water delivered does not actually meet the appropriate health standards. AMS-III.D “Methane recovery in animal manure management systems” (version 19.0) considers projects automatically additional when there is no regulation that requires the collection and destruction of methane from livestock manure. In addition to these, AM0001 “Decomposition of fluoroform (HFC-23) waste streams” (version 6.0), the first approved large-scale methodology, essentially uses a positive list approach based on regulation, because any project that does not face a regulatory requirement to abate HFC-23 emissions is considered additional. The same is true for ACM0019 “N_2O abatement from nitric acid production” (version 02.0).

While the positive lists presented above have not been used widely by CDM project activities (e.g. only 121 registered projects), PoAs have utilised the lists in the small-scale and microscale additionality tools (Table 3-2), with a third of CPAs in registered PoAs using these additionality approaches. Whether this growing group of PoAs presents concerns for the additionality depends on the strength of the justification for the original positive lists and for how long this justification is likely to be valid (i.e. how often the lists should be updated).

The criteria used to select the positive lists as well as the validity of these lists are presented in an information note prepared by the Small-scale Working Group in November 2014 called “Criteria for graduation and expansion of positive list of technologies under the small-scale CDM” (CDM-SSCWG46-A23). Table 3-7 summarises all of the positive list approaches, and shows the range of criteria used. The individual methodologies often refer to regulations to determine automatic additionality, or current penetration rates. The small-scale and microscale additionality tools use a mix of end-users, location, cost of service and penetration rates, depending on the specific technology group. This also highlights the similarity between positive lists discussed here and standardized baselines (Section 3.8), which also define a list of automatically additional technologies based on penetration rates and comparative costs.

Table 3-7: Criteria used for determining positive lists

		End-user	Regula-tion	Location	LCOS	Penetra-tion	Capital cost
1	Microscale based on country (LDCs, SIDSs)						
	Renewable energy < 5 MW; Energy efficiency < 20 GWh; Other up to 20 $ktCO_2$			x			
2	Microscale based on unit size and consumer (households, communities, SMEs) (i.e. any country)						
	Renewable energy < 5 MW and unit size <1500 kW; Energy efficiency < 20 GWh and unit savings < 600 MWh; Other < 20 $ktCO_2$ with unit savings < 600 tCO_2	x					x
3	Microscale based on host country designation of special underdeveloped zone (SUZ)						
	Renewable energy < 5 MW; Energy efficiency < 20 GWh; Other < 20 $ktCO_2$			x			
4	Microscale based on designation of a technology by the host country						
	Grid connected renewable energy specified by DNA, up to 5 MW, < 3% of capacity					x	
5	Microscale based on other technical criteria						
	Off-grid renewables < 5 MW supplying households	x					
6	Small-scale renewable energy (up to 15 MW, grid or off-grid, all end users)						
	Solar PV and solar-thermal electricity generation; off-shore wind; marine (e.g. wave and tidal); building integrated wind turbines or household p wind =< 100 kW				x		
7	Small-scale renewable energy (up to 15 MW, off grid only)						
	Micro/pico-hydro (unit <= 100 kW); micro/pico-wind (unit <= 100 kW); PV-wind hybrid (unit <= 100 kW); geothermal (unit <= 200 kW); biomass gasification/biogas (unit <= 100 kW)						x
8	Small-scale off-grid distributed technologies for communities						
	Unit size =< 5 per cent of SSC thresholds	x					
9	Rural electrification using renewable energy						
	In countries with rural electrification rates less than 20%						
10	AM0086 water purification						
	<60% access to improved drinking water and <50% use of point-of-use zero energy water purification					x	
11	AM0113 energy efficient lighting						
	CFLs in countries with no or limited regulatory support All self-ballasted LED lamps		x			x	
12	ACM1 landfill gas utilisation						
	LFG for electricity or heat where vented or flared, or flaring where previously vented					x	x
13	AMS III.D methane and manure management						
	Biogas for power < 5 MW where no regulation requires collections and destruction of methane		x				
14	AMS III.C electric and hybrid vehicles						
	Market share of electric/hybrid vehicles < 5%					x	

Notes: LCOS = Levelized cost of service, LDCs = Least Developed Countries, SIDSs = Small Island Developing States, SMEs = Small and micro enterprises, DNA = Designated National Authority.

Sources: UNFCCC documents as cited in text

In terms of the duration of validity of the positive lists, the small-scale and microscale additionality tools did not originally include a time limit, although many of the methodologies specify a three-year duration of validity. The EB (EB81, paragraph 72) accepted a Small-Scale Working Group recommendation in late 2014 to set a three-year limit on validity for the small-scale CDM positive lists. In addition, the EB agreed on thresholds for 'levelized cost of service', 'penetration rate', and 'capital cost#, as shown in Table 3-8. Note that these new rules only apply to the positive lists under the tool for "Demonstration of additionality of small-scale project activities", and not to microscale activities or any other positive lists.

Table 3-8: Graduation criteria for technologies under the tool for "Demonstration of additionality of small-scale project activities"

	End-user	LCOS	Penetration	Capital cost
Grid connected renewable electricity generation				
All renewable energy technologies in the current positive list		>= 50% higher than all fossil fuels	Global average penetration <3%	
Off-grid renewable electricity generation				
All off-grid renewable technologies in the current positive list				>= 3 times the cost of all fossil fuels
Distributed technologies for households/communities/SMEs				
All distributed technologies eligible under Type I/II/III and providing services of households/communities/SMEs	Assess appropriateness of user groups		Global average penetration rate < 3%	>= 3 times cost of all plausible baseline technologies

Sources: Information note "Criteria for graduation and expansion of positive list of technologies under the small-scale CDM" (CDM-SSCWG46-A23)

3.7.2. Assessment of current positive lists

The positive lists developed under the CDM to date are based on specific criteria such as penetration rate, costs, regulatory environment, and location. While these lists have not been used widely for automatic additionality among CDM project activities, their use among PoAs is widespread and growing. 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 other project types, in particular those covered by the microscale additionality tool or approaches used in relevant methodologies (e.g. ACM0002).**

An important challenge with the current positive lists, however, is that the basis upon which they are established varies widely, without a clear rationale for the choice or level of the indicator (e.g. why penetration might be used for some technologies but levelized cost of service for others). **A consistent approach to determining technology eligibility is needed** to ensure that existing and new positive lists do not pose risks of non-additionality. The criteria and indicators used should have clear justification for how they influence project implementation. For example, while low market penetration or high capital costs could be strong indicators of prohibitive barriers for some technologies, it is not clear how the concept of 'special underdeveloped zones' (SUZ), which may be defined differently by each DNA according to UNFCCC guidelines, is a reliable indicator of barriers.

As part of the justification of project types and technology choices, **positive lists must address the impact of national policies and measures to support low emissions technologies** (so-called, E- policies). As discussed in Section 3.9 and many of the sections within Chapter 4, national policies may be the primary driving factor for the implementation of certain technologies, rather than their underlying economics, market position or location. In fact, one of the criticisms of allowing renewable technologies to be considered automatically additional is that their costs are so high that carbon revenue alone cannot possibly make them financially viable, and so other incentives and policies are the real determining factor (Lazarus et al. 2012; Spalding-Fecher et al. 2012). This is even truer with smaller scale technologies. For example, in a study in Southern Africa, the levelized cost of roof-top solar PV was 20% more expensive than utility scale solar PV, while small hydropower was 70% more expensive than large scale (Miketa & Merven 2013). 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. An example of this would be the REN21 renewable energy global overview and interactive map,[37] which provides a comprehensive technology-specific database of the policies in place to support renewables. A positive list that included renewables could therefore be qualified by restricting its applicability to countries that did not have any support policies in place for that technology. Having support policies in place does *not*, on its own, mean that those technologies would not be additional, but only that there is a greater risk of this and so applying a positive list approach in that country would not be appropriate. Projects in those countries could still use the other tools available for demonstrating additionality for small- and large-scale projects – they would only not have access to automatic additionality based on the positive list. As an example, the positive list in the tool for "Demonstration of additionality of small-scale project activities" includes all solar PV and solar thermal technologies in all CDM-eligible countries. According to the REN21 policy database, however, the following countries have support policies[38] in place for solar PV: Algeria, Argentina, Brazil, Cape Verde, China, Côte d'Ivoire, Ecuador, Egypt, Gambia, Ghana, India, Jordan, Lebanon, Malaysia, Mauritius, Nepal, Nigeria, Republic of Korea, Senegal, Thailand, Uruguay, Uzbekistan, and Venezuela. For these countries, therefore, it might be more appropriate to require an analysis of barriers to solar PV rather than considering them automatically additional. This approach could be refined based on additional research into publicly available and up-to-date databases of renewable energy policies.

Finally, to maintain environmental integrity of the CDM overall, **positive lists should be accompanied by negative lists**. This is because the introduction of a positive list without any negative list could, by definition, only lower environmental integrity compared to the traditional approaches. Projects that do not fall within the positive list can still apply the traditional approaches. So, the positive list will lead to more 'false negatives' passing the test, but will not rule out any projects that are not additional. Overall, environmental integrity is thus lowered (albeit with the positive element of reducing transaction costs). An exception to this could be the few methodologies that deem projects as ineligible if they reach a market penetration threshold above a certain level, because they, in essence, include both a positive and negative list.

[37] The interactive map is shown at: http://www.ren21.net/status-of-renewables/ren21-interactive-map/ . The full database of policies is available at http://www.ren21.net/wp-content/uploads/2015/09/Downloadable-Consolidatedv1.2.1.xlsx.

[38] Support policies may include, for example, feed-in tariffs, electric utility quota obligation, capital subsidies, tax credits, and net metering, but exclude renewable energy targets not accompanied by other incentives.

3.8. Standardized baselines

Project developers have repeatedly complained about the expensive and time-consuming process for formally registering a project under the CDM. The setting of the baseline for the greenhouse gas emission reductions associated with a project has required project developers to apply project specific methodologies in order to calculate baseline emission levels. The project developers take on significant costs before the approval of their project when collecting the data necessary to set the baseline and demonstrate additionality. In some cases the risks associated with these upfront costs may be too high for developers of smaller projects in poorer countries (Spalding-Fecher & Michaelowa 2013) – impacting the regional distribution of projects under the CDM. Apart from high transaction costs, the project-specific determination of baselines and assessment of additionality has been criticised in the past for being subjective (Schneider 2009). Due to the information asymmetry between project developers and DOEs subjective assumptions may be difficult to verify, which could result in non-additional projects or over-crediting, which both undermine the environmental integrity of the CDM.

The Cancun Agreements in 2010 provided for the use of *standardized baselines* in the CDM to address these limitations with the aim *"to reduce transaction costs, enhance transparency, objectivity and predictability, facilitate access to the clean development mechanism, particularly with regard to under-represented project types and regions, and scale up the abatement of greenhouse gas emissions, while ensuring environmental integrity"* (UNFCCC 2011c). In contrast to the project-by-project approach to setting baselines and demonstrating additionality, standardized baselines are established for a project type or sector in one or several CDM host countries. Standardized baselines can address any or all of three areas for standardization: demonstrating additionality, determining the baseline scenario or determining baseline emissions. In the latter case, standardization can include emission factors or individual parameters needed to calculate emission reductions.

Standardized baselines require host country approval and are submitted through the DNA of the host Party. They can cover one or several Parties. Once approved, project developers can use a standardized baseline when submitting a project for registration. In 2014, the EB further decided that it is up to the host Parties to decide whether projects must use an approved standardized baseline or whether they may alternatively use a project-specific approach, but noted that the EB could reject standardized baselines if this poses a risk to environmental integrity (CDM-EB78, para 24). In practice, all approved standardized baselines have so far been voluntary, except for a multi-country grid emission factor in the Southern African region.

The CDM allows standardized baselines to be derived either from suitable methodologies, from tools such as the *'Tool to calculate the emission factor for an electricity system'*[39] or from a generic framework that is applicable to all project types and sectors such as the *'Guidelines for the establishment of sector specific standardized baselines'*[40] adopted by the EB in 2011. Further regulatory documents include a procedure for submission of standardized baselines, a standard on the coverage and vintage of data, and guidelines for quality assurance and quality control.

The *'Guidelines for the establishment of sector specific standardized baselines'* combine elements of market penetration, performance benchmarks, investment and barrier analysis. Under this framework, the standardized baseline results in a positive list of fuels, feedstocks and/or technologies for a given sector. The least emission-intensive fuel/feedstock/technology needed to produce

39 https://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v2.pdf.

40 https://cdm.unfccc.int/filestorage/4/I/Y/4IY1RB7DMKLWPGF59XC3UE6JNH8Q2A/eb62_repan08.pdf?t=N2d8bnRoeHN3fDDSYyp3xU9Kx6IMk5Ho1yFw.

a certain percentage of the sector's output (i.e. defined by the CDM EB)[41] is selected as the baseline fuel/feedstock/technology. All fuels/feedstocks/technologies that are associated with lower emission intensities than the baseline technology are candidates for inclusion in a positive list of fuels/feedstocks/technologies that are automatically deemed additional. The DNA of the host country also needs to demonstrate for each of the candidates for the positive list that they are either less economically attractive than the non-candidates or face barriers to entry (Schneider et al. 2012). The baseline technology is also used to determine the baseline against which emission reductions are calculated (Hermwille et al. 2013).

Table 3-9: Approaches for deriving grid emission factors

DNAs could use either the standardized baseline guidelines or the grid emission factor tool to determine the grid emission factor and submit the value as a standardized baseline. The weaknesses of this opportunity to choose between two alternative approaches are explained below:

1) **Pick and choose issue:** The two approaches will provide two different values for the grid emission factor. Thus, the DNA could pick and choose between two completely different methodological approaches for determining the grid emission factor. Countries for which the guidelines result in higher values will use that approach, whereas countries for which the tool results in higher values will use that approach. Overall, having two parallel approaches could undermine the environmental integrity compared to the current situation in which only one approach is available.

2) **Vintage of data issue:** The standardized baseline guidelines consider all plants, whether they were recently constructed or decades ago. This could result in a situation in which coal power is determined as the baseline fuel, even if no coal power plant has been constructed or been under construction for a decade. In contrast, the grid emission factor tool aims to consider recent developments by observing which plant types were recently added to the system or are under construction or which plants actually operate at the margin.

3) ***'One size fits all'* issue:** The grid emission factor tool uses a methodologically approach that considers the particularities of the electricity system, considering different possible effects of displacing grid electricity (marginal plants not being dispatched/the construction of other power plants avoided or delayed). In contrast, the guidelines do not consider the characteristics of the sector and make generalised assumptions, which have little meaning in the power sector. The guidelines therefore result in less accurate grid emission factors than the grid emission factor tool.

Sources: Own compilation

The environmental impact of standardized baselines will be affected by how stringently the standardized baseline is set for a given project type. The stringency of standardized baselines needs to safeguard the environmental integrity of the CDM whilst also striking the right balance between accuracy and transactions costs in order to ensure that there is an incentive for developing new CDM projects.

The implications of standardized baselines on environmental integrity will also vary depending upon the sector that they are applied to, as the approach relies considerably upon the assumption that the penetration of a fuel/feedstock/technology is negatively correlated with its cost and/or with barriers that impede their deployment (Hermwille et al. 2013). For certain sectors there will undoubtedly be a strong correlation, i.e. energy efficient lighting and efficient electrical appliances.

[41] In its guidance, the EB has defined a preliminary additionality/crediting threshold of 80 % in priority sectors and 90% in other sectors.

However for other sectors, i.e. with multiple products or with strongly varying circumstances among installations, the correlation will be weaker or absent and alternative approaches for setting baselines and demonstrating additionality may be more suitable (Hermwille et al. 2013). Applying the current framework to sectors for which such a correlation is lacking could broaden the positive lists for technologies that are unlikely to be additional. In the power sector, for example, the guidelines do not reflect the particular features of an electricity system. The Methodologies Panel recommended that the EB limits the applicability of the SB standard to sectors other than the power sector (MP65, paragraph 38 and 39). In response, the EB requested the Methodologies Panel to assess the applicability of the proposed framework to different project types (EB81, paragraph 41). However, as of January 2016, the current guidelines are still applicable to all sectors. In 2015, a standardized baseline was finalized for consideration by the EB, which includes grid emission factors for different islands of Cape Verde and applies for some islands the "*Guidelines for the establishment of sector specific standardized baseline"* and for others the grid emission factor tool. The issues arising from the application of the guidelines to the power sector are highlighted in Table 3-9.

The following issues may pose further environmental risks through the implementation of standardized baselines in the future:

- **Mandatory versus voluntary use of standardized baselines:** The current CDM EB framework does not make the use of standardized baselines mandatory (CDM-EB74, para 24). It is the discretion of the DNA to decide whether project participants can select between project-specific or standardized baselines. In this regard, the DNA can make their use voluntary or mandatory. This may have two consequences:

  - Standardized baselines open an alternative route towards positive lists (Section 3.7), while keeping the approach of demonstrating additionality through the current means. By definition, this can only increase the number of false positives. Hence, the likelihood for additionality is lower, compared to a situation in which there would be no standardized baselines.

  - The voluntary use of standardized baselines could lead to project developers picking and choosing between baseline emission factors which could result in over-crediting (Table 3-9, bullet point 1). Indeed, Spalding-Fecher & Michaelowa (2013) argue that the CMP should make standardized baselines mandatory.

  The degree of these risks depends on how conservative the standardized baselines are set. The more conservatively that they are set, the lower the risk is. An example of how picking and choosing between project-specific and standardized baselines can undermine environmental integrity is the approved standardized baseline ASB0018 for cook stove projects in Burundi. The approved standardized baseline provides default values for the amount of non-renewable biomass consumed in the baseline (1.5 tonnes per person and year for households in urban areas and 1.1 tonnes per person and year for households in rural areas). However, at the same time, a PoA (9634) is registered in Burundi with project-specific baseline values based on data from a more recent survey. The project-specific baseline is more ambitious (1.21 tonnes per person and year for households in urban areas and 0.83 tonnes per person and year for households in rural areas). Had the standardized baseline been approved prior to the registration of the project, the project could have opted for the less ambitious standardized baseline. At the same time, projects with higher project-specific baseline values could opt for their project-specific baseline and not use the standardized baseline.

- **Quality assurance and quality control (QA/QC) of standardized baselines:** Version 04.0 of the procedure *'Development, revision, clarification and update of standardized baselines'*

(CDM-EB84-A10) sets out how a project developer can submit a proposal for a standardized baseline to the CDM EB following first the approval of the relevant DNA. It is necessary for the project developer to provide a list of documents when submitting a standardized baseline proposal, which includes the Form F-CDM-PSB, supporting documents and an Assessment Report of QA/QC. The CDM EB clarified only in 2015 that DOEs not only need to verify whether the required documents were submitted and that the data were collected according to guidelines for quality assurance and quality control but that they also need to check that the standardized baseline has been calculated in accordance with the relevant standards (CDM-EB85-A10). However, this decision still needs to be adequately reflected in the latest version of the *'CDM validation and verification standard'* (CDM-EB82-A14). Moreover, stakeholders expressed concerns that if the requirements for QA/QC are too stringent, it may prevent the approval of standardized baselines from LDCs (Hermwille et al. 2013). Therefore, the QA/QC Assessment Report is currently not compulsory for countries with 10 or fewer registered CDM projects as of 31 December 2010 for the first 3 submissions (CDM-EB84-A10, Para. 18), even though countries can request financial support from the UNFCCC for the development of Assessment Reports. These exemptions from applying the QA/QC guidelines could undermine the environmental integrity of the CDM.

- **Development of country-specific thresholds:** CMP9 requested the EB *"to prioritise the development of top-down thresholds for baseline and additionality for the underrepresented countries in CDM'"* (CDM-EB82-AA-A10, Para. 3). Many stakeholders regard the currently approved default thresholds for additionality and baseline as *'unattractive'* and *'not suitable'* for specific national/regional/sectoral circumstances (CDM-EB82-AA-A10). However, the adoption of country-specific thresholds could be a difficult process as such thresholds are a policy choice rather than a methodological choice. It is uncertain whether or not the development of country-specific thresholds would undermine the environmental integrity of the CDM. However, it would likely result in the incomparability of emission reductions from different standardized baselines within the same project type or technology.

- **Exclusion or inclusion of CDM facilities in the peer group to determine standardized baselines:** The development of certain standardized baselines relies upon the performance and actual output from the facilities of a sector of the host country. Some of these facilities may already have registered CDM projects (i.e. referred to as CDM facilities) that would have improved performance due to the incentives provided by the CDM. Given that it is difficult to determine the performance and outputs of these facilities in the absence of the CDM, it is necessary to take a decision on whether to include CDM facilities in the calculation of a standardized baseline or not. Exclusion of CDM facilities could undermine the environmental integrity of the CDM (CDM-EB78-AA-A05). As a default all CDM projects need to be included in the respective cohort unless the DNA can demonstrate that the cost of fuels/feedstocks/technologies exceed those of certain comparable projects (CDM-EB79, para 41).

- **Vintage of standardized baselines and static versus dynamic standardized baselines:** Standardized baselines are often constructed based on plants for which the investment decision was taken many years in the past. If a standardized baseline is static and not frequently updated, it can mean that additionality is established and baselines are determined based on a market situation that is ten or twenty years old (i.e. failing to take into account technological breakthroughs). This could result in significant crediting of BAU (Table 3-9, bullet point 2). The high-level CDM Policy Dialogue has therefore recommended that in order to drive technological change, the standardized baseline framework must ensure *"that the focus of incentives constantly shifts to the next generation of technologies"* (CDM Policy Dialogue 2012, p. 6). As a consequence, the current standardized baseline framework specified interim data vintages and update frequencies of 3 years respectively (CDM-EB77-A05). For example, sectors associated with slow dynamic developments in the past may allow for a relaxation in the frequency of updates without compromising the environmental integrity of the CDM.

- **Level of disaggregation:** The level of disaggregation is an important factor to consider in the development of a standardized baseline, which can enable a DNA with limited resources to prioritise which mitigation measures to incentivise within a sector. For example, Hermwille et al. (2013) refer to a case study of the rice mill sector in Cambodia where only a small number of large scale rice mills account for approximately 60% of the total output. Given that the remaining output is provided by thousands of small-scale rice mills with very varied use of technologies that are associated with different emission intensities, it was necessary to disaggregate the standardized baseline on the basis of plant size (i.e. focus standardisation on the large-scale mills). The importance of disaggregation of standardized baselines is further demonstrated in the power sector. If a standardized baseline is based upon the entire power sector of a country, it is likely that the use of renewables and possibly of the most efficient fossil fuel technologies would be encouraged. However, if the standardized baseline was disaggregated further to consider fossil fuel consumption only – different mitigation options such as fossil fuel switching would be encouraged instead (Hermwille et al. 2013). The appropriate level of disaggregation depends very much on the project type and the actual circumstances. With the current approach, DNAs can determine the level of disaggregation, though there is no EB guidance on how the appropriate level can be determined. In addition, such guidance would hardly be compatible with the 'one size fits all' approach pursued in the standardized baseline guidance.

In light of all of these challenges, the implementation of standardized baselines may not be suitable for all sectors, project types or countries. The development of a standardized baseline can achieve the objective of simplification in certain sectors associated with more homogenous products. However, standardized baselines will be more difficult to apply to sectors associated with a range of products and strongly varied circumstances amongst installations. Therefore, it should be carefully checked for which purposes, sectors, project types and baseline emission sources standardized baselines are appropriate. Applying one single approach to establish standardized baselines for different sectors, project types and locations, as currently pursued under the CDM, is likely to undermine the environmental integrity of the CDM. Standardized baselines should be developed from actual projects and reflect the particular circumstances of the sector, project type and location. Once approved within a country or region, standardized baselines need to be mandatory for all new CDM projects to prevent that more CERs are issued as if the standardized baseline was not established (Schneider et al. 2012).

To ensure that the concept of standardized baselines provides what it was established for, particularly *"to reduce transaction costs, … while ensuring environmental integrity"* (UNFCCC 2011c), the EB should review the standardized baseline framework. This review should ensure that

- stringent QA/QC procedures are applied to all standardized baselines,
- all CDM facilities without any exemptions are included in the peer group for the standardized baseline,
- DNAs can build their decision on the appropriate disaggregation level on a clear guidance document which aims to determine the level of disaggregation in a way that covers the mitigation activity of the standardized baseline as accurately as possible and includes as few external factors ('noise') as possible;
- the practice of using the same methodological approach to establish standardized baselines for all the different sectors, project types and locations is replaced by the development

of project-specific standards derived from actual projects and reflect the particular circumstances of the sector, project type and location, and last but not least,
- standardized baselines are mandatory for new projects once they are approved for a country.

If these improvements were introduced, standardized baselines could be a valuable tool to improve the environmental integrity of the CDM while lowering transaction costs.

3.9. Consideration of policies and regulations

The consideration of policies and regulations in demonstrating additionality and establishing emissions baseline has been a controversial issue for project-based mechanisms as the CDM. Policies and regulations adopted by the host country can have a significant impact upon future emission pathways. For example, the introduction of air quality regulations for power plants impacts their CO_2 emissions while fossil fuel subsidies reduce the viability of less emission-intensive technologies (Schneider et al. 2014). When setting the baseline and demonstrating additionality there have been concerns raised about both perverse incentives for policy makers (i.e. host countries not implementing policies and measures that reduce emissions so that they can secure greater carbon revenues) and about environmental integrity, by either over-crediting of emission reductions (i.e. inflating the baseline by excluding polices and measures that reduce emissions) or non-additional projects (i.e. registering projects that are economically viable and do not face barriers by allowing the exclusion of subsidies in the investment analysis).

The modalities and procedures for the CDM require that *"a baseline shall be established taking into account relevant national and/or sectoral policies and circumstances, such as sectoral reform initiatives, local fuel availability, power sector expansion plans, and the economic situation in the project sector"* (decision 3/CMP.1, para 45(e)). However, in order to avoid the creation of perverse incentives for policy makers, the CDM EB adopted, at its 22nd meeting, the following rules with regard to the consideration of policies in setting baselines:

- **E+ policies:** to not consider polices adopted after 1997 which *"give comparative advantages to more emissions intensive technologies or fuels over less emissions intensive technologies or fuels"* in setting the baseline;

- **E- policies:** to not consider policies adopted after 2001 which *"'give comparative advantages to less emissions intensive technologies over more emissions intensive technologies"* in setting the baseline.[42]

These rules failed, however, to fully address perverse incentives for policy makers, as host countries would continue to have incentives to maintain existing E+ policies such as fossil fuel subsidies. Furthermore, although host countries will not be discouraged from implementing national policies and measures that reduce emissions (E- policies), the rules are likely to result in over-crediting of emission reductions.

Overall, in the case of E- policies it seems difficult to reconcile the two policy objectives: avoiding perverse incentives for policy makers and ensuring environmental integrity. If E- policies were excluded when demonstrating additionality or setting baselines, perverse incentives would be addressed but environmental integrity would be undermined, since projects that are financially viable could claim they are not, and emissions baselines would be inflated. If E- policies were included, environmental integrity would be ensured but perverse incentives not addressed.

[42] EB 22 report, Annex 3: Clarifications on the consideration of national and/or sectoral policies and circumstances in baseline Scenarios (Version 02), https://cdm.unfccc.int/EB/022/eb22_repan3.pdf.

In 2013, the EB reviewed its E- policy guidelines with a view to balancing these two conflicting policy objectives and *"agreed to pursue an approach by which, for the first seven years from the effective implementation date of the relevant E- policy, the benefit of that E- policy does not need to be considered by project participants in the additionality demonstration through investment analysis"* (CDM-EB73, para. 70). The approach would thus ignore new E- policies but for a limited time period. Initially allowing the exclusion of E- policies could be seen as addressing perverse incentives for policy makers, while ensuring environmental integrity in the longer term. It would also expand the approach of ignoring E- policies from baseline setting to demonstrating additionality. However, the EB has not yet been able to agree on a revision of its E+/- policy guidelines.

Based upon an econometric analysis, Lui (2014) raises questions about the decline of feed-in tariffs in China[43] that may imply a gaming to ensure wind projects are not economically attractive for the purpose of demonstrating additionality under the CDM. Schneider et al. (2014) argue that with regards to E- policies it is simply not feasible to achieve both a robust crediting baseline and avoid the creation of perverse incentives at the same time. Striking a balance between the two objectives is therefore required when setting the crediting baseline, which is likely to vary depending upon the sector, project type and type of policy.

Given the contrasting objectives, the decision on whether to include E- policies in the baseline or not and the determination of additionality of a project-based mitigation activity should depend upon the potential risk of either creating perverse incentives or over-crediting. Schneider et al. (2014) recommend that the following approach should be pursued when setting baselines and determining additionality:

- If the **risk of creating perverse incentives** is judged to be considerably larger than the risk of over-crediting, then E- policies should not be considered (for a certain period) in setting the baseline;
- If the **risk of over-crediting** is deemed to be considerably greater than the risk of creating perverse incentives, then E- policies should be considered in setting the baseline.

The extent to which the setting of baseline and determination of additionality for a project-based mitigation activity is more liable to either the risks of perverse incentives or over-crediting depends upon the wider co-benefits associated with a policy other than simply climate change mitigation. For example, the deployment of renewables is associated with multiple co-benefits such as employment opportunities, energy security and air quality improvements. Given the additional benefits associated with such E- policies, it is less likely that these policies would not be adopted as a consequence of changes to an international crediting mechanism. Schneider et al. (2014) and Spalding-Fecher (2013) therefore both argue that the risk of creating perverse incentives (i.e. delaying policies and regulations to secure more CER revenues) may be lower than the risks of setting a less robust baseline (i.e. by not including E- policies in the baseline) that leads to the over-crediting of emission reductions. Spalding-Fecher (2013) also points out that such co-benefits are likely to occur with electricity generation, energy efficiency and agriculture projects.

However, the risk of creating perverse incentives is likely to be greater from mitigation activities such as the capture of HFC-23, which reduce GHG emissions but do not lead to significant co-benefits. In such a case, preventing the creation of perverse incentives (i.e. host country delaying regulation on the capture of HFC-23) could be given priority over additionality and environmental integrity by not considering such E- policies when setting the baseline. Nevertheless, CERs resulting from such projects would be used to offset GHG emissions in other capped systems and, since

[43] Spalding-Fecher (2013) discusses the uncertainty within the CDM EB on how such a policy change should be classified under the E+/- policy guidance.

they are not truly additional, result in globally higher emissions. Therefore, it would be more appropriate to support such technologies by other means such as ODA or climate finance or by addressing these mitigation potentials as own contribution under the ADP negotiations.

From a more practical perspective, Spalding-Fecher (2013) emphasises the difficulty of accurately accounting for the effects of E- policies when setting either the baseline or demonstrating additionality. The level of difficulty depends upon the policy type. For example, the impact of direct financial incentives such as mandatory feed-in tariffs can be removed more easily from an emissions baseline than indirect sectoral incentives such as renewable energy portfolio standards or economy-wide policies such as domestic emissions trading schemes. Furthermore, defining the date of policy implementation and the effectiveness of enforcement may sometimes represent additional challenges (Spalding-Fecher 2013). If the guidance provided by the CDM EB – given the difficulty in isolating the impact of multiple (and sometimes conflicting) policies when setting emission baselines or demonstrating additionality – would only relate to direct financial incentives this could lead to the unequal treatment of host countries under the CDM based upon the types of policies implemented (Spalding-Fecher 2013). For example, it would be easier to determine the additionality of a renewable energy project in a host country with direct financial incentives such as feed-in tariffs compared to a host country that adopted a domestic emissions trading scheme. This practical problem could not only undermine the environmental integrity of the CDM but also mean that excluding E+ or E- policies may simply not be practical.

Taking into account the various challenges to strike the right balance between avoiding perverse incentives for policy makers and ensuring environmental integrity, Spalding-Fecher (2013) concludes that the risk of perverse incentives is not as high as previously assumed in many countries and sectors, while the risk of over-crediting is substantial. He therefore suggests that as a general rule all E- policies should be considered in both baseline-setting and additionality determination. Schneider et al. (2014) outline the following options in relation to E- policies:[44]

- No consideration of E- policies: No perverse incentives would be created if both existing and planned E- policies were not considered when setting the crediting baseline. In fact, host countries would be encouraged to introduce further E- policies to further reduce emissions below the baseline. However, the disadvantage of this option would be that the emission baseline would most likely be inflated above BAU.
- Consideration of existing E- policies, exclusion of future E- policies: A more balanced approach could involve the introduction of a cut-off date for excluding future E- policies from being considered in the setting of the crediting baseline. However the setting of a cut-off date is problematic. For example, if the cut-off point is set too early it may inflate the crediting baseline by considering E- policies that have already been adopted. Nevertheless, the option provides a positive incentive for host countries to adopt new E- policies (after the cut-off point) to reduce emissions.
- Consideration of existing and future E- policies: A robust crediting baseline would be established if both existing and future E- policies were considered (either ex-ante or ex-post), however this would most likely create disincentives to introduce E- policies as their introduction could lower the potential for credits. In addition, this option would provide greater uncertainty for investors as to when a crediting baseline would be updated.

In order to prevent the over-crediting of emission reductions, it would be a sensible approach to include current E- policies in the crediting baseline. However, accounting for future E- policies is

[44] These options are outlined in the context of a sector based crediting mechanism though they also apply to the CDM.

more problematic and warrants further research to ensure that a reasonable balance is achieved between limiting the over-crediting of emission reductions and preventing the creation of perverse incentives. Schneider et al. (2014) and Spalding-Fecher (2013) conclude that the balance should be more in favour of limiting over-crediting in the CDM or future mechanisms as they judge this risk to be greater to undermining environment integrity than from the creation of perverse incentives. Therefore, as a general rule Schneider et al. (2014) recommend that adopted policies and regulations reducing GHG emissions should be included when setting crediting baselines and policies that increase GHG emissions should be discouraged by their exclusion from the crediting baseline where possible.

3.10. Suppressed demand

One of the challenges of applying GHG accounting approaches in poor communities is that the current consumption of many household services (e.g. heating and cooking energy, lighting and potable water) may not reflect the real demand for those services. This could be a result of lack of infrastructure, lack of natural resources or poverty, particularly the high costs of these services relative to household incomes. The situation of 'suppressed demand' creates a problem for setting baselines, because the CDM rules say that the baseline scenario selected for a project should provide the same level of service and quality as the project scenario (Gavaldão et al. 2012; Michaelowa et al. 2014; Spalding-Fecher 2015; Winkler & Thorne 2002). This is clearly not the case if the project scenario provides a much higher service level, owing to low historical consumption. At the same time, the CDM rules state that "the baseline may include a scenario in which future anthropogenic emissions by sources are projected to rise above current levels, due to the specific circumstances of the host Party" (UNFCCC 2006a para. 46). This section analyzes how the concept of suppressed demand has been implemented in CDM methodologies and what the potential impacts on CER issuance as a result of the revised and new methodologies. For a more detailed conceptual explanation of suppressed demand, as well as background on previous EB decisions and guidance, see Chapter 9 of Spalding-Fecher et al. (2012).

3.10.1. Treatment of suppressed demand in approved methodologies

Table 3-10 below shows the methodologies in which suppressed demand has been explicitly considered, in three different categories. The first group is from a work plan agreed by the EB at their 67th meeting, when the EB requested that the Secretariat and relevant support panels explore how to incorporate suppressed demand. The second group is methodology revisions for which the proponent of the revision motivated the change based on the Suppressed Demand guidance. The final group is new methodologies that were developed after the approvals of the Suppressed Demand guidance and incorporated those ideas, as documented in the UNFCCC Methodology Guidebook. Of the original 10 methodologies in the EB work plan, 5 were revised or replaced, while an additional 8 methodologies fall into the second and third categories.

Note that a group of methodologies not listed here, but that implicitly recognise suppressed demand, are those addressing new large-scale power generation or industrial development. New renewable energy, natural gas or high-efficiency coal power plants are not required to show that they actually replace an existing power plant. Given that most developing countries have shortages in power supply, building a new natural-gas-fired power plant, for example, could potentially increase emissions compared to current levels. However, the accepted principle on baseline development across the CDM is that the baseline is not necessarily the same as historical emissions, but should reflect the most likely development scenario for the sector. Even in countries with chronic power shortages, it would be difficult to argue that there would be *no* capacity increases under the baseline scenario. This means that, even in these cases, CDM projects – if properly justified –

would potentially displace another alternative new plant. The determination of the alternative plant is then the subject of the methodology's baseline scenario analysis.

Table 3-10: Methodologies explicitly addressing suppressed demand or part of EB work plan on suppressed demand

Meth No.	Meth Name	Re-vised?	When	Pipeline[1]	
				Pro-jects	PoAs
From EB67 work plan List of Methodologies					
AM0025	Alternative waste treatment processes	ACM22	EB69	127	5
AM0046	Distribution of efficient light bulbs to households	No		2	0
AM0086	Installation of zero energy water purifier for safe drinking water application	No	EB70	1	0
AM0094	Distribution of biomass based stove and/or heater for house-hold or institution	No	EB70	0	0
ACM0014	Treatment of wastewater	Yes	EB77	47	1
ACM0016	Mass Rapid Transit Projects	No		16	1
AMS I.A	Electricity generation by the user	Yes	EB69	50	17
AMS I.E	Switch from non-renewable biomass for thermal applications by the user	Not nec-essary	EB70	24	58
AMS II.E	Energy efficiency and fuel switching measures for buildings	No		44	5
AMS III.AR	Substituting fossil fuel based lighting with LED/CFL lighting systems	Yes	EB68	4	14
Additional revisions referring to Suppressed Demand					
AM0091	Energy efficiency technologies and fuel switching in new and existing buildings	Yes	EB77	0	0
AMS II.G	Energy efficiency measures in thermal applications of non-renewable biomass	Yes	EB70	45	62
AMS III.F	Avoidance of methane emissions through composting	Yes	EB67	103	20
New methodologies where EB noted Suppressed Demand					
ACM0022	Alternative waste treatment processes	New	EB69	10	0
AMS II.R	Energy efficiency space heating measures for residential buildings	New	EB73	0	0
AMS I.L	Electrification of rural communities using renewable energy	New	EB66	0	1
AMS III.BB	Electrification of communities through grid extension or new mini-grids	New	EB67	0	0
AMS III.AV	Low greenhouse gas emitting safe drinking water production systems	New	EB60/62	0	10
Total with revisions or new related to suppressed demand				**473**	**194**
Total pipeline				**11,990**	**446**[2]

Notes: [1] Pipeline is as of 1 January 2014. [2] PoA DD's submitted, which may include multiple methodologies and include 23 PoAs replaced by new versions. Total number of methodology citations in all PoAs submitted is 874.

Sources: Authors' own compilation

While the proportion of project activities influenced by these methodologies is very small, a significant share of PoAs are utilising the revised or new methodologies. In terms of the quantitative impact of the revisions to methodologies to incorporate suppressed demand; however, this may only relate to projects or PoAs entering the pipeline after the revision. While project participants are allowed to update the version of the methodology that they use prior to the renewal of the crediting period, this should not make the emission reduction calculations less conservative. Given that the suppressed demand revisions could increase the baseline significantly, it is not entirely clear whether the EB would approve this revision for existing projects prior to the renewable of the crediting period (when the latest version of the methodology must be used). Because AM00025 was replaced by ACM0022 in order to address suppressed demand, none of the projects or PoAs under AM0025 (which was not used after October 2012) would be able to utilise the new suppressed demand approach embodied in ACM0022. Table 3-11 below shows the number of PoAs and Projects in the pipeline both before and after the revisions.

Table 3-11: CDM pipeline affected by suppressed demand methodologies

Meth No.	Meth Name	Total pipeline		New pipeline since revision	
		Projects	PoAs	Projects	PoAs
Revised methodologies					
ACM0014	Treatment of wastewater	47	1	0	0
AMS I.A	Electricity generation by the user	50	17	0	13
AMS III.AR	Substituting fossil fuel based lighting with LED/CFL lighting systems	4	14	3	1
AM0091	Energy efficiency technologies and fuel switching in new and existing buildings	0	0	0	0
AMS II.G	Energy efficiency measures in thermal applications of non-renewable biomass	45	62	2	18
AMS III.F	Avoidance of methane emissions through composting	103	20	7	8
New methodologies that incorporate suppressed demand					
AMS I.E	Switch from non-renewable biomass for thermal applications by the user	24	58	24	58
ACM0022	Alternative waste treatment processes	10	0	10	0
AMS II.R	Energy efficiency space heating measures for residential buildings	0	0	0	0
AMS I.L	Electrification of rural communities using renewable energy	0	1	0	1
AMS III.BB	Electrification of communities through grid extension or construction of new mini-grids	0	0	0	0
AMS III.AV	Low greenhouse gas emitting safe drinking water production systems	0	10	0	10
Total		**283**	**183**	**46**	**109**

Sources: Authors' own compilation

How the suppressed demand concepts and guidance are implemented varies significantly by methodology. With the exception of AMS III.AR, all of the methodologies use the project activity level as the baseline activity level. Only AMS III.AR defines a quantitative Minimum Service Level that is used to calculate baseline emissions. AMS I.L and AMS III.BB define an MSL, but it is only used to adjust the emissions factor for the baseline, rather than to directly calculate baseline activity levels or emissions. For AMS III.F and ACM0022, the minimum service level is qualitatively defined as having a solid waste disposal site (i.e. rather than considering the quantity of waste processed per household). What the methodologies all do, however, is to define a baseline technology that may have higher emissions than the actual current technology. For example, households may currently only use candles and kerosene hurricane lamps, and therefore have very low lighting services, but the methodologies use a kerosene pressure lamps for the baseline technology, because this can deliver the MSL for lighting services.

For the revised methodologies, the resulting baselines emissions could be substantially higher per household (Annex 8.2, Table 8-1). For example, under ACM0014, baseline methane emissions may still be considered even if the wastewater is currently not treated or stored in a way that would necessarily produce emissions (e.g. lagoons with depth less than 1 m). ACM0022 and AMS III.F have emissions factors that could be double the current practices, while for AMS I.L and AMS

III.BB, the emission factor for very small users (e.g. 50 kWh/yr) is almost 7 times the emissions factor originally used in AMS I.A for these projects.

3.10.2. Impact on CER supply

If current energy service demand is suppressed by lack of income, relatively high energy prices and/or lack of physical access, how quickly might this change without the CDM project? In other words, how long might it take for the current emissions to reach the suppressed baseline emissions? This depends on many factors, including income growth in the host communities and changes in access. Data from the World Bank's World Development Indicators (World Bank 2014), for example, shows that, at a highly aggregated level, per capita incomes in most developing regions have, indeed, increased substantially, but this is slower in low income countries. Electricity consumption per capita, however, has not shown such consistent growth in Africa, largely due to population growth outstripping energy supply growth and electrification programmes (World Bank 2014). This data cannot necessarily be applied to specific sub-regions or project areas, but does show that significant increases in energy consumption are possible in a relatively short time frame. In terms of electrification rates, these have increased relatively rapidly for key countries, rising from 25% or 30% to 60% to 80% in as little as 10 or as many as 30 years (Bazilian et al. 2011). Clearly, the level at which the minimum service level is set will also influence the risk of over-crediting, with lower service levels being more likely to reflect potential consumption in the shorter term without the CDM.

Even if the households were not to reach the minimum service levels in the near term and the emissions factors used in these methodologies is substantially higher than in traditional methodologies, the overall impact on CER generation is likely to be very small. The total CERs projected to 2020 for the methodologies in Table 3-11 after the revisions to those methodologies is approximately 17 million. Even if all of the CERs for those methodologies are considered (i.e. before and after revision), at approximately 112 million, this is still less than 1% of the entire CDM pipeline, and so does not represent a significant impact on emissions.

3.10.3. Additionality concerns

In summary, while the introduction of the concept of suppressed demand in CDM methodologies is expanding, and will have important development impacts, it is unlikely to have a major impact on the overall additionality of CDM projects. In many project areas, it is likely that the communities could reach the Minimum Service Levels during the course of the CDM project life, although this is uncertain and will depend on local circumstances. Creating an open and transparent process of setting minimum service levels, with expert input as well as input from other stakeholders, could also help 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 certain country groups (e.g. LDCs, under-represented countries), in which development needs are highest and the potential for over-crediting it the smallest. Even if the suppressed demand does lead to some over-crediting, the overall impact is very small, particularly if restricted geographically. More importantly, the increased contribution to sustainable development provides a strong justification for this approach to project types that address poverty and development issues.

4. Assessment of specific CDM project types

The relevant literature highlights that the likelihood of CERs representing real, measurable and additional emission reductions varies considerably among project types. Some project types do not generate revenues other than CERs. These projects have a high likelihood of being additional. Other project types are heavily promoted and/or subsidized by governments, generate significant other revenues, or their economic feasibility is hardly impacted by CER revenues. For these projects, additionality is more questionable.

Other aspects affecting the quality of CERs also vary among project types. Perverse incentives are particularly relevant for projects that generate large CER revenues compared to the cost structure of their main business (e.g. HFC-23 projects). Baselines are particularly challenging to determine in dynamic sectors with high rates of learning and innovation and penetration of new technologies over relatively short periods of time. The length of crediting is critical for project types which are implemented earlier due to the CDM incentives.

For these reasons, this chapter evaluates the ability to deliver real, measurable and additional emissions reductions for specific CDM project types. In the following, we select important project types in Section 4.1 and assess these project types in the subsequent sections.

4.1. Project types selected for evaluation

We select the project types for evaluation mostly based on their potential CER volume in the period of 2013 to 2020 according to the current CDM project portfolio. Focusing on the period of 2013 to 2020 and on the largest CDM project types in terms of potential CER volume allows the best estimation of the quality of the overall CDM project portfolio for future new demand for CERs. Moreover, the project types with the largest market share are most critical for the overall quality of the CDM.

The specific project types selected for evaluation are provided in Table 4-1. The table also shows that these project types cover a potential CER volume of 4.8 billion CERs, which corresponds to 85% of the overall CER supply potential for the period of 2013 to 2020 (Section 2.3). This ensures a large representativeness.

Table 4-1: Project types selected for evaluation

Project type	Potential CER supply 2013 to 2020 [million]	Focus areas analyzed
Wind power	1,397	Additionality, baselines
Hydropower	1,669	Additionality, baselines
Biomass power	162	Additionality, baselines, leakage
HFC-23	375	Perverse incentive, baselines
Adipic acid	257	Perverse incentives (leakage)
Nitric acid	175	Perverse incentives, baselines
Landfill gas	163	Additionality, baselines, perverse incentives
Coal mine methane	170	Additionality, baselines
Waste heat recovery	222	Additionality, baselines
Fossil fuel switch	232	Additionality, baselines
Efficient cook stoves	2.3	Additionality, baselines
Efficient lighting	3.8	Additionality
Total of all selected project types	**4,829**	
Total of all projects in the CDM portfolio	**5,671**	

Source: Authors' own compilation and calculations

4.2. HFC-23 abatement from HCFC-22 production

4.2.1. Overview

Hydrofluorocarbon-23 (HFC-23) is a waste gas from the production of hydrochlorofluorocarbon-22 (HCFC-22), which is a GHG and an ozone-depleting substance (ODS) regulated under the Montreal Protocol on Substances that Deplete the Ozone Layer. HCFCs were introduced as an alternative to the highly ozone-depleting chloro-fluorocarbons (CFCs) because of their lower ozone-depleting potential. HCFC-22 is mainly used for two purposes: as a refrigerant in refrigeration and air-conditioning appliances and as a feedstock in the production of polytetrafluoroethylene (PTFE). The production for the refrigeration and air-conditioning industry is regulated under the Montreal Protocol, whereas the production for feedstock purposes is not.

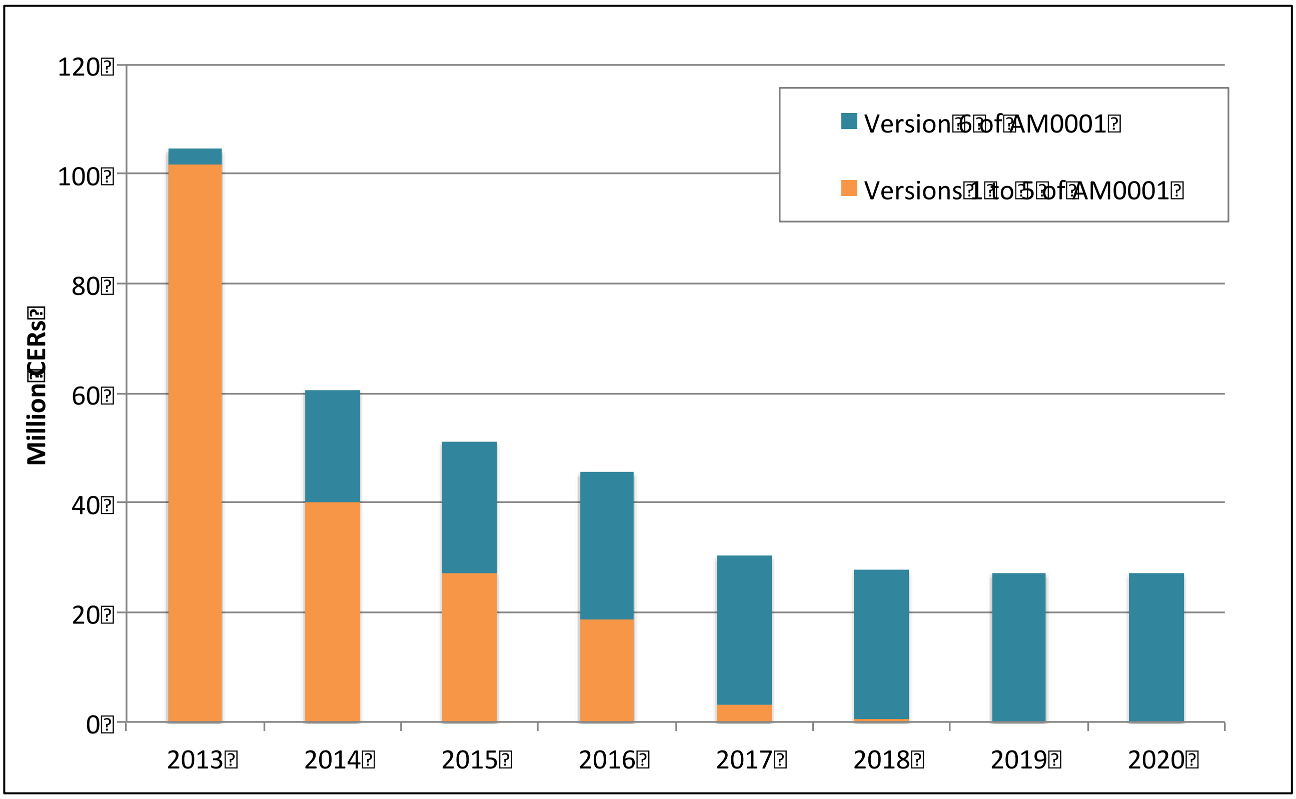
HFC-23 is a potent greenhouse gas; its global warming potential (GWP) is estimated at 14,800 for the second commitment period of the Kyoto Protocol. Emissions of HFC-23 from HCFC-22 production can be abated in two ways: a) by reducing the rate of waste gas generation (by-product rate) through process optimization and b) by capturing and destroying HFC-23 through installation and operation of high temperature incinerators. In the absence of regulations, incentives, or voluntary commitments by the industry, HFC-23 is usually vented to the atmosphere (Schneider & Cames 2014).

4.2.2. Potential CER volume

Under the CDM, 19 HFC-23 projects have been registered. Eleven projects are located in China, five in India; South Korea, Argentina and Mexico each host one project. All projects apply the baseline and monitoring methodology AM0001. In the first commitment period of the Kyoto Protocol, the abatement of HFC-23 has been the project type with the largest CER issuance: 516 million HFC-

23 CERs or 36% were issued of a total of 1.4 billion CERs by the end of 2013. The potential CER supply for the period of 2013 to 2020 is estimated using a bottom-up model based on a detailed evaluation of the information in PDDs and monitoring reports from all 19 projects (Schneider & Cames 2014). In estimating the potential CER supply we differentiate between CERs from the application of versions 1 to 5 and version 6 of the applicable baseline and monitoring methodology AM0001 due to the significant differences between these methodology versions. The potential CER supply for the period of 2013 to 2020 is illustrated in Figure 4-1; it amounts to approx. 375 million CERs for the entire period, with 191 million from the application of version 1 to 5 and 184 million from the application of version 6 of the methodology AM0001.

Figure 4-1: CER supply potential of HFC-23 projects



Sources: Authors' own compilation

4.2.3. Additionality

All versions of the applicable baseline and monitoring methodology AM0001 consider HFC-23 projects to be automatically additional, as long as no regulations to abate HFC-23 are in place in the host country. This rule seems appropriate. Prior to the CDM, none of the plants in developing countries had equipment to destruct destroy HFC-23; HFC-23 generated in the production process was vented to the atmosphere. The same holds for plants that are not eligible for crediting under the CDM because they started commercial operation after 31 December 2001. Plant operators do not have economic incentives to install HFC-23 destruction equipment, as the installation and operation does not reduce costs or generate any significant revenues other than from CERs.[45] Based on these considerations, we assess that this project type is very likely to be additional.

[45] Schneider & Cames (2014) report that plant operators could sell HF which is a by-product from flue gas treatment. However, these revenues are likely lower than the costs for HFC-23 destruction.

4.2.4. Baseline emissions

HFC-23 generation from HCFC-22 production depends on two factors: the amount of HCFC-22 production and the ratio between HFC-23 generation and HCFC-22 production, which is often referred to as 'waste generation rate'. The applicable methodology AM0001 determines baseline emissions of HFC-23 based on these two factors, by multiplying the baseline HCFC-22 production with the baseline waste generation rate.[46] How these two parameters are calculated, has evolved over time.

The approaches changed over time with a view to addressing perverse incentives which are a particular concern for the crediting of HFC-23, due to the low technical abatement costs[47] and significant profits which can accrue from CER revenues and could exceed the costs of HCFC-22 production (Schneider 2011, UNFCCC 2011b, TEAP 2005). Significant perverse incentives were observed in two JI projects in which plant operators increased the waste generation rate to unprecedented levels once methodological safeguards were abandoned (Schneider & Kollmuss 2015). Perverse incentives can arise from the CDM in the following ways:

- HCFC-22 plants could operate at a higher waste generation rate than they would in the absence of the CER revenues, leading to over-crediting;
- The amount of HCFC-22 produced at CDM plants could be higher than in the absence of the CER revenues. This could lead to over-crediting if
  - HCFC-22 production is displaced at non-CDM plants that have a lower waste generation rate than the baseline rate used at the CDM plants;
  - HCFC-22 production is displaced at plants located in Annex I countries that already are required to abate HFC-23 emissions;
  - HCFC-22 is not produced for use in applications but is vented to the atmosphere;
  - The use of HCFC-22 becomes economically more attractive due to the CDM and is increasingly used compared to other less GHG-intensive alternatives;
  - The base year emissions (2009-2010) under the accelerated phase-out under the 2007 amendment to the Montreal Protocol are higher due to the CDM;
  - The implementation of the accelerated phase-out of HCFC-22 is delayed due to the CDM.
- The HCFC-22 plants could operate longer than they would in the absence of CDM revenues. This could lead to over-crediting under the same circumstances as a higher HCFC-22 production at the plants.

Robustness and conservativeness of the methodology has significantly increased over time. Perverse incentives constitute a major challenge in versions 1 to 5, whereas the conservative approach in version 6 largely avoids and compensates for perverse incentives.

For CERs issued to projects under versions 1 to 5, the amount of over-crediting is uncertain, since it hinges strongly on assumptions on HCFC-22 production levels, HFC-23 waste generation rates and the indirect effects noted above. Munnings et al. (2016) suggest that under-crediting due to conservative baselines may have more than compensated for the potential over-crediting from perverse incentives that these baselines were intended to curb. However, Munnings et al. (2016) make several assumptions that seem rather implausible. For example, they assume that in the absence of the CDM, some plants would have produced more HCFC-22 than they did under the CDM. As a result, we do not find their arguments persuasive.

[46] Versions 1 to 5 of methodology AM0001 do not explicitly calculate baseline emissions but directly calculate the emission reductions.
[47] Schneider & Cames (2014), Appendix, provide an overview of technical abatement costs for HFC-23 destruction.

Under version 6, on the other hand, net under-crediting (or net emissions benefit) is very likely since the methodology uses an ambitious default value of 1.0% for the baseline waste generation rate and caps the amount of HCFC-22 production that is eligible for crediting in a more conservative manner (Erickson et al. 2014). However, as of 1 January 2016, no credits have been issued under version 6.

4.2.5. Other issues

Continued low CER prices could jeopardize continued abatement activities at CDM HFC-23 project sites, an unfortunate outcome given the very inexpensive abatement opportunities they provide. At the same time, the failure of the CDM market to ensure continued abatement creates the opportunity for other policies that could yield even greater net emission benefits, especially if no credits are generated that could be also used to increase emissions elsewhere. For example, China recently launched a results-based finance programme that supports HFC-23 abatement in CDM and non-CDM plants (NDRC 2015). This programme helps support HFC-23 abatement across the sector in China. However, continued abatement in other CDM-eligible countries is less certain.

There are also other means to ensure these important abatement opportunities are not lost. Emissions of HFC-23 from HCFC-22 production can be regulated through the Montreal Protocol and for new facilities that have not yet installed GHG abatement, the Protocol's Multilateral Fund (MLF) for GHG abatement can provide financial support (Schneider & Cames 2014).

Note also that continued crediting under the CDM could also create perverse incentives for policy makers not to pursue alternative policies such as these, which address emissions without yielding CERs.

4.2.6. Summary of findings

Past changes to methodologies have now improved the integrity of these projects. If they are operated they are likely to yield more emissions reductions than CERs – i.e. a net mitigation benefit. However, continued low CER prices jeopardize their continued operation in some countries.

Additionality	• Likely to be additional
Over-crediting	• Risk of perverse incentives largely addressed in most recent methodology (version 6). • Version 6 could lead to under-crediting (net mitigation benefit)
Other issues	• Low CER prices jeopardizes continued operation • Emissions could be addressed through Montreal Protocol • Perverse incentives to avoid domestic regulation

4.2.7. Recommendations for reform of CDM rules

The necessary changes in AM0001 have been implemented in recent years. No changes in CDM rules are needed.

4.3. Adipic acid

4.3.1. Overview

Adipic acid is an organic chemical that is used as a building block in a range of different products, most importantly polyamide, often referred to as 'nylon'. Other applications include the production of polyurethanes and plasticizers. Adipic acid is a globally traded commodity, with more than one-third of the production traded internationally. Nitrous oxide (N_2O) is an unwanted by-product of adipic acid production. The formation of N_2O cannot be avoided; it is the result of using nitric acid to oxidize cyclohexanone and/or cyclohexanol. Generally, the amount of N_2O generated varies very little over time and among plants.

N_2O in the waste gas stream can be abated in different ways: by catalytic destruction, by thermal decomposition, by using the N_2O for nitric acid production, or by recycling the N_2O as feedstock for adipic acid production (Schneider, L. et al. 2010). These methods typically reach an abatement level of about 90% (IPCC 2006, p. 3.30, Ecofys et al. 2009, p. 44). However, plants implemented under CDM and JI achieved significantly higher abatement levels of approx. 99% in the case of CDM and 92% to 99% in the case of JI, apparently through the strong economic incentives from the CDM and JI (Schneider, L. et al. 2010).

4.3.2. Potential CER volume

Under the CDM, four projects were registered. Two projects are located in China, one is in Brazil and one in South Korea. All four CDM plants had no abatement installed before project implementation and applied either thermal or catalytic abatement. The four implemented CDM plants cover only a part of the adipic acid production in developing countries because the applicable CDM methodology AM0021 is limited to plants that started commercial operation before 2005. Since then, five new plants are known to have started commercial operation in China; none of them abates N_2O emissions (Schneider & Cames 2014). Based on a bottom-up model used by Schneider & Cames (2014), the four CDM projects could generate about 257 million CERs in the period of 2013 to 2020.

4.3.3. Additionality

The applicable methodology AM0021 combines the approaches included in the different approaches to demonstrate additionality. Version 1 establishes three criteria for additionality demonstration: no regulations should require N_2O abatement, the project should not be common practice and it should not be economically viable. Versions 2 and 3 refer to the additionality tool and hence the investment analysis is not mandatory for additionality demonstration, as compared to version 1. Nevertheless, all four registered projects conduct an investment analysis and determine the net present value (NPV). Versions 2 and 3 also require reassessment of additionality during the crediting period if new NO_X regulations were introduced.

N_2O abatement from adipic acid production can be regarded as highly likely to be additional, for several reasons. Firstly, none of the non-Annex I countries in which adipic acid is produced have regulations in place to abate N_2O. Secondly, for thermal or catalytic destruction of N_2O, plant operators have no economic incentives to abate N_2O emissions. The abatement generates steam as a by-product; however, the cost savings or revenues are lower than the investment and operation and maintenance costs. Based on a review of PDDs and literature information, the technical abatement costs are estimated at €0.3/t CO_2e, with a range from €0.1/t CO_2e to €1.2/t CO_2e (Schneider & Cames 2014).

Thirdly, the abatement of N_2O from adipic acid production is not common practice in non-Annex I countries. In Western industrialized countries, N_2O has been abated voluntarily since the 1990s. In non-Annex I countries, only one plant in Singapore had abatement technology installed prior to the CDM (Schneider, L. et al. 2010). None of the plants commissioned after 2004, which are not eligible for crediting under the CDM, installed N_2O abatement technology.

4.3.4. Baseline emissions

Baseline emissions of N_2O are determined by multiplying the amount of adipic acid production eligible for crediting with a baseline emission factor. The methodology further estimates baseline emissions from steam generated during the catalytic or thermal destruction of N_2O. Baseline emissions from steam generation are very small compared to baseline emissions of N_2O.

The baseline emission factor is determined as the lower value between the actual rate of N_2O formation and a default value of 270 kg N_2O / t adipic acid, which corresponds to the lower end of the uncertainty range of the IPCC default value of 300 kg / t adipic acid (IPCC 2006). This approach is used in all three methodology versions and intends to exclude the possibility of manipulating the production process to increase the rate of N_2O formation. Versions 2 and 3 require the actual N_2O formation rate to be determined in two ways: 1) based on the consumption of nitric acid and the ratio of N_2O to N_2 in the off-gas, and 2) based on direct measurements of N_2O in the off-gas adjusted by a 5% discount factor to account for measurement uncertainty. As a conservative approach, the lower resulting value of the two ways is used to determine the baseline emission factor. Overall, the methodology ensures that the baseline emission factor is determined in a conservative manner. The rate of N_2O formation typically observed is higher than the default value of 270 kg / t adipic acid, which could potentially lead to under-crediting of few percentage points.

The amount of adipic acid production that is eligible for crediting is capped in all three methodology versions with a view to avoiding incentives to expand the production as a result of the CDM. Version 2 and 3 establish the cap as the highest annual production in the three years prior to the implementation of the project activity. Version 1 does not provide a procedure to determine a cap but specifies that the methodology is “only applicable for installed capacity (measured in tons of adipic acid per year) that exists by the end of the year 2004”. There has been controversy about how this requirement is to be interpreted. Following a request for clarification (AM_CLA_0148), the Methodologies Panel recommended using production data from three historical years, similar to Versions 2 and 3. However, the CDM EB concluded that the panels' clarification “provides too extensive interpretation to an older version of methodology” and clarified instead that the cap should be determined as the “validated maximum daily production of adipic acid multiplied by 365 days multiplied by the operational rate”.[48] This was further interpreted in a way that allowed plants to seek credits beyond their annual design capacity specified in PDDs. All four CDM projects were registered with Version 1 of the methodology. Two projects (0099 and 0116) recently renewed their crediting period, applying Version 3 of the methodology, which lead to caps that that are 14.8% and 13.9% lower than the caps applicable in their first crediting period.

While the methodology intended to avoid production shifts through caps on the amount of production that is eligible for crediting, data on adipic acid production, plant utilisation and international trade patterns suggest that carbon leakage, i.e. a shift of production from non-CDM plants to CDM plants, occurred during the economic downturn in 2008 and 2009 (Schneider, L. et al. 2010). Such production shifts do not only lead to distortions in the adipic acid market but can also lead to over-crediting if N_2O is abated in the non-CDM plants. Schneider, L. et al. (2010) estimate that carbon leakage leads to over-crediting of approx. 6.3 $MtCO_2e$ or about 17% of the CERs from adipic acid projects issued in 2008 and approx. 7.2 $MtCO_2e$ or about 21% of the CERs from adipic acid projects in 2009. These effects could thus outweigh the conservative determination of the baseline emission factor.

The lenient interpretation of historical production capacity in version 1 of the methodology considerably contributed to the carbon leakage. However, the more conservative approach for the establishment of the cap on adipic acid production in versions 2 and 3 of the methodology addresses this issue only partially. In a global economic recession, adipic acid production could fall well below historical rates of plant utilisation. Depending on the CER prices, CDM plants operators would then have significant competitive advantage over non-CDM plants, which could lead to similar produc-

[48] Report of the 48th meeting of the EB, paragraph 24.

tion shifts as observed in 2008 and 2009. As for HCFC-22 production, the underlying issue is that carbon market revenues can have a strong impact on adipic acid production costs. Carbon leakage is unlikely to occur at current market prices for CERs, but could become an issue again if CER prices increased.

4.3.5. Other issues

No other issues were identified.

4.3.6. Summary of findings

Adipic acid projects have a very high likelihood of additionality. The baseline emission factor is determined in a conservative manner that could lead to a few percentage points of under-crediting. The methodology does not include sufficient provisions to address carbon leakage. This could lead to significant over-crediting in times of higher CERs prices and when the adipic acid production capacity significantly exceeds demand.

Additio-nality	• Likely to be additional
Over-crediting	• Most recent methodology could lead to slight under-crediting • Leakage could lead to significant over-crediting in times of higher CER prices
Other issues	• None

4.3.7. Recommendations for reform of CDM rules

Based on the considerations above, we recommend revising the applicable CDM methodology as follows:

- The provisions for additionality demonstration could be simplified, as this project type can be considered to be very likely additional. We recommend considering this project type as automatically additional, as long as no regulations require N_2O abatement.
- The potential for carbon leakage should be addressed. We recommend introducing a standardized ambitious emission benchmark to determine baseline emissions. Carbon leakage would be avoided most effectively if a consistent emissions benchmark is used for all plants around the world, including plants under ETSs, and if it is set at or below the abatement level typically achieved in the industry. A standardized global emission benchmark for all adipic acid plants, regardless of policy approach or specific emission trading mechanism, could provide a level playing field for the adipic acid industry and eliminate potential economic distortions. Adipic acid production is particularly amenable to a standardized global benchmark because it is a highly globalized industry, and all plants are very similar in structure and technology (Schneider, L. et al. 2010). We recommend a level at or below 30 kg/t adipic acid, which reflects the abatement level achieved by the large majority of producers world-wide.
- If a standardized ambitious emissions benchmark is introduced, the methodology could be further simplified as measurements and calculations of the rate of N_2O formation would not be necessary.

4.4. Nitric acid

4.4.1. Overview

Nitric acid is mainly used for the production of synthetic fertilizers and explosives. In the industrial production of nitric acid, ammonia (NH_3) is oxidized over precious metal gauzes (primary catalyst) to produce nitrogen monoxide (NO), which then reacts with oxygen and water to form nitric acid. N_2O is an unwanted by-product generated at the primary catalyst. The better a primary catalyst functions, the lower the N_2O emissions. Nitric acid is produced during production campaigns of typically 3-12 months (Kollmuss & Lazarus 2010).

N_2O emissions from nitric acid production can be abated in three ways (Schneider & Cames 2014):

- **Primary abatement** prevents the formation of N_2O at the primary catalyst. According to gauze suppliers, improved gauzes could potentially lead to a 30-40% reduction of N_2O formation (Ecofys et al. 2009).
- **Secondary abatement** removes N_2O through the installation of a secondary N_2O destruction catalyst in the oxidation reactor. The abatement efficiency of the secondary catalyst is often estimated as ranging from 80% to 90%. However, in practice it varies in CDM plants from about 50% to more than 90%. Registered CDM projects achieved an average abatement efficiency of 70% (Kollmuss & Lazarus 2010, Debor et al. 2010).
- **Tertiary abatement** removes N_2O from the tail gas through either thermal or catalytic decomposition. Tertiary abatement can reduce N_2O emissions by more than 90% but involves larger investment and operating costs and more demanding technical requirements than secondary abatement. Registered CDM projects achieved an average abatement efficiency of 86% (Kollmuss & Lazarus 2010, Debor et al. 2010).

Four methodologies have been approved for N_2O abatement from nitric acid production:

- **AM0028** is applicable to tertiary abatement in plants that started commercial operation before 2006. 19 projects used the methodology. In 2013, the methodology was limited to caprolactam production in 2013, and replaced by amending the methodology ACM0019.
- **AM0034** is applicable to secondary abatement in plants that started commercial operation before 2006. 56 projects used the methodology. In 2013, the methodology was withdrawn and replaced by amending the methodology ACM0019.
- **AM0051** is also applicable to secondary abatement in plants that started commercial operation before 2006. The methodology was never used and was withdrawn in 2013. It is therefore not considered in detail in this study.
- **ACM0019** is applicable to both secondary and tertiary abatement and both existing and new plants. 26 projects used the methodology. Since 2013, this is the only valid methodology for nitric acid projects.

Table 4-2 provides an overview of the main features of and differences between the methodologies.

Table 4-2: Overview of methodologies for nitric acid projects

	AM0028	AM0034	AM0051	ACM0019
Projects	19	56	None	26
Technology	Tertiary	Secondary		Secondary and tertiary
Validity	Limited to caprolactam in 2013	Withdrawn in 2013		Valid
Applicability	Plants that started operation before 2006			Existing and new plants
Additionality demonstration	Additionality tool			Automatically additional
Baseline emission factor	Ex-post measurements	Ex-ante measurement campaign	Ex-post measurements	Emission benchmark
Cap on baseline production	Design capacity			No cap
Re-assessment of baseline scenario or additionality	In case of new NO_X regulations			Not applicable

Sources: Authors' own compilation

4.4.2. Potential CER volume

Under the CDM, 97 projects were registered and another four projects were submitted for validation as of January 2014. China is the most important host country with 44 projects. Other important countries are India (5 projects), Uzbekistan (6 projects), South Africa (5 projects), and Brazil, Egypt, Israel and South Korea which host each four projects. Among the 97 registered CDM projects, only 51 have issued CERs as of January 2014. In the current market situation, it is likely that most of the remaining 47 projects have not been implemented. Based on a bottom-up model developed by Schneider & Cames (2014), the 101 published CDM projects could generate approx. 175 million CERs in the period of 2013 to 2020. Potential new projects that have not yet been developed or published are estimated to have a potential of approx. 31 million CERs over the same period.

4.4.3. Additionality

Up to 2011, all three approved methodologies (AM0028, AM0034, AM0051) used the additionality tool to demonstrate additionality. In 2011, ACM0019 was adopted, which deems projects to be automatically additional and employs a dynamic emission benchmark to determine baseline emissions.

N_2O abatement from nitric acid production can be regarded as highly likely to be additional, for similar reasons as for HFC-23 abatement from HCFC-22 production and N_2O abatement from adipic acid production. Non-Annex I countries usually do not have regulations which address N_2O emissions from nitric acid production. Prior to the CDM, secondary or tertiary abatement is not known to have been used in non-Annex I countries and N_2O is usually released to the atmosphere. While plant operators have economic incentives to take primary abatement measures to reduce the rate of N_2O formation, they do not save any costs or generate any revenues – other than carbon market revenues – from the installation of secondary or tertiary abatement. Based on a review from PDDs and literature information, the average technical abatement costs are estimated at €0.9/t CO_2e for secondary abatement and at €3.2/t CO_2e for tertiary abatement (Schneider & Cames 2014). For these reasons, in our assessment, the approach in ACM0019 of assuming this project type automatically additional seems reasonable.

4.4.4. Baseline emissions

Baseline emissions are determined by multiplying the amount of nitric acid production with a baseline emission factor. The methodologies AM0028, AM0034 and AM0051 limit the amount of nitric acid production eligible for claiming emission reductions to the design capacity of the plant in 2005; ACM0019 has no such cap. The baseline emissions factor is determined in three different ways in CDM methodologies: through measurement campaigns conducted prior to the installation of the abatement technology (AM0034), through measurements during the crediting period (AM0028 and AM0051), and by using an emissions benchmark (ACM0019).

All three methodologies using measurements (AM0028, AM0034 and AM0051) aim to provide safeguards to avoid perverse incentives to artificially increase the rate of N_2O formation in order to increase CDM revenues (UNFCCC 2012b; UNFCCC 2013; Schneider & Cames 2014). In AM0028, the baseline emission factor is capped to the level of previous monitoring periods if project participants do not use a primary catalyst that is common practice in the region or has been used in the nitric acid plant during the last three years and if they cannot justify the use of a different catalyst. In addition, key operating conditions of the plants cannot be changed during project implementation. In AM0034, the methodology requires a new baseline measurement campaign to be conducted if the chemical composition of the primary catalyst is changed after project implementation. While these provisions aimed to avoid perverse incentives to increase the N_2O formation due to the CDM, they provide economic disincentives to plant operators to use primary catalysts that reduce the formation of N_2O, as this would lower their CER revenues and could involve additional costs for conducting a new baseline campaign (UNFCCC 2012b; UNFCCC 2013; Schneider & Cames 2014). However, advanced primary catalysts that increase the NO yield and lower the generation of the by-product N_2O are emerging in the industry. They have become widespread in Europe, are gaining market shares in other parts of the world, and have been used in a number of CDM projects prior to their start (UNFCCC 2012b). It is thus possible that some CDM projects applying the AM0034 or AM0028 methodology would, in the absence of the CDM incentives, employ more advanced primary catalysts, in particular over the time frame of three crediting periods, leading to over-crediting (UNFCCC 2012b).

The Methodologies Panel further identified that some plants using the AM0034 methodology had established baseline emission factors which are significantly above the uncertainty range of the IPCC default values and which would result in considerable economic losses for the plant operators (UNFCCC 2012b). The highest reported value from a baseline measurement campaign is 37.0 kg N_2O / t nitric acid, while the highest IPCC default value is 9.0 kg N_2O/t nitric acid, with an uncertainty range of ±40% (IPCC 2006). Such high emission factors indicate that these plants are operated at a high specific ammonia consumption. Plant operators could intentionally reduce the production efficiency during the baseline campaign in order to achieve a higher CDM baseline emission factor (UNFCCC 2012b). Moreover, while inefficient plant operation can be observed in Non-Annex I countries, it seems questionable whether the observed levels of nitrogen loss would continue over the course of three crediting periods. On the other hand, it is important to take into account that the IPCC default emission factors were estimated at times when much less information was available on N_2O formation from nitric acid plants. In particular, continuous measurements over the length of a production campaign, with increasing N_2O emissions towards the end of the campaign, were not available. The values and their assigned uncertainty should therefore not be overweighed.

To address these two issues, the CDM EB withdrew the AM0034 and AM0051 methodologies and limited the applicability of the AM0028 methodology to caprolactam plants in 2013. At the same time, the EB revised the methodology ACM0019, distinguishing the approach between plants that used AM0028 or AM0034 in their first crediting period and other (mostly newer) plants. For AM0028 and AM0034 plants up to their design capacity, the methodology uses the lower value between the historical baseline emissions during the first crediting period under AM0028 and AM0034 and a default value set at the upper end of the uncertainty range of the IPCC default value and declining by 0.2 kg N_2O/t nitric acid per year to reflect technological innovation in primary catalysts that may reduce emissions over time. This approach caps the baseline emissions particularly for those plants that have established baseline emission factors above the IPCC uncertainty range. It also reduces the maximum amount of baseline emissions that can be claimed over time to account for technological innovations in primary catalysts. For production above the design capacity and other (mostly newer) plants, the methodology uses a more ambitious emissions benchmark set at 3.7 kg N_2O/t nitric acid in 2013 and declining by 0.2 kg N_2O/t nitric acid per year, up to a level of 2.5 kg N_2O/t nitric acid in 2020 which is maintained in subsequent years.

The new approach has several advantages but also some shortcomings:

- Importantly, using default emission benchmarks – whatever the real baseline emissions from a specific plant are – fully avoids perverse incentives for plant operators not to use advanced primary catalysts that reduce the formation of N_2O. Plant operators have incentives to innovate, as this lowers their project emissions and increases the number of CERs issued;

- Using default emission benchmarks further fully avoids the risk that plant operators could intentionally increase the rate of N_2O formation during a baseline campaign in order to maximize CER revenues;

- Using default emission benchmarks can lead to over-crediting in plants that actually have lower N_2O formation rates and to under-crediting in plants that actually have higher N_2O formation rates. Both under- and over-crediting is likely to occur since the N_2O formation rate observed in CDM projects varies by a factor of 10 from 3.5 to 37.0 kg N_2O/t nitric acid, with an average value of 8.6 kg N_2O/t nitric acid (UNFCCC 2012b). Significant over- and under-crediting can have several unintended consequences (Schneider et al. 2014). Plants with a high N_2O formation rate may not be able to reduce their project emissions significantly below the emissions benchmark and may thus not be implemented – although their implementation would be possible with a project-specific baseline. Such 'lost opportunities' could increase the global cost of GHG abatement.

The overall impact on environmental integrity depends on the methodology and plant type (Table 4-3). For newer plants, the emission benchmark declining from 3.7 to 2.5 kg N_2O / t nitric acid is rather conservative and will likely lead to under-crediting for most – if not all – plants. For plants that used AM0028 or AM0034 in the first crediting period, the declining project-specific benchmark in ACM0019 is a reasonable baseline on average over all projects in our assessment; projects with higher baseline emission rates than the IPCC range will receive less CERs, while some over-crediting could occur for projects that adopt more advanced catalysts at a faster rate than the decrease of 0.2 kg N_2O / t nitric acid per year foreseen in the methodology. The use of AM0028 and AM0034 could lead to over-crediting in some instances, due to the issues identified above. Considering all plant types and methodology versions together, it seems likely that the approaches for 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.

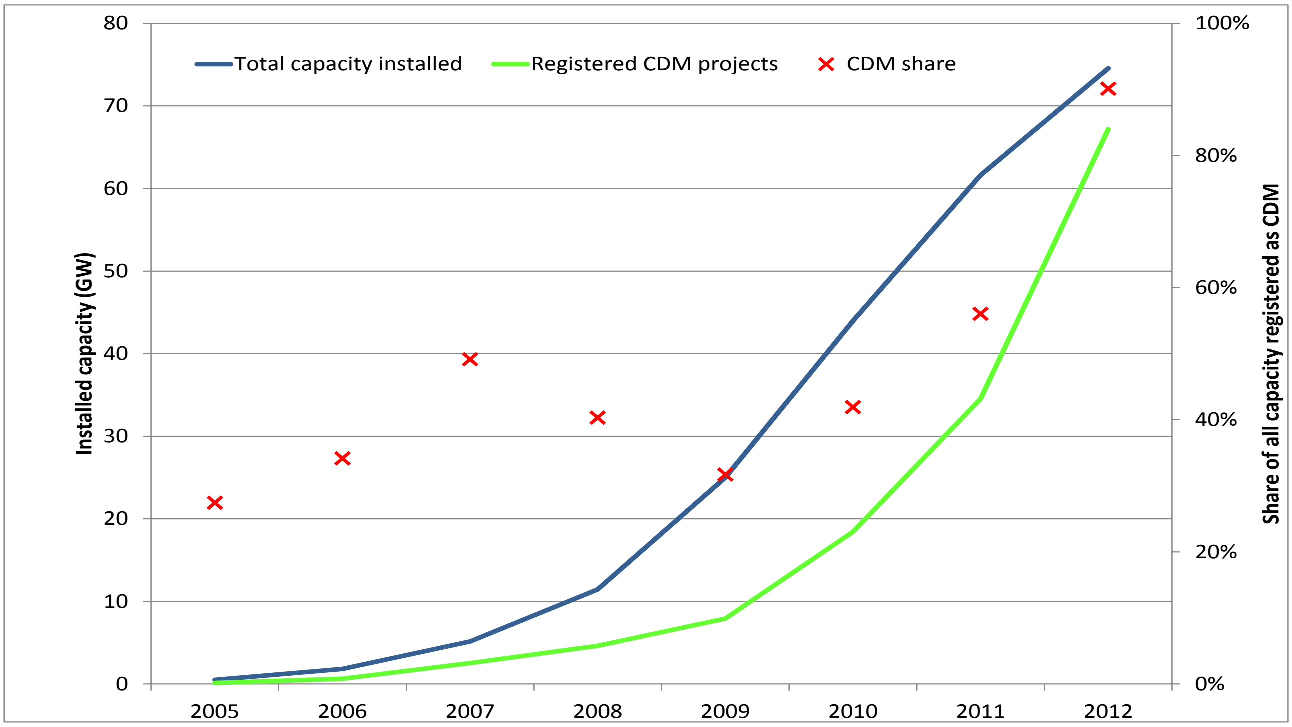
49 ACM0002, AMS-I.A, AMS-I.D, AMS-I.F.

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.

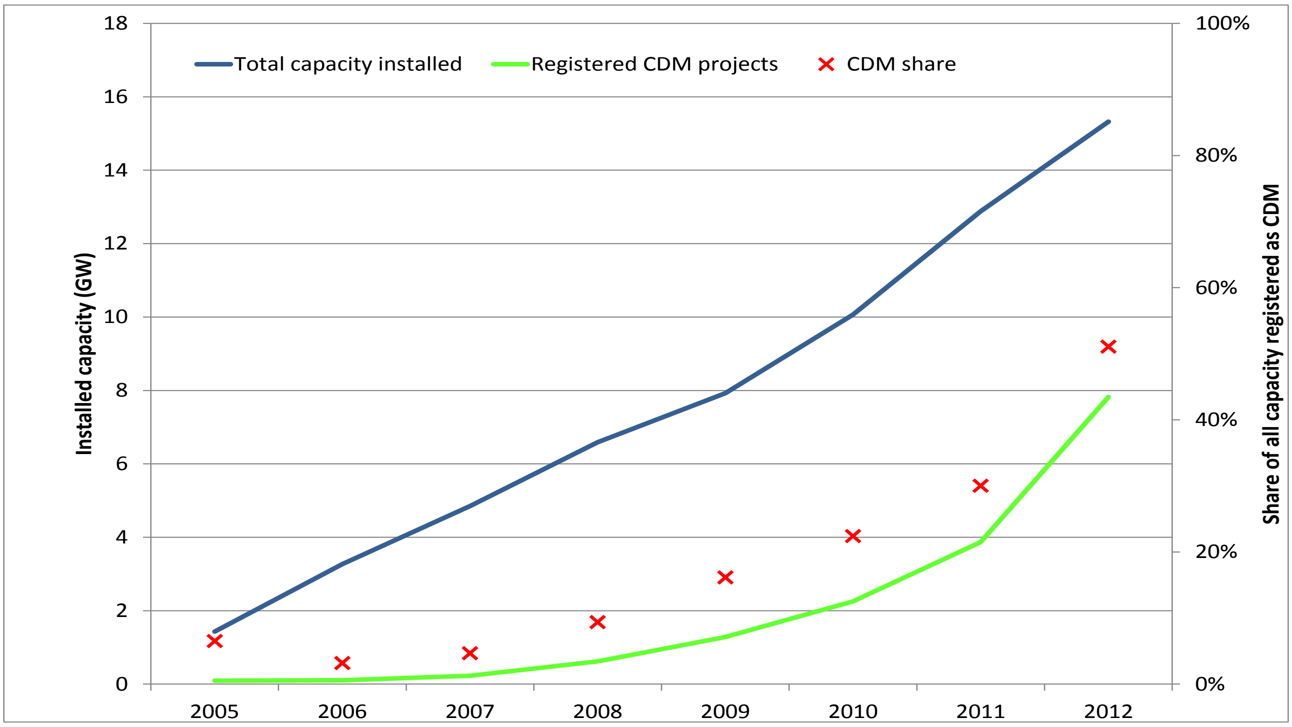
52 The total installed capacity between 2005 and 2012 is taken from the World Wind Energy Association statistics (WWEA 2015) and accumulated across the years. The installed capacity of projects using the CDM is taken from UNEP DTU (2014) and accumulated, too. The installation year is taken as the starting 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



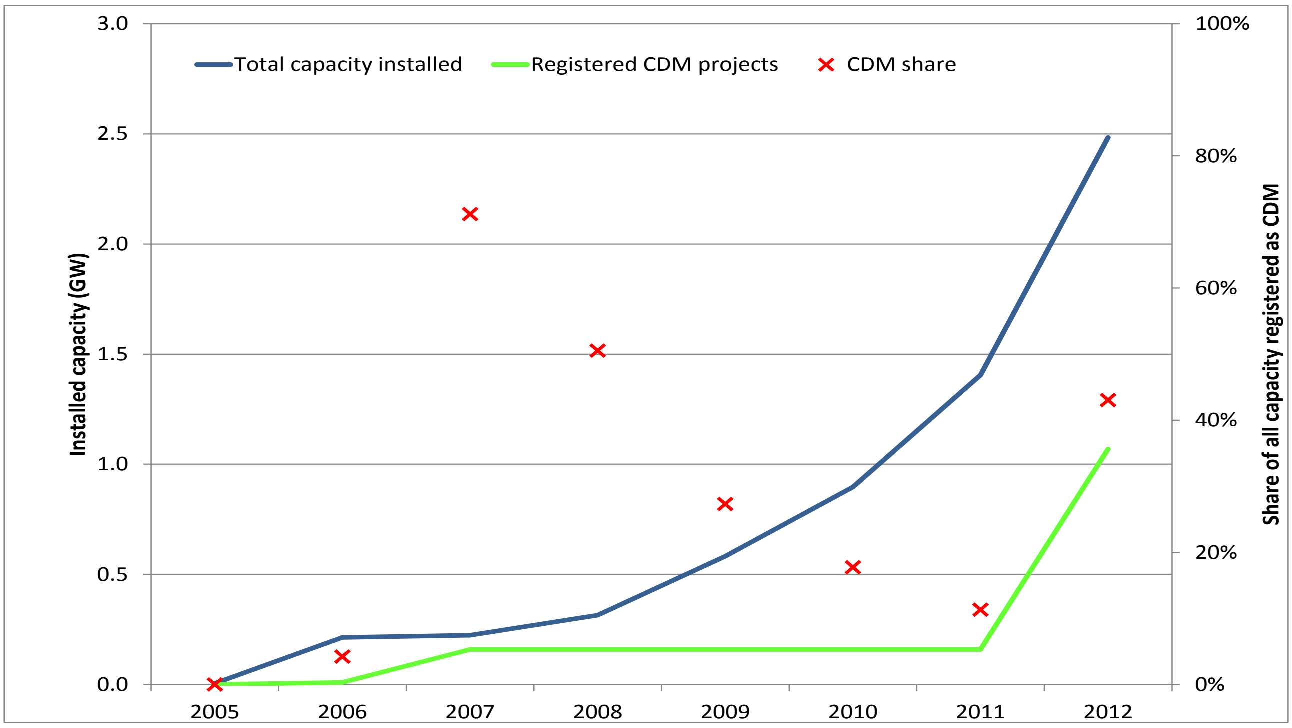
Sources: UNEP DTU 2014, WWEA 2015, authors' own calculations

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.

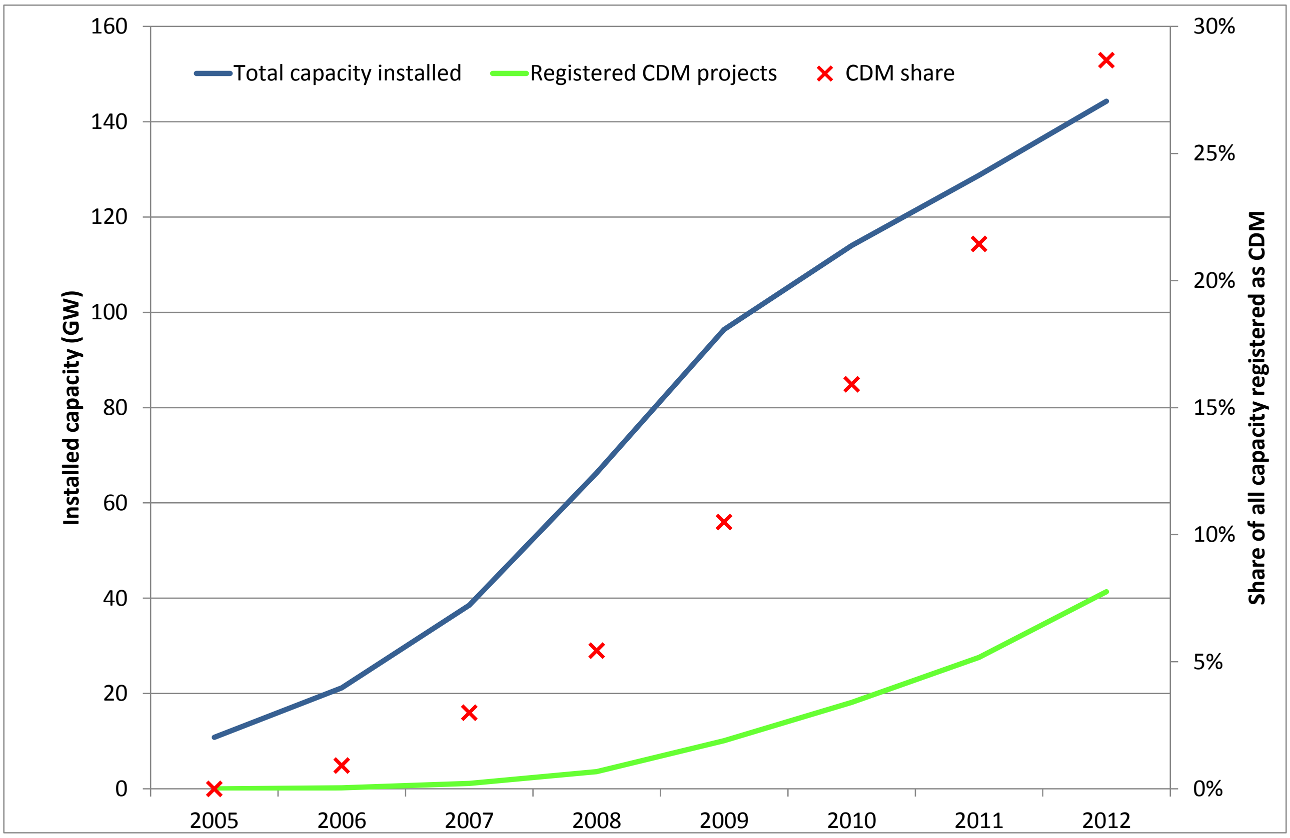
- The provisions for low-cost/must-run plants should be reviewed, including a clear definition of such plants and provisions which ensure that such plants are included in the operating margin if they are at the margin of the dispatch at any time;
- The grid emission factor tool should be revised to reflect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

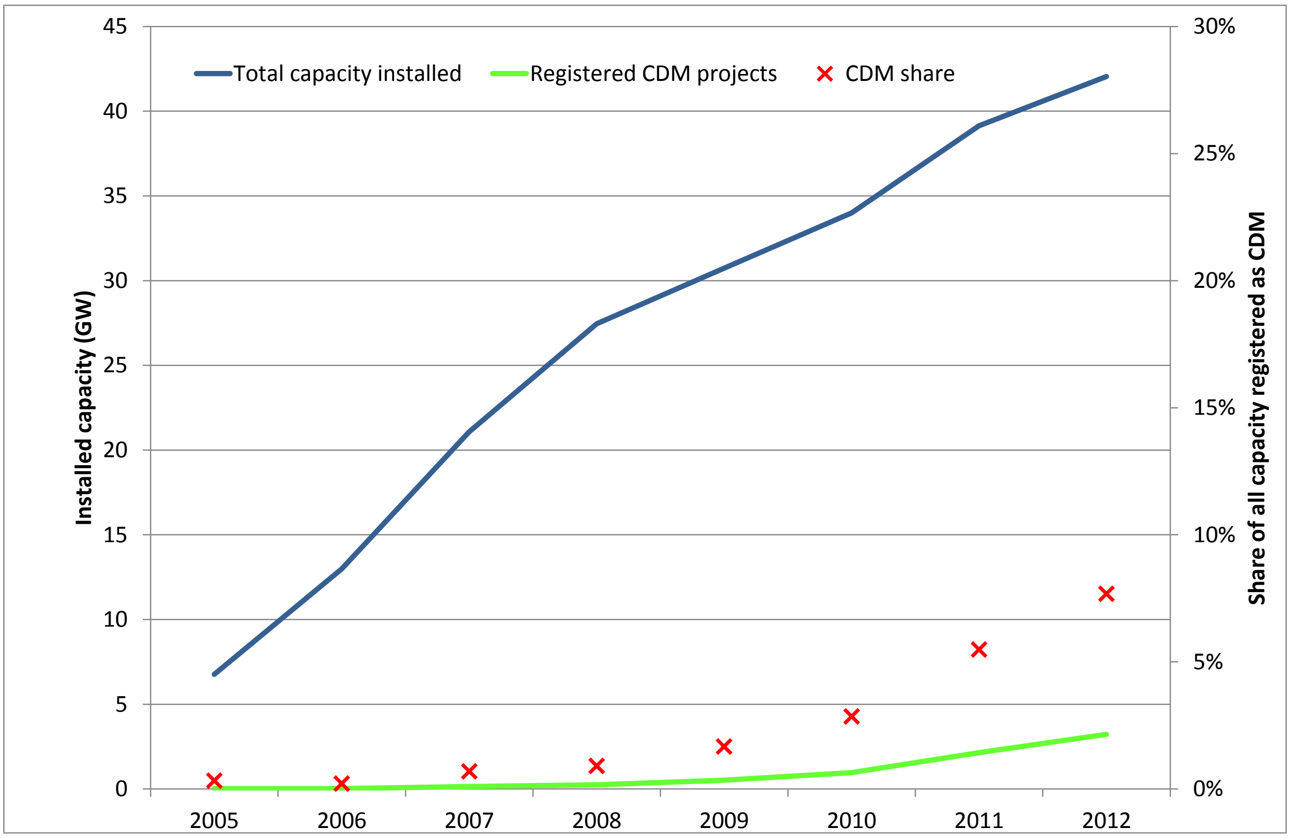
As for wind power, Figure 4-5, Figure 4-6 and Figure 4-7[64] illustrate the development of hydropower capacity and the use of the CDM in China, India and Brazil. In all three countries, hydropower has played an important role for many decades. Significant capacity has been installed without the CDM.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

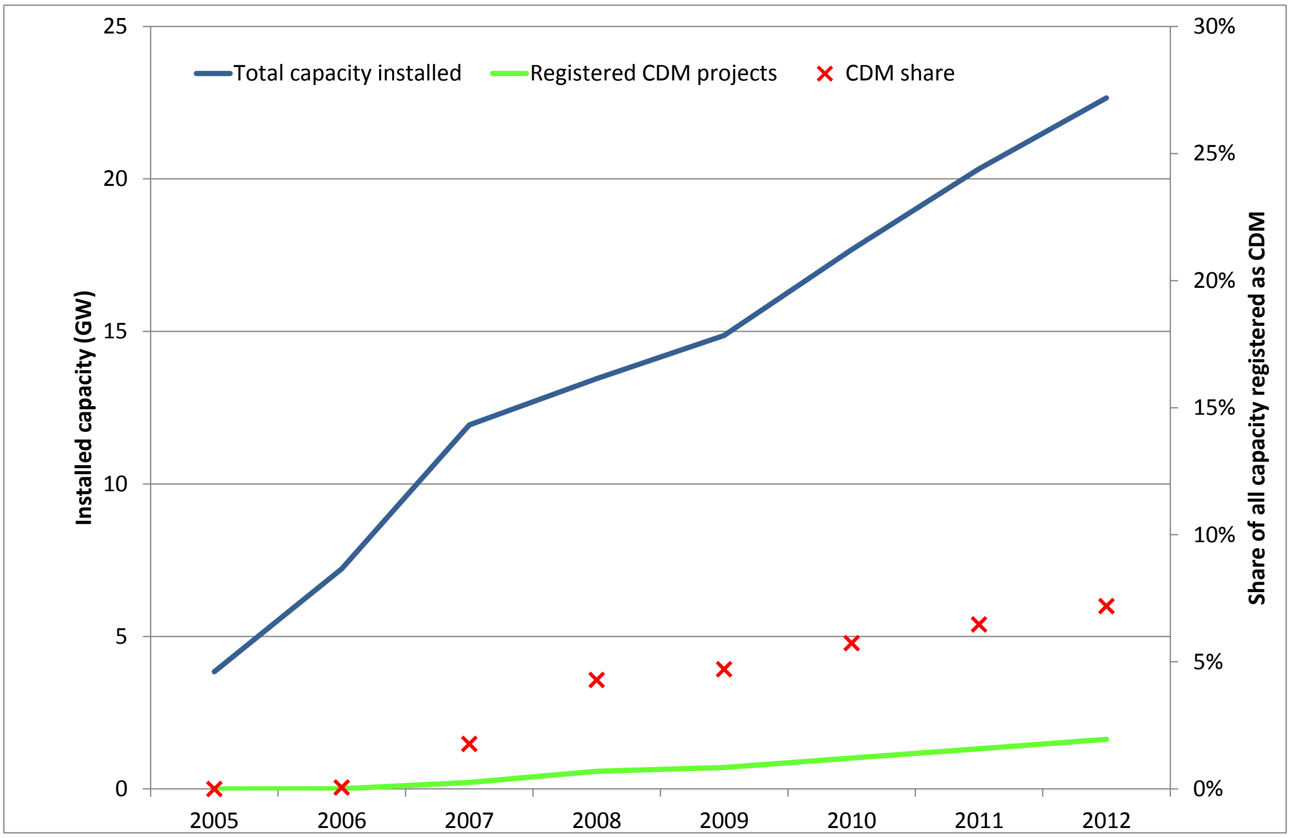
In the case of Brazil (Figure 4-7), the cumulated installed capacity in 1990 amounted to approx. 53 GW. Almost 4 GW of capacity was added in 2005, with no CDM projects being registered in that year. Even after the introduction of the CDM, only a small share of hydropower projects used the CDM (approx.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

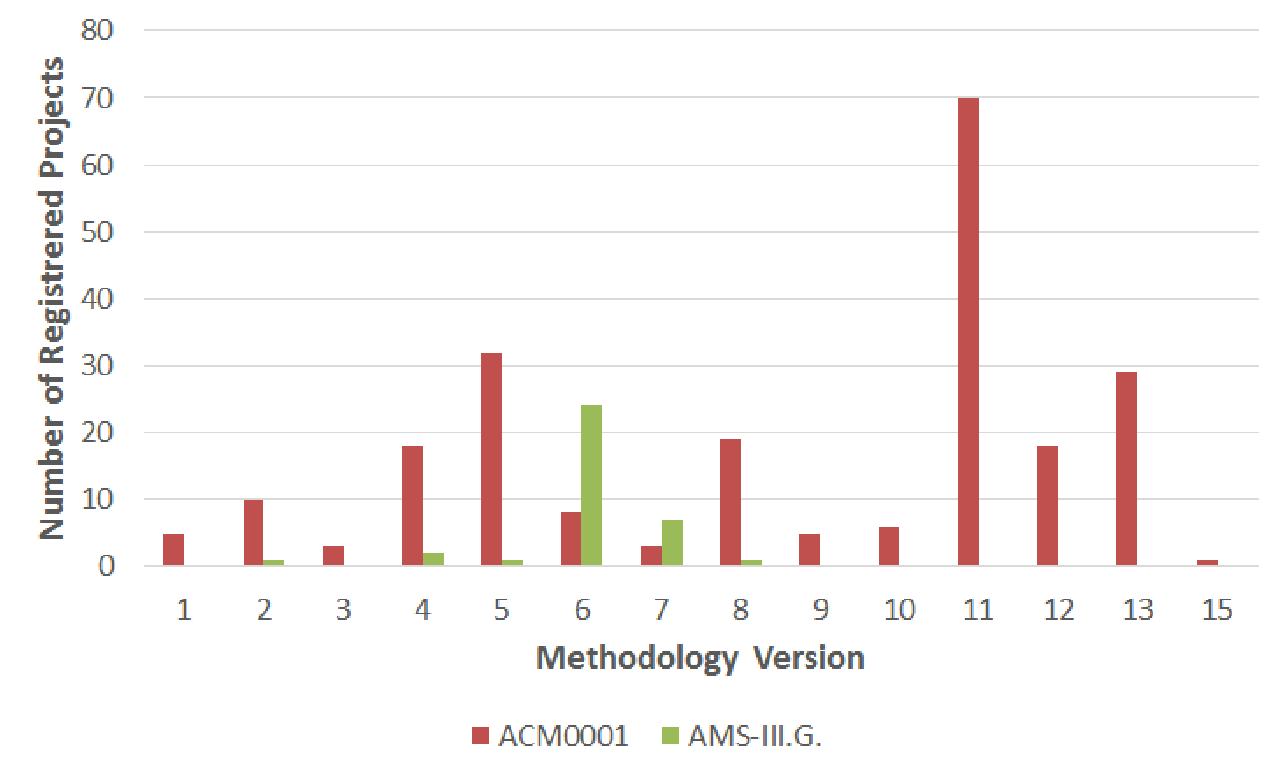
Version 15, as shown in Figure 4-8. The CDM EB will review the validity of these standardized procedures after a three-year time period.

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

Additio-nality	• 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 addition-ality 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 op-tion 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-sMZsZlso1q

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 between 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%.

[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.

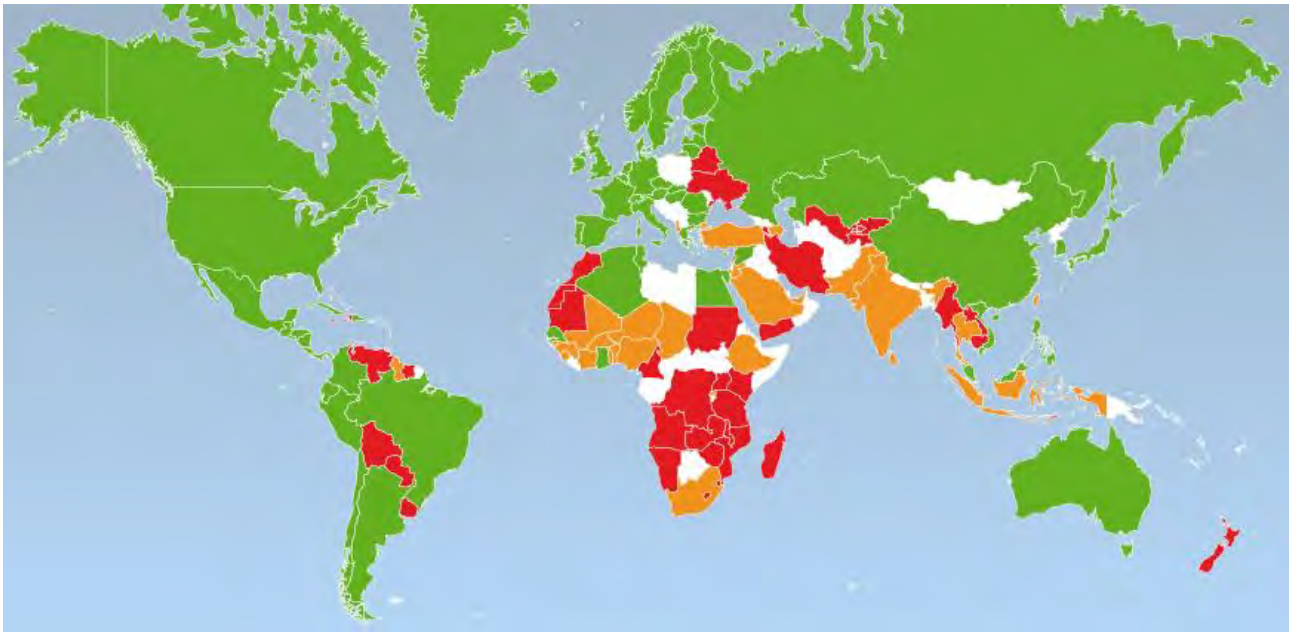
[87] http://www.sdpc.gov.cn/zjgx/t20080508_210093.htm.

[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.

[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

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

Project type	**Additionality** [1)]	**Over-crediting** [2)]	**Other issues**	**Overall environmental integrity** [3)]
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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Comments Submitted on the Climate Action Reserve Forest Project Protocol Revision
December 13, 2018

To whom it may concern:

I submit these comments in response to the recently posted Climate Action Reserve Forest Project Protocol Revision (v5.0). My comments are narrow and concern one aspect of the revision, specifically the portion of the protocol addressing the Quantification of Secondary Effects for Improved Forest Management Projects (Section 6.1.6., p54-5).

The current version of the revised protocol cites a literature review I conducted (Galik 2018) as the source for a default secondary effect value of 40%. I am concerned that use of that estimate without further elaboration on where the number came from, how it was derived, and how it was intended to be used is potentially confusing and misleading.

The cited report was written to inform the development of a suite of land management and land use practices for greenhouse reduction in Merced County. As part of that project, I conducted a literature review to assess a range of leakage estimates for a variety of land use activities, and, based on that review, provided recommendations for discounts that could be applied to identified practices at either the activity or county scale. The review itself identified a wide range of estimates in the literature, some negative, some positive, some low in magnitude, others quite high. Because of this, it appears as though the 40% leakage estimate being attributed to Galik (2018) by the revised protocol comes from a simplified flowchart that was developed to assess activity-specific leakage risk.

In describing the flowchart, I took particular care to note the challenges associated with relying on a single estimate derived from the literature:

> "It is important to again remind the reader that leakage is an intervention-specific phenomenon. There are inherent tensions between development of a simplified tool for evaluating the magnitude of leakage risk for whole classes of activities and derivation of specific estimates of leakage risk based upon the unique market and carbon parameters of the specific activity in question...The figure below also does not capture the carbon density of affected land uses, nor does it fully consider the price elasticities of supply or demand. The value of the figure below should thus be seen in its conceptualization of the process for considering

whether leakage is of concern, and less in the particular values assigned at the end." (Galik, 2018; p12)

This context is missing from the protocol revision, and masks both how the number was derived—in Galik (2018), it was "approximated from estimates reported in Murray et al. (2004) [and] Wear and Murray (2004)" (p12)—as well as how the estimate and the flowchart in which it is embedded was expected to be used.

I understand that there is a desire to develop approaches that provide certainty for project developers and that are easy to use, replicable, and consistent, all the while ensuring that any registered credits represent actual, real, quantifiable net GHG reductions. For the sake of transparency, however, I request that CAR substitute the simple citation of my literature review with their own justification for why a particular value was chosen and how it was derived. That will allow for a more open and transparent discussion about the appropriateness of any discount and/or the assumptions that went into its estimation.

Sincerely,
Christopher S. Galik, Ph.D.

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Galik, C.S. 2018. An overview of leakage risk and mitigation approaches for land management activities in Merced County, California.

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This version that CAR emailed me is identical to the version found on line here: https://maps.conservation.ca.gov/TerraCount/downloads/Appendix_J_Leakage.pdf

An Overview of Leakage Risk and Mitigation Approaches for Land Management Activities in Merced County, California

Christopher Galik, Ph.D.
Final Draft
February 22, 2018

This analysis provides an analysis of leakage risk for a variety of greenhouse gas (GHG) mitigation activities to be implemented by or in cooperation with Merced County, California. First provided is a literature review on the concept of leakage to ground the analysis that follows. From this, a simplified heuristic is developed to assess leakage risk from project activities envisioned for Merced County. The analysis concludes with a short review of potential mechanisms to account for, minimize, and/or otherwise address leakage.

An Overview of Theory and Empirical Evidence

In an overview of land-based carbon sinks, management, and accounting, IPCC (2000) defines leakage as "changes in emissions and removals of greenhouse gases outside the accounting system that result from activities that cause changes within the boundary of the accounting system" (p11). A similar but more detailed definition is put forth by Henders and Ostwald (2012) in their review of leakage accounting mechanisms from both the published literature and existing project accounting standards: "Carbon leakage refers to the displacement of greenhouse gas (GHG) emissions from one place to another due to emission reduction activities. It is caused by a direct or indirect shift of activities that create those emissions from within an emissions accounting system to out of that system" (p34). Though the two definitions are very similar, the latter definition is adopted in this analysis owing to its explicit consideration of direct and indirect effects.[1]

Several authors have endeavored to further differentiate types of leakage within the broader category. For example, IPCC (2000) references four specific types of leakage: activity displacement, demand displacement, supply displacement, and investment crowding. Murray (2004) breaks leakage down into two separate phenomena: "Investment crowding" (uptake of activity in one area displaces what would have

[1] Note that this definition does not include changes in upstream or process emissions that arise as part of the activity itself (i.e., a reduction in fertilizer manufacturing emissions associated with a reduction of fertilizer use). This is not considered leakage, *per se*, as it can reasonably be assumed to fall within the accounting system for that particular activity.

otherwise happened elsewhere [e.g., tree planting]) and “slippage” (reduction in production in one area inducing increased production elsewhere). In their exploration of conceptual frameworks for the analysis of leakage in project-based activities, Aukland et al. (2003) discuss leakage as either primary and secondary, or direct actor-induced, activity shifting drivers versus indirect, market-induced drivers. A similar distinction is adopted by Vöhringer et al. (2004), though they lump both into the singular category of “economic leakage”, with primary (including activity shifting) being attributable to a change in production factors (i.e., displaced individuals) and the second (including market-induced) being attributable to changes in commodity prices associated with project activity. Schwarze et al. (2002) and Jonsson et al. (2012) similarly adopt a primary-secondary differentiation, a distinction further used herein.[2]

The Factors Affecting Leakage Risk and Magnitude

As a general rule, there is a risk of leakage when an activity reduces access to a particular resource without providing access to alternatives (IPCC, 2000). As Chomitz (2002) notes, “most projects have to be considered as part of integrated systems” (p38). The reduction of a particular resource, product, or commodity in one place can thus be expected to lead to an increased production of the same or substitutable resource, product, or commodity elsewhere (e.g., Wear and Murray, 2004).

Multiple authors have reviewed the factors associated with leakage risk and magnitude. Assuming that a given activity reduces the supply or a particular resource, product, or commodity, leakage will be highest when there is a relatively fixed need for that resource, product, or commodity and a relatively large area over which it could be supplied (Chomitz, 2002). Alternatively, leakage will tend to be lower when substitutes are hard to come by or users are highly sensitive to price (Chomitz, 2002; Gan and McCarl, 2007; Murray et al., 2004). Also relevant is the carbon density of targeted and non-targeted areas and the size of the market affected relative to the total (Murray, 2008).

These factors can be distilled into a more formal representation of leakage risk. In their analysis of leakage associated with U.S. forest set-asides, for example, Murray et al. (2004) develop a functional form yielding the following insights (p114):

- Leakage is enhanced the more responsive suppliers are to price;
- Leakage is enhanced the less responsive demanders are to price;

[2] This primary-secondary distinction is confused somewhat by previous work that refers to leakage itself as a secondary effect (and that project activities provide the primary, intended effect). See, e.g., Gershenson et al. (2011).

- Leakage is enhanced the higher the ratio between carbon density on non-targeted areas relative to targeted areas;
- Leakage is enhanced as the size of the restriction falls relative to the total market.

The first three points are well-represented elsewhere in the literature, but the final point is perhaps less intuitive and more contentious. As a market-driven phenomenon, leakage is moderated by changes in supply and price of given resource, product, or commodity. All else equal, affecting a small share of a particular resource relative to the total is likely to have little effect on supply (and thus price), so total quantity demanded should be similar, leading to increased production elsewhere. Thus it cannot be assumed that activities affecting a small area are without leakage risk; the opposite is in fact the case.

Evaluation of Leakage Associated with Land-Based GHG Activities

The literature contains multiple analyses of leakage from land-based GHG activity implementation using either partial equilibrium (PE) or computable general equilibrium (CGE) models.[3] One seminal study, Murray et al. (2004), uses the Forest and Agricultural Sector Optimization Model (FASOM) to estimate leakage rates of forest set-aside, avoided agricultural conversion, afforestation, and joint afforestation-avoided conversion programs in the U.S. They find that leakage magnitude differs both by activity and across regions. For instance, forest set-aside programs in the Pacific Northwest were associated with less leakage (16.2%) than programs in the South Central region (68.3%) owing to the higher carbon density in the former. Allowing harvest from acres enrolled in avoided conversion programs reduced leakage but also necessarily reduced carbon storage on harvested areas.

Alig et al. (1997) also use FASOM to assess the implications of “forced” afforestation of U.S. pastureland. Similar to Murray et al. (2004), Alig et al. provides general confirmation of leakage in land-based activity implementation, showing substantial increased conversion in other land use types relative to base case, particularly in the south where the afforestation program was implemented. Elsewhere, Sohngen and Brown (2004) develop a country-specific model to assess leakage associated with secondary or market-induced leakage from retired timber concessions in Bolivia. They estimate leakage rates of 5-42% depending on different assumptions of biomass decomposition rates, capital constraints, demand elasticity, and magnitude of global sequestration efforts. Leakage is also higher in longer projects and when there is

[3] Partial equilibrium models assess changes in a limited number of sectors of the economy. CGE models assess changes economy-wide.

greater local reliance on products that would have otherwise been produced on retired lands.

Nepal et al. (2013a) meanwhile use the U.S. Forest Products Module and Global Forest Products Model to evaluate the potential implications of a forest carbon reserve program at different carbon prices. They find substantial leakage (71-88%) across scenarios, with rates increasing with as carbon prices increase and, due to budget-constrained nature of their hypothetical program, as enrolled acres fall. Total observed leakage rates, along with trend of higher rates of leakage associated with smaller affected market share, is consistent with Murray et al. (2004). A similar analysis is presented in Nepal et al. (2013b), though features only the two higher carbon price scenarios and places a greater emphasis on timber market impacts of the forest carbon reserves.

At the international level, Gan and McCarl (2007) assess the transnational leakage associated with national forest conservation initiatives. Using the Global Trade Analysis Project (GTAP) model, they estimate that over three-quarters of reduced forestry production in the U.S. would be shifted to other countries in the absence of global implementation of the program. Coordination between a few select countries leads to only minimal reductions in the proportion of displaced production. Lee et al. (2004) use the U.S. Agricultural Sector Model (ASMGHG) to conduct a high-level analysis of agricultural emissions under different international climate change regimes, ranging from U.S. unilateral action to global participation, finding substantial leakage in the case of unilateral action. The authors demonstrate this for U.S. action, but imply that leakage to the U.S. could also occur should the U.S. be the lone non-participant. In the case of global participation, U.S. prices rise and net mitigation is lower as costs are internalized.

While such analyses are useful for assessing aggregate effects and general trends, other modeling approaches have generated insight into finer scale interactions between individual actors. Delacote et al. (2015), for instance, use an agent-based model to assess the leakage implications of a variety of policy mechanisms to avoid forest conversion. Their findings are suggestive of several general trends. First, the distribution and intensity of forest loss matters. Second, the distribution of actors across a landscape matters. Third, the type of policy interacts with the spatial distribution of actors to generate either higher or lower rates of leakage.

Also represented in the literature are empirical analyses of leakage resulting from GHG mitigation and related conservation activities. These studies use a variety of data and statistical techniques to assess changes associated with implementation of a particular program or project. Wear and Murray (2004) for example provide an empirical evaluation of inter-regional shifts in timber sales following restrictions on western forest harvests put in place starting in the late 1980s. They find that consumption of timber in the U.S. is relatively unchanged in spite of western timber restrictions, suggesting substitution of supply. Although their analysis was not specifically designed to simulate the effects of carbon policy, estimated leakage rates ranged from 43% when assessing changes at the regional level, 58% when considering national changes in supply, and 84% when considering supply response at the international level.

Leakage from the Conservation Reserve Program (CRP) has likewise been debated in the literature. Over the course of several articles in the early 2000s, two author teams debated the empirical evidence for leakage in the CRP (termed “slippage” in the analyses themselves). Wu (2000) used National Resources Inventory (NRI) data to assess so-called slippage associated with CRP, finding that the program potentially contributed to increases in non-cropland conversion on the order of 30% in the Corn Belt region, 16% in Lake States, and 15% in the northern plains. Importantly, Wu also estimated net resource changes to be smaller than acreage changes, as gains in erosion benefits from set-aside areas were generally larger than losses on converted lands.

In challenging the calculated leakage rates estimated by Wu (2000), Roberts and Bucholtz (2005) cite the fact that areas that are likely to have more acres enter the CRP are also likely to have more marginal acres be removed from production for some other reason. They find no consistent evidence for leakage in the CRP, noting that the data used cannot be used to estimate secondary (“price feedback effect”) leakage and that primary (“substitution effect”) leakage is difficult to estimate given the array of factors that influence individual farmer decision-making. In a response, Wu (2005) refutes many of the claims offered by Roberts and Bucholtz (2005), restating that both the original (Wu, 2000) and commenting piece (Roberts and Bucholtz, 2005) show evidence of significant slippage under the CRP. A subsequent and final rejoinder (Roberts and Bucholtz, 2006) refers to the potential for substitution effects as “partially valid” (p513) but suggests that they are likely to be small given high turnover observed in agricultural land markets.

Boer et al. (2007) use a logit model to assess likelihood of land use conversion and potential leakage associated with forest restoration projects in Indonesia. In their analysis, the authors used satellite imagery and other available data to generate estimates of land use change associated with individual project activities. Though useful and informative, the authors also reflect on the data-intensive and time-constrained nature of their approach. They specifically caution that approaches such as theirs should not be used to estimate trends far into the future, as it is necessary to make assumptions on what is driving observed changes.

Finally, Alix-Garcia et al. (2012) use matched plots to assess the effectiveness of a forest conservation payment program in Mexico, finding evidence of both substitution or activity-shifting (primary) and price-induced (secondary) leakage, or “slippage” as they term it. They find evidence of activity-shifting leakage at both very low and very high poverty rates, but observe that the direction of effect varies, with negative leakage occurring in areas of high poverty and positive, spillover-type effects occurring in low poverty areas. They likewise discuss the seriousness of the leakage threat, but also the difficulty in actually observing it unless markets are small and price changes are localized.

Risk and Accounting Mechanisms for Activities in Merced County, California

The literature has demonstrated the theoretical basis and empirical evidence for leakage in forest and agricultural GHG mitigation activities. The next step in this analysis is to further consider the specific leakage risks posed by activities considered for implementation in Merced County and the best mechanisms for accounting for that risk. A subsequent section will then review the potential approaches for mitigating leakage risk to the maximum extent possible.

As reviewed above, leakage is a potential problem when a given activity reduces the supply of a particular resource, product, or commodity. This general phenomenon can be viewed through the lens of activities under consideration in Merced County. Activities that affect agricultural yields, for example, can be expected to generate some degree of leakage (Müller-Lindenlauf, 2009). Conservation activities, including avoided deforestation, are likewise subject to both activity-shifting (primary) and market-induced (secondary) leakage (Aukland et al., 2003). Alternatively, improved practice projects, such as agricultural intensification or reduced impact logging, can potentially avoid both types of leakage so long as existing land uses are not affected and a constant supply of outputs is maintained (Aukland et al., 2003; Müller-Lindenlauf, 2009). Assumptions of minimal leakage also apply to situations where there is not a current market for a given output, such as in the case of urban forestry activities (Poudyal et al., 2011).

There are on the order of ten separate activities and ten separate land uses considered by TNC and the County; even if not all activities are relevant to every land use, the number of possible permutations is quite large. To create a tractable approach for evaluating leakage across these multiple and varied combinations, this analysis begins with a screening exercise based on the degree to which an activity affects the supply of a particular resource, product, or commodity. A rough simplification of possible start (baseline) and end (project activity) conditions for activities considered in this project yields six separate configurations:

1. Baseline: Land is managed for some commercial amenity, output, or commodity; Project Activity: Land will no longer be managed for or displaces some marketable commercial amenity, output, or commodity.
2. Baseline: Land is managed for some commercial amenity, output, or commodity; Project Activity: Land will be managed for or displaces some other marketable commercial amenity, output, or commodity.
3. Baseline: Land is not managed for some commercial amenity, output, or commodity; Project Activity: Land use changes, but is still not managed for or displaces a marketable commercial amenity, output, or commodity.
4. Baseline: Land is not managed for some commercial amenity, output, or commodity; Project Activity: Land use changes, and will now be managed for or displaces some other marketable commercial amenity, output, or commodity.
5. Baseline: Land is not managed for some commercial amenity, output, or commodity; Project Activity: Change in management strategy only, with no change in land use or output.
6. Baseline: Land is managed for some commercial amenity, output, or commodity; Project Activity: Change in management strategy only, with no change in land use or output.

The general activities under consideration for Merced County can then be arrayed across these conditions (Table 1). Generally speaking, activities falling into the first and second categories face the greatest potential for leakage. The extent to which the risk of leakage rises above some minimal or *de minimis* level is dependent upon the particulars of the activity, such as the land use currently in place, the new land use, the carbon content of both uses, and affected markets. The balance of the analysis will then focus on how to assess the effect of these particulars on activity leakage risk.

From Table 1, a subset of activities can be excluded from further analysis owing to their minimal leakage risks. Improved Nitrogen Fertilizer Management and Replacing Synthetic Nitrogen Fertilizer with Soil Amendments activities, for example, are unlikely to generate significant leakage so long as yields are maintained. There is the theoretical potential for some expansion of synthetic fertilizer use to occur if reduction of use in Merced County led to a decline in price of the product, but that risk is assumed to be very small. The leakage risk associated with Mulching is also assumed to be very small, again so long as yields are maintained. Finally, Urban Forestry can be assumed to generate little or no leakage due to the general absence of a market for associated products. For the balance of activities included in Table 1, some manner of leakage accounting is prudent, even if only to show that a particular activity in a particular instance poses little risk. To do so first requires a review of the unique circumstances surrounding each activity.[4]

Table 1. Start and end conditions for activities considered for implementation in Merced County.

	Currently in marketable use, displaces/shifts away from marketable use	Currently in marketable use, displaces/shifts to some other marketable use	Currently not in marketable use, displaces/shifts to some other non-marketable use	Currently not in marketable use, displaces/shifts to some other marketable use	Currently not in marketable use, no change in output	Currently in marketable use, no change in output
Avoided Conversion		X		X		
Improved Nitrogen Fertilizer Management						X
Replacing synthetic fertilizer with soil amendments						X
Restoration of Oak Woodlands	X	X	X	X	X	X
Cover Crops	X	X				X
Mulching						X
Riparian Restoration	X	X	X		X	X
Urban Forestry				X	X	
Improved Forest Management	X	X		X		X
Fallowing	X	X				
Hedgerow Planting	X		X		X	X

<u>Avoided Conversion</u>: The activity area is permanently protected through zoning changes (e.g., to open space) or conservation easements that dedicate the project area to a natural condition. The project area may be used for a variety of purposes that maintain the natural land cover.

- Primary: some degree of conversion could still occur, just elsewhere in the immediate vicinity.
- Secondary: some degree of new conversion occurs elsewhere in response to decrease in supply of given commodity. The magnitude of risk will depend on the specialization and localization of market affected, with highly localized or specialized markets tending to have smaller risks of secondary leakage.

[4] Note that definitions for each activity are derived from information listed in the document "Activity Definitions_171222.pdf" (J. Remucal, Pers. Comm., 22 December 2017).

Cover Crops: Activity reductions are based on adding either seasonal leguminous or non-leguminous cover crops that supply partial fertilizer demand to irrigated commodity crops, thus reducing fertilizer application. Other cropland management practices remain the same with adoption of the conservation practice.

- Primary: it is possible that an individual actor may wish to change cropping practices to make up for foregone supply associated with cover cropping.
- Secondary: some degree of new conversion could occur elsewhere in response to a decrease in supply of given commodity. To the extent that cover crops are themselves introducing a new commodity, there may be positive leakage effects that may counter any displaced production from primary crop.

Hedgerow Planting: Reductions result from replacing conventionally managed and fertilized annual cropland with one row of unfertilized, woody plants.

- Primary: it is possible that an individual actor may wish to change cropping practices to make up for foregone supply associated with land set aside for conversion to hedgerow.
- Secondary: some degree of new conversion could occur elsewhere in response to decrease in supply of given commodity.

Oak Woodland Restoration: Reductions are the results of the restoration of grasslands to native oak woodland cover in ecologically appropriate areas.

- Primary: it is possible that an individual actor may wish to change management practices to make up for foregone services associated with area restored.
- Secondary: some degree of new conversion could occur elsewhere in response to decrease in supply of given commodity.

Riparian Restoration: Reductions are the result of woody plantings on degraded streambanks, which are characterized by lack of vegetation, allowing the movement of heavy runoff through the riparian zone directly into stream channels.

- Primary: it is possible that an individual actor may wish to change cropping practices to make up for foregone supply associated with cover cropping.
- Secondary: some degree of new conversion could occur elsewhere in response to decrease in supply of given commodity.

Improved Forest Management: Reductions are the result of increased productivity of managed forest systems. This can be yielded through either extended rotations for even-aged systems so as to sequester more carbon on the stump or in eventual wood products, and/or through increased productivity of the stand as a whole through appropriate silvicultural practices.

- Primary: it is possible that an individual actor may shift harvest activity to other holdings if activities (e.g., rotation extension) result in a decline in forest product yield.
- Secondary: additional harvests could occur if the activity results in a reduction in the supply or a change in the type of forest products either over the short or long term.

Having documented the factors influencing leakage in each activity type, the next step is to account for the magnitude of leakage risk associated with each activity type. Primary leakage occurs either in the immediate vicinity of the displaced activity or on lands held or managed by affected actors. As such, it is perhaps better addressed through pre-activity planning and post-activity monitoring. Secondary leakage is more difficult to observe, though as described above, the literature suggests that the magnitude of leakage is associated with the price responsiveness of both suppliers and demanders, the ratio of carbon density between target and non-targeted affected areas, and the size of activity relative to the full market for that activity (e.g., Murray et al., 2004).

The literature also details multiple approaches by which leakage risk can be estimated for a variety of projects, programs, and activities. Henders and Ostwald (2012), for example, review leakage accounting approaches for multiple types of land-based GHG mitigation activities, including the use of generic discount factors to account for secondary leakage, many of which adjust the magnitude by site conditions (carbon content, carbon intensity of activities, etc.). They also review the use of qualitative assessments such as interviews or surveys to gauge the extent to which individuals engage in practices generating or leading to leakage.

Elsewhere in the literature, the leakage associated with particular activities or programs are estimated through the use of economic models or empirical data specific to the activity in question (see "Evaluation of Leakage Associated with Land-Based GHG Activities," above). In the absence of economic models to estimate leakage, rough approximations can also be generated using estimates of supply and demand function response (Murray, 2008). VCS (2017), for example, recommends basing secondary leakage on estimates of supply/demand elasticities and peer-reviewed approach for estimating leakage rates.

Henders and Ostwald (2012) suggest using historical averages to establish baseline of logging activity, then monitoring of activity under project to see whether volume changes with deductions made to reported carbon benefits if necessary (see also Schwarze et al., 2002). Wu (2000) argues that price-induced slippage (similar in concept to secondary leakage) stemming from conservation program implementation requires time-series data on prices, program enrollment trends, and land use change to estimate net effect. Vöhringer et al. (2004) meanwhile suggest first specifying the drivers of leakage by identifying market leakage effects (i.e., causes). From there, leakage factors should be established using applied economic models, with the option for individual project proponents to petition to use some other (presumably reduced) emission factor.

At a programmatic level, however, Identification of the factors influencing leakage magnitude and the most appropriate process for estimating risk is perhaps a task easier said than done. Schwarze et al. (2002) note that leakage from forest conservation projects (i.e., avoided deforestation and improved management) and afforestation projects will depend on both the particulars of the project and specific site and market conditions. Atmadja and Verchot (2012) likewise summarize leakage estimates for a variety of land use and non-land use activities using a variety of analytical approaches, finding an incredibly wide range in leakage estimates: -44% to 279% across activities, studies, and scenarios. Diaz et al. (2015) provide a comprehensive review of leakage approaches and estimates in the context of soil sequestration projects and, in doing so, report a range of 2%-89%, varying by space and over short versus long time periods.

Though it is difficult to select a single value that best reflects the leakage risk associated with the variety of activities potentially undertaken in Merced County, a decision tree-type approach provided by Air Resources Board (2015) provides a model for how one might winnow the list down to those activity configurations with the greatest risk. Key parameters of the decision tree include the previous use of the project area, the economic viability of the previous activity on the project area, and the expected magnitude of displacement of the previous activity. This process essentially follows the following logic: was something else there, was it commercially viable, and if so, how much are you encouraging to be produced off-site.

A similar conceptual map is adopted for activities here. Shown in Figure 1 is a hypothetical flow chart to guide leakage risk determination for management-based and avoided conversion activities. The first two decision points of this flow chart are predicated on the literature above, that there is a risk of secondary or market-induced leakage when an activity reduces the supply of some product, commodity, or service. The third meanwhile provides a check for the geographic reach of the affected market, using jurisdictional boundaries.

The fourth and fifth decision points attempt to reach some conclusion on the relative magnitude of leakage risk, but also reflect the practical difficulties that accompany the establishment of a standardized process for an activity-specific phenomenon. These decision points necessarily require simplification so as to make the flow chart applicable to the widest possible range of activities. An alternative would be to leave it up to the user to calculate specific leakage estimates unique to their particular situation. The flow chart reflects the former approach. The fourth decision point, for example, makes a distinction between short- and long-term impacts. Long-term shifts in production may elicit a greater market response than short term perturbations. The fifth decision point requires a balancing of opposing perspectives. Shifts in production that are small relative to the overall size of the market are likely to be associated with higher rates of leakage than those that comprise a larger share of the overall market (e.g., Murray et al., 2004). For the purposes of this analysis, one may assume that affected production represents a small share of the overall market. The implication of this assumption is that there may be little difference in leakage risk regardless of the magnitude of shift in production on lands affected by the activity. Instead, the flow chart implicitly rewards activities that minimize potential shifts in production by assuming a *de minimis* risk of leakage.

Alternatively, activities that may result in larger shifts in production are assigned default leakage risks from the literature. Leakage deductions for cropping systems approximated from estimates reported in Diaz et al. (2015), Wu (2000), and Roberts and Bucholtz (2005). Leakage deductions for forest systems approximated from estimates reported in Murray et al. (2004), Wear and Murray (2004). With fewer estimates located that specifically assess leakage in grazing, and vineyard and orchard systems, leakage rates are assumed to be similar to cropping systems for the first and similar to forest systems for the latter two.

It is important to again remind the reader that leakage is an intervention-specific phenomenon. There are inherent tensions between development of a simplified tool for evaluating the magnitude of leakage risk for whole classes of activities and derivation of specific estimates of leakage risk based upon the unique market and carbon parameters of the specific activity in question. For example, one reviewer of this review notes that total production of certain commodities in some California counties could represent a sizable share of the global market, complicating the assumption of small market share. But if one assumes a functional form like that derived by Murray et al. (2004) to characterize leakage risk, there is no market share threshold, *per se*, of when leakage becomes more of a concern, only a trend that leakage tends to increase as the share of total production affected falls. The figure below also does not capture the carbon density of affected land uses, nor does it fully consider the price elasticities of supply or demand. The value of the figure below should thus be seen in its conceptualization of the process for considering whether leakage is of concern, and less in the particular values assigned at the end.

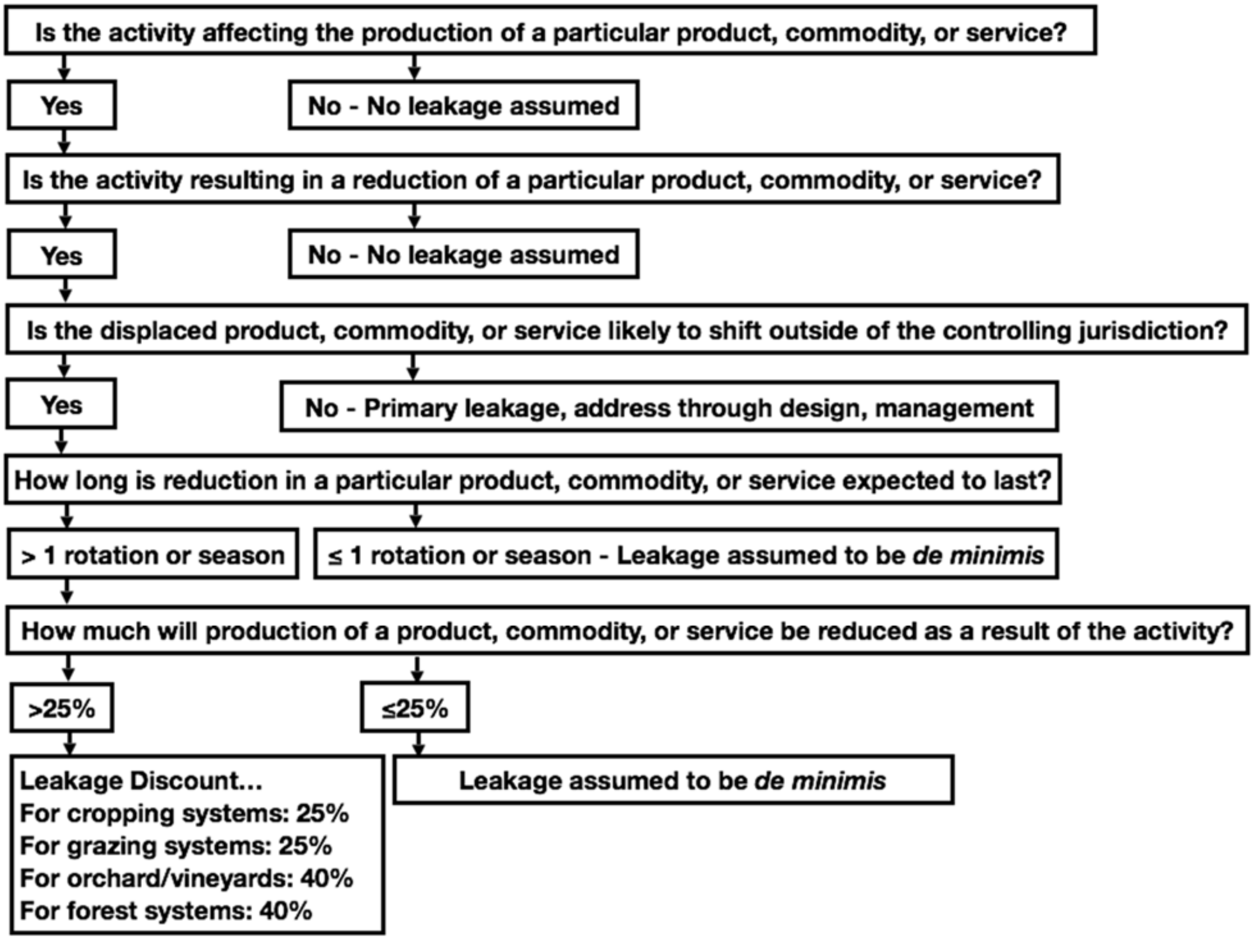

Figure 1. Flow chart to determine default leakage risk for land-based GHG management and avoided conversion activities in Merced County.

The above figure attempts to capture leakage risk from both management-based and avoided conversion activities. Avoided conversion requires a slightly different perspective than management-based decisions as any leakage will stem from the displacement of some new practice, meaning that leakage results from what is *not* done rather than what is. Consideration of such situations is further complicated when there is the potential to affect multiple product streams. For example, conversion of productive timberland to urban use involves the displacement of forest products that were produced on that site. Avoided conversion of that same timberland allows for forest production to continue, but risks displacing urban development to some other area. Strictly viewing the situation from a leakage perspective, however, it is only the latter set – displacement of the avoided use – that are considered here.

Avoided conversion is also complicated in that conversion pressures may stem from localized phenomena like urban development. In those specific cases where displaced activities are unlikely to shift outside of the jurisdiction in which the avoided conversion activity is taking place, it may be more appropriate to manage leakage risk through project design or through external programs operated by or at the county level, such as those encouraging infill development under SB375, the Sustainable Communities and Climate Protection Act of 2008.

Finally, note that the figure does not attempt to assess the carbon effects of land use or land management changes, including changes in relative carbon density on land where the activity takes place or the land to which production shifts. Rather, it attempts to focus the user on those situations where leakage may be of greatest concern and to identify a reasonable approximation of the magnitude of production shifts. As noted above, more precise estimates of leakage require activity-specific evaluation of supply and demand price elasticities, relative carbon densities of affected lands, and estimation of the relative share of the market affected (Murray et al., 2004), each of which is beyond the scope of this analysis.

The above flow chart is intended to address secondary, market-induced leakage. The literature suggests that primary, activity-shifting leakage is perhaps better handled through activity design and management at the jurisdictional (e.g., county) level. It is possible to minimize secondary leakage through activity design, as well. Approaches for both are reviewed briefly below.

Potential Risk Mitigation Mechanisms for Activities in Merced County, California

The literature is consistent in finding that leakage could be a serious risk to GHG project integrity, with multiple authors using strong language in their recommendations to address the phenomenon through program design or accounting (e.g., Alix-Garcia et al., 2012; Murray, 2008; Gan and McCarl, 2007; Murray et al., 2004; Schwarze et al., 2002). The literature also suggests that primary or activity-shifting leakage is a problem perhaps best addressed through project design, contracting, monitoring, and enforcement. Secondary or market leakage may be addressed somewhat by minimizing the reduction of a particular asset or commodity within the activity itself, but also requires some estimate of displaced storage or emissions that occur elsewhere. These approaches are further described below.

<u>Generalized Approaches for Mitigating Leakage</u>

Leakage is not only a function of the markets affected, but also the carbon content of the affected landscape. Owing to differences in resource attributes across the landscape, there is a need for careful consideration of where to undertake project activities so as not to enhance leakage (e.g., Renwick et al., 2015). In the present context, this implies that the opportunistic protection of a given area can yield higher degrees of leakage if the carbon content of that area is lower than landscape average.

Time is also important to consider. Aukland et al. (2003) argue that leakage should be assessed over the lifetime of the activity, as actor behavior may shift in response to changing market conditions. Sohngen and Brown (2004) find important differences in leakage estimates for projects of different durations.

Finally, the scale of program operation and monitoring is important to acknowledge. Murray (2008) notes anecdotally that increasing scale of coverage can help to reduce (but not eliminate) leakage, i.e. a shift from project-level to national accounting. Leakage is also reduced when expanding the total number of participating jurisdictions. In the absence of universal participation, it could be helpful to add a discount such that leakage penalty is reduced as participation increases (Murray 2008).

These considerations have been combined to various degrees in practice. For instance, IPCC (2000) implicitly endorses a two-stage approach: 1. Assign small monitoring area to projects with small potential leakage. 2. For projects expected to have larger leakage, expand monitoring area to encompass expected activities and then account for observed leakage either through monitoring of key indicators for evidence of leakage or assign (and update as needed) standardized adjustment coefficients. Henders and Ostwald (2012) meanwhile relate a “minimize then discount” strategy for leakage minimization, focusing on reducing the risks of leakage through appropriate project design (or exclusion) then accounting for any remaining risk through appropriate methodologies such as discounting.

Project Design Considerations for Addressing Leakage

Project design plays an important role in minimizing leakage (Auckland et al., 2003). Site selection, particular selection of sites with limited or no competing uses, is one means to address leakage (Schwarze et al., 2002). The inclusion of multiple products, commodities, or services so as to avoid displacement of production is another mechanism to address leakage through project design (Schwarze et al., 2002; Chomitz 2000). For example, Chomitz (2002) offers a solution that falls partly between that suggested by IPCC (2000) and Henders and Ostwald (2012), specifically either expanding the area incorporated in the project, thus internalizing any leakage, or designing the project in such a way as to counteract any leakage from the start (e.g., linking forest protection with intensification of grazing operations).

An alternative is to use an *ex post* true-up for leakage as proposed by van Oosterzee et al. (2012), in which no upfront discount is required but observed leakage must be addressed via payout to buyers by the project after-the-fact. van Oosterzee et al. (2012) argue that predicting leakage is difficult if not impossible ahead of time, and that creating a continuous liability to account for leakage creates an incentive for project proponents to continually work to minimize it. What the approach may lack, however, is certainty for those tasked with implementing the activities, perhaps reducing the incentive to undertake the activity in the first place.

Conclusion

The literature review and subsequent analysis undertaken herein demonstrates that leakage poses a potential risk to the GHG benefits yielded by land-based mitigation activities. To guide the development of processes and standards for land-based activities in Merced County, California, the analysis first characterizes those types of activities potentially facing the largest risk of leakage. Next, a simplified decision tree is developed to help guide users and decision-makers as to the situations under which the greatest risk of leakage may arise. Estimates of leakage rates are derived from the literature to further inform the process of evaluating the magnitude of leakage risk. The analysis concludes with a brief overview of mechanisms that may help to minimize leakage. Though it is hoped that the review and analysis will help stakeholders better evaluate leakage risk from land-based mitigation activities in Merced County, it is important to reinforce that the actual accounting and management of leakage requires attention to site-specific aspects of the activity, including market and carbon characteristics of the land affected and the specific set of planning or policy tools available to minimize or mitigate leakage risk. Such site- and project-specific analysis is beyond the scope of the current report.

Methods

This analysis is grounded in information derived from the peer-reviewed literature, so-called gray literature reports and discussion papers, and existing project-based accounting standards. Analysis began in January 2018 with a review of the extant literature on leakage. Owing to the ubiquitous nature of the term, analysis began with a review of known authoritative works on the subject, particularly those by Alig, McCarl, Murray, Sohngen, and Wear. The analysis then assessed papers cited by these initial authoritative works for their relevance to land-based activity leakage risk and/or accounting. Likewise reviewed for relevance to land-based activity leakage risk and/or accounting were papers citing these initial works, as listed on the Google Scholar record for each authoritative paper. The references in papers deemed relevant through this process were further reviewed for additional relevant sources. The analysis continued in this fashion until saturation, the point at which no new papers were identified for analysis.

A supplemental literature search was performed to assess the availability of adequate default leakage factors for either land-based activities generally or specific activities considered for use in Merced County. A Google Scholar search was conducted using the following terms: leakage "[activity]" "percent" "United States", where activity is the particular activity considered for deployment in Merced. Searches using these terms retrieved few additional studies (5) deemed to be relevant to this analysis beyond those returned through the general literature review above.

Though this literature screen returned a large number of potentially-relevant papers, the following review is limited to those papers deemed to be *most* relevant by the author owing to the limited time available for the analysis. The analysis should be therefore considered indicative of scholarship on the matter, but not an exhaustive or systematic review of the extant literature.

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Carbon Offsetting: An Efficient Way to Reduce Emissions or to Avoid Reducing Emissions?
An Investigation and Analysis of Offsetting Design and Practice in India and China

by

Barbara Kresch Haya

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Committee in charge:

Professor Richard B. Norgaard, Chair
Professor Michael O'Hare
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Abstract

Carbon Offsetting: An Efficient Way to Reduce Emissions or to Avoid Reducing Emissions?
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Carbon trading is being implemented on international, national and sub-national scales in most places where greenhouse gas (GHG) emissions targets are enacted. The appeal of carbon trading is efficiency, lowering the cost of climate mitigation by allowing the market to find the least expensive sources of reduction. In this dissertation I probe the assumptions that carbon trading is efficient and effective through grounded case study.

A multi-year study on how the Kyoto Protocol's Clean Development Mechanism (CDM) – the world's largest carbon offsetting program – is working in practice in the Indian power sector (Chapter 2) documents large uncertainties associated with the emissions reduced by the program. This uncertainty has resulted in large numbers of CDM projects that do not actually reduce emissions (are "non-additional") and regulatory uncertainty that undermines the effectiveness of the program in supporting new projects. In the medium- and long-term, even if the quality of offsetting projects can be assured, the purported efficiency of offsetting must be weighed against ways that offsetting at large scale makes international climate change cooperation more difficult over the next decades.

There has been a lot of interest in continuing offsetting by ensuring that the credits generated represent real emissions reductions. Chapter 3 examines the prospects for developing a more rigorous "additionality test" for filtering out proposed CDM projects that are business-as-usual and therefore do not represent real emissions reductions under the program. Through in depth case studies of additionality testing for wind, biomass and hydropower projects in India, I conclude that at today's carbon prices there is no accurate verifiable indicator of whether CO_2 reduction projects would be built without the CDM.

Chapter 4 probes the effectiveness of carbon crediting in incentivizing emissions reductions. A focused look at the history of support for bagasse cogeneration in India reveals that a range of shifting barriers have impeded the development of this cost effective technology. A carbon price alone would not have overcome the barriers to this technology, and parallel support efforts were needed to spur this technology.

Post-2012 climate change agreements and legislation include provisions for replacing CDM additionality testing with standardized project eligibility criteria and indicate a shift away from project-based offsetting towards offsetting on a sectoral level as ways to retain the efficiency of offsetting, but avoid the current problems with the CDM. I examine this range of proposals for reforming or replacing the CDM with a study of the design of a sectoral crediting programs in the cement sector in Shandong province in China. This study indicates that for most

conceptions of sectoral crediting programs, the problems with the CDM documented in Chapters 2, 3 and 4 risk being even worse when offsetting is implemented on a sectoral level.

I conclude with a brief discussion of how some of the inefficiencies of offsetting may feature in carbon trading generally by tracing parallels between the design and implementation of the CDM and California's Low Carbon Fuel Standard. I end with a policy discussion of the political space within which offsetting is being negotiated internationally, and within the US, and alternatives to the CDM and offsetting that might fulfill political and environmental goals together.

Table of Contents

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Chapter 1. Introduction

> "And let me be clear on this point. In the long run, market-based solutions will prevail... we must put a price on carbon."
>
> -- Anders Rasmussen, Former Danish Prime Minister, at Climate Change: Global Risks, Challenges and Decisions Conference, Copenhagen, 10-12 March 2009

> "We are going to do this by allowing the market to determine which alternative vehicle fuels are the most cost effective and energy efficient."
>
> -- Arnold Schwarzenegger, speech given when signing the Executive Order establishing California's Low Carbon Fuel Standard on 18 January 2007, Sacramento

The term "market-based" is being used as an adjective to imply that an environmental regulation is efficient, effective and leaves decision-making in the hands of the private sector rather than the government. In the context of climate change policy, "market-based" most often refers to the mechanism of carbon trading under a cap and trade program, and not to its two main alternatives: direct regulation and/or carbon taxes which are not currently viewed as politically feasible in the EU and the US. Cap and trade with offsets is being implemented on international, national and sub-national scales in most places where greenhouse gas (GHG) emissions targets are enacted. Cap and trade with offsets is the backbone of our global climate change regime under the Kyoto Protocol, and the backbone of EU climate policy under the EU Emissions Trading Scheme (ETS), California's climate change regulation, regional agreements among states and provinces in northeastern and western US and Canada, and regulation proposed at the national level in the US and being considered for adoption in China. It is a huge global experiment in environmental regulation, based on economic theory and the limited experience of sulfur dioxide and nitrogen oxide emission allowance trading in the US, for which the emissions were easier to monitor and the results were mixed (e.g. Farrell 2001).

The theoretical appeal of cap and trade is efficiency. It sets a cap on emissions, and lowers the cost of compliance by purportedly allowing the market to find the least expensive sources of reduction. In this dissertation, I probe the assumptions that carbon trading is efficient and effective. I contribute a multi-year study on the effects of the world's largest offsetting program – the Clean Development Mechanisms (CDM) – established under the 1997 Kyoto Protocol. I find that the CDM is creating large numbers of credits that do not represent real emissions reductions, and that the CDM is having no more than a weak influence on project development decisions for most project types. Efforts to reform the CDM or replace it with another offsetting program are hindered by structural hurdles that make offsetting extremely difficult to regulate. These findings question the overall approach being taken to control GHG emissions. Given that global emissions scenarios with even medium chances of staying below a two degrees increase in global average temperatures show global emissions beginning to decline in the next five years (Intergovernmental Panel on Climate Change 2007, Meinshausen et al 2009), we do not have time for false solutions.

Cap and trade establishes emissions caps on emitters, such as countries under the Kyoto Protocol,[1] or power plants and factories under domestic cap and trade programs, and allows those capped entities to trade emissions credits. The cap regulates the outcome of concern – emissions – and lets the regulated entities decide how to control their emissions. Trading should lower the cost of reductions. Instead of requiring each regulated entity to meet emissions standards, emissions can be reduced in the regulated facilities where reductions are least expensive, and carbon credits can be sold to facilities where reductions are more expensive. Offsets extend the trading regime beyond the boundaries of the capped regions or sectors. The Kyoto Protocol's Clean Development Mechanism (CDM) allows countries, or firms within countries, to partially meet their GHG emissions reduction obligations by reducing emissions in developing countries. The most common project types under the CDM are hydropower, wind power, biomass energy, and methane avoidance such as with landfill gas capture. Projects that reduce or burn industrial gases, like HFCs from refrigerant manufacturing facilities, are fewer in number, but generate approximately one third of all CDM credits because of the high potency of these gases as greenhouse gases. In theory, the CDM improves the efficiency of the Kyoto Protocol by allowing emissions to be reduced wherever in the world it is least expensive to do so.

The main hurdle to the CDM, and to offsetting generally, is the need to assure credited activities are "additional." Measuring emissions reductions under an offsetting program is inherently more difficult than under a cap and trade program. Under cap and trade, reductions are estimated by comparing total emissions during the compliance period with emissions in a past year. If current emissions are lower than past emissions, emissions were reduced. Measuring emissions reduced by an individual offset project requires comparing the emissions from the project with a counterfactual scenario of what would likely have happened in the absence of the offsetting program – a hypothetical future scenario that is inherently uncertain. The most difficult task in determining an appropriate counterfactual scenario is assessing whether the credited activities would not have gone forward had it not been for the ability to earn credits. The underlying justification for the CDM is that industrialized countries can buy CDM credits in place of reducing their own emissions because they *cause* the equivalent emissions to be reduced in a developing country. The CDM therefore requires each project applying to generate carbon credits under the CDM to demonstrate that it is "additional," that is, that it only went forward because of the additional revenues from the sale of carbon credits, and would not have been built otherwise. Verifying that an activity is additional is difficult because it involves assessing the considerations of project developers under a counterfactual scenario.

In the chapters below, I examine the efficiency and effectiveness of carbon offsetting through a grounded study of how the CDM is working in practice in the Indian power sector. I assess the influence the CDM is having, factors that limit that influence, and possible ways to improve the CDM's outcomes through reform or replacement. This research focuses on wind, biomass and hydropower in India with a more focused study of the history of the development of bagasse cogeneration (the generation of electricity and steam from sugar cane waste). I find that additionality testing is failing to prevent large numbers of non-additional projects from registering under the CDM. At the same time, additionality testing is compromising the ability for the CDM to incentivize the building of new projects by introducing substantial uncertainty

[1] The Kyoto Protocol, adopted by countries in 1997 and entered into force as a legally binding agreement in 2005, requires industrialized countries to reduce there emissions as a block to 5.5% below their 1990 levels during 2008-2012. Emissions caps vary country to country, and compliance credits may be traded between countries. See http://unfccc.int/kyoto_protocol/items/2830.php (Last accessed on 16 December 2010).

into the CDM application process. In other ways, contradictions in the basic structure of the CDM lead to a systematic over-crediting emissions reductions.

Proposals for reforming or replacing the CDM largely fall into three categories: (i) strengthening additionality testing procedures, (ii) replacing project-by-project additionality testing with standardized eligibility criteria whereby whole categories of projects would automatically be eligible to generate credits under the CDM, and (iii) crediting reductions on a sectoral scale, rather than for individual projects. The most common conception of the latter category would establish a sectoral baseline, for example, some number of tons of CO_2-equivalent emissions per ton of cement produced, and would generate credits if emissions in the entire sector are below that baseline. I examine each of these options in the chapters below. I show that additionality testing for individual projects is inherently inaccurate with an examination of wind power, biomass power and hydropower projects in India, and therefore will not be sufficiently improved with strengthened additionality testing procedures. In a different context – the cement sector in Shandong province in China – I perform a policy design analysis covering the other two categories of proposals for CDM reform and replacement. I explore how various sector-based crediting approaches might improve upon the outcomes of the CDM in terms of effectiveness and efficiency, and conclude that sector-scale crediting risks expanding the CDM's problems unless carefully and narrowly designed. To draw more general conclusions about conditions that compromise the efficiency and effectiveness of carbon trading broadly, I end by highlighting some noteworthy similarities between the CDM and California's Low Carbon Fuel Standard (LCFS) based on my experience working on the design of this California program.

The efficiency and effectiveness of a carbon trading program, whether cap and trade or carbon offsetting, depends on a number of factors. Can emissions reductions be measured with reasonable accuracy so as to ensure that the target is met? Carbon trading is only as effective as the ability to measure emissions reduced by the activities covered under the program. Uncertainties in the quantity of emissions reduced mean uncertainty as to whether the target is met. If uncertainties in emissions measurements are greater than the differences in emissions between competing activities, the program might be sending the wrong price signal, increasing emissions. To what extent might the program create perverse incentives, direct or indirect, that lead to emissions increases? Does the program create incentives that match what is needed to overcome barriers to low carbon technologies and other changes that reduce emissions? How high are the program's transaction costs compared to other policy options? Does the program create strong enough and long-term enough market signals to incentivize activities needed to achieve deep reductions over the next decades? Is the program accompanied by public sector actions supporting activities needed for long-term mitigation, for which the net social benefits are high, but for which the costs to any one private sector entity are much higher than the benefits to that entity, such as the building of infrastructure and basic research? A result of this research is that simply creating a price signal is not always sufficient or productive. A carbon price functions within the limitations of our regulatory institutions, and the context of the specific barriers to, and opportunities for, reducing emissions in specific sectors in specific regions. Careful analysis of this context is needed in the design of carbon trading programs and any climate policy.

Offsetting is a lynchpin of current and proposed international climate change agreements. It is both the main cost control mechanism offering industrialized countries access to relatively inexpensive compliance options, especially important if mitigation costs turn out to be substantially higher than anticipated. It is also the main source of the financing promised to developing countries for climate change mitigation. The CDM is fulfilling these political goals while weakening the environmental outcome of our international climate change agreements.

In response to heavy criticism from both environmental and business communities, negotiations are going forward over reforming or replacing the CDM under post-2012 climate change agreements. These negotiations are happening within a narrow political space of what is acceptable to countries in the global North and South. Researchers are seeking ways that the CDM can be reformed or replaced so that it can continue to fulfill its important political goals with greater environmental integrity. I show that most configurations of each of these options continue to risk the large scale over-crediting of emissions reductions. An international offsetting program with lower risk of over-crediting would need to be relatively narrow and conservative in scope and carefully regulated, requiring political will that has not yet been demonstrated.

We were recently reminded that markets need regulation to function with the collapse of the US mortgage market following the deregulation of the US financial industry triggering a global financial crisis. Much more is at stake with regulation of the carbon market. We are entrusting the carbon market with the stability of the earth's climate for many generations to come. Before establishing such a market we need to be confident that it is regulatable and does the job needed, not based on theory, but on grounded cautious analysis. The analysis contained herein, grounded in the Indian power sector, with analysis in the Chinese cement sector, shows that offsetting is inherently difficult to regulate, adds uncertainty to the emissions outcomes from a cap and trade program, and unless very carefully and conservatively designed, undermines the strength of a cap and trade program.

1. CONTRIBUTIONS TO THE LITERATURE

1.1. The efficiency and effectiveness of international carbon offsetting

This dissertation addresses practical policy questions about the use of offsets and design of offsets programs to meet greenhouse gas (GHG) emissions targets. Offsets have been included in cap and trade programs on the basis that they lower the cost of compliance, improve the efficiency of the program and support low carbon development in developing countries.

Some researchers describe the CDM as successful in supporting sustainable development in developing countries without questioning the environmental integrity of the credits it generates (e.g. Gao et al 2007). Expanding the CDM has been proposed so that it can better reach a wider range of countries (e.g. Byigero et al 2010) and sectors (e.g. Winkler & Es 2007). Economic analyses estimate that offsets substantially lower the cost of cap and trade regulation. For example, it is estimated that offsetting could lower the cost of California's climate legislation (AB 32) by 78% (California Air Resources Board 2010b, table ES-2).

Critical studies estimate the proportion of registered CDM projects that are truly additional as 60% of projects registered by 2007 (Schneider 2009) and "a fraction" of projects registered by 2008 (Wara & Victor 2008). Analyses show that the additionality of wind projects (He & Morse 2010) and natural gas projects (Wara & Victor 2008) in China are highly questionable. Others have documented that uncertainty in the benefits to project developers from the CDM are undermining the CDM's ability to affect project development decisions (Duan 2008). With regard to HFC reduction projects from refrigerant manufacturing plants, the CDM is much more expensive than it would cost to pay for the reduction technology directly such as through a climate fund (Wara & Victor 2008), and the CDM creates perverse incentives for companies to create more pollution in order to gain more revenues from destroying it with a CDM project (CDM Watch via Det Norske Veritas Certification AS 2010, Wara & Victor 2008).

My research supports these CDM critics with a grounded multi-year study in the Indian power sector. I provide evidence that the majority of CDM projects are non-additional and that the CDM's effects are compromised by the uncertainty associated with its benefits. I raise additional issues associated with the systematic over-crediting of emissions reductions, and the effects of large-scale crediting on international cooperation towards deep reductions over the next decades.

Some researchers who have written critically on the CDM suggest solving the additionality problem by tightening the CDM's additionality testing procedures (e.g. Michaelowa 2010, Schneider 2009, Wara & Victor 2008). I perform a detailed examination of project development considerations for wind power, biomass power and hydropower projects in India and conclude that a reasonably accurate additionality test is infeasible for most CO_2 reduction projects at current carbon prices.

Replacing project-by-project additionality testing with standardized project eligibility criteria has also been proposed (e.g. Sterk 2008) and language along these lines is included in international climate change negotiating texts (UNFCCC 2010: 41 para 9) and domestic climate change legislation in the US (American Clean Energy and Security Act 2009, California Air Resources Board 2009). A shift from project-based to sector-scale crediting has been proposed by some CDM proponents as a way to expand the effects of the CDM and by some CDM critics as a way to replace the CDM with something more effective (e.g. Schmidt et al 2008). Sectoral crediting programs are being proposed for inclusion in California's cap and trade program (California Air Resources Board 2009), US federal legislation (American Clean Energy and Security Act 2009), EU climate policy (European Commission 2010: p. 8 & footnote 19), and post-2012 international climate change agreements (Belgium and the European Commission on behalf of the European Union and its member States 2010).

A variety of concerns have been raised about sectoral approaches. Concerns have been raised about the effectiveness of creating financial incentives for government action, especially when payments are made for reductions after they have been achieved rather than up front (Sterk 2010). Some discuss the challenges of avoiding over-crediting emissions reductions, particularly with regard to measuring emissions reduced by government policies and programs (Millard-Ball 2010b, Sterk 2010) and estimating a business-as-usual sectoral baseline (Millard-Ball 2010b, Schneider & Cames 2009), and the potential for creating perverse incentives for governments to refrain from action in order to generate more credits in the future (Ellerman et al 2008, Schneider & Cames 2009). Host country capacity to perform the necessary monitoring, reporting and verification has been raised as an important challenge to sectoral-scale crediting (Cai et al 2009, Center for Clean Air Policy 2010). Though many of these studies discuss similar concerns, their conclusions differ widely. Some suggest that sectoral crediting should be avoided generally (Sterk 2010) or for specific sectors (Millard-Ball 2010a) and others conclude that sectoral crediting is promising if carefully designed (Center for Clean Air Policy 2010, Schmidt et al 2008, Schneider & Cames 2009). I offer a study of the design of a sector-scale offsetting program in the Shandong cement sector, including standardize eligibility criteria as one possible variation of a more sector-scale approach. This work supports some of the concerns raised, and raises others. Chapter 5 of this dissertation may be the most detailed study performed so far on the design of a sectoral crediting program for a specific sector.

1.2. The neo-liberalization of environmental regulation

Markets for environmental pollution are emerging in all areas of environmental regulation, as a part of a trend towards the neo-liberalization of environmental regulation. Offsets are included in regulation in the US under the Clean Water Act, the US Endangered Species Act, the Canadian Fisheries Act, and in environmental regulations in the EU, Switzerland and Brazil (ten Kate et al 2004). Under the 1972 US Clean Water Act, developers given permission to build on wetlands that are unable to reduce their impact to zero, must compensate for that damage by restoring other wetlands with equivalent ecosystem function. In 1991, a tradable wetlands crediting system emerged crediting wetland restoration from established wetland "banks" (see Robertson 2004, 2006). In 2005 there were around 400 existing wetland "banks" around the US and another 200 being proposed (U.S. Army Corps of Engineers 2008). Similarly, the US Endangered Species Act contains a provision that has allowed for species banking – a developer can harm endangered species if they protect that species elsewhere. Payment for Environmental Services programs create international markets for environmental services such as forest conservation (McAfee & Shapiro 2010). Such payments have gained dominance in discussions over environmental protection in some places. In the 2005 international climate change negotiations in Montreal, Papua New Guinea and Costa Rica proposed a new program that would provide funds to help developing countries prevent deforestation, the form of which has been actively negotiated since. This program, called Reducing Emissions from Deforestation and forest Degradation (REDD), could be supported by an international fund, carbon trading, or some combination of the two. Study of the effectiveness of carbon offsetting has implications for the direction of environmental regulation in a wide range of areas.

The processes of enactment and implementation of two different programs involving carbon trading – CDM on a global scale and the LCFS in California vehicle fuel sector – are surprisingly similar. The CDM and California's LCFS were both enacted as one- or two-pages of legal text (Office of the Governor of the State of California 2007, UNFCCC 1997) before fundamental design issues had been worked through. In the process of implementation and program design, it became clear that regulators faced substantial uncertainties in estimating emissions reductions from both of these programs. Questions were raised about non-additional projects registering under the CDM (Haya 2007, Haya 2009, He & Morse 2010, Michaelowa & Purohit 2007, Schneider 2009, Wara & Victor 2008). In an exciting period of rapid academic discovery, research documenting large uncertainties in measuring lifecycle emissions from biofuels emerged, particularly around its indirect land use effects (O'Hare et al 2009, Plevin et al 2010, Searchinger et al 2008). Policy makers and academics working on both programs responded with calls for more research to determine the "right" numbers and procedures without questioning whether carbon trading itself is appropriate in these contexts. Many of the strongest critics of additionality testing under the CDM called for strengthening additionality testing criteria (e.g. Michaelowa 2010, Schneider 2009, Wara & Victor 2008). A flurry of research over the last few years has focused on developing models that could home in on the indirect land use effects of biofuels (e.g. Al-Riffai 2010, Dumortier 2009, Fritsche 2010, Hertel 2010, Tyner 2010). The California Air Resources Board is designing its LCFS regulation with the expectation that a reasonably accurate value is attainable with more study. It is not clear that this is a reasonable expectation (Plevin et al 2010). Calculating emissions reductions and assessing additionality under the CDM and calculating lifecycle emissions of vehicle fuels and the over all design of the LCFS are very complex. This complexity makes it difficult for the public to understand and monitor the effects of these two programs.

We are now seeing the same process repeated in the context of sectoral crediting approaches. As mentioned above, a number of studies examine how sectoral crediting could broadly work (e.g. Schmidt et al 2008, Schneider & Cames 2009) but few studies focus on details of implementing a sectoral program in a specific sector and country (Millard-Ball 2010a). Yet sectoral crediting is being written into draft international negotiating text and into domestic legislation based on the assumption that it can work. Economic theory belies much of the political rationality advancing these policies. We have seen this before.

The history of international development assistance is full of programs based on neo-liberal economic theory that fail on the ground (Escobar 1995, Scott 1999). Joseph Stiglitz, in his 2003 book *Globalization and its Discontents*, criticized the International Monetary Fund (IMF) for following neo-liberal policies with a religious fervor, even though history has shown that these policies have harmed economies more than helped them. For example, Malaysia did not suffer as much as many other Asian countries following the Asian Financial Crisis because it did *not* follow the prescriptions of the IMF prior to the crisis (Stiglitz 2003). Ha-Joon Chang, in his book *Kicking Away the Ladder*, describes multiple periods over the last few centuries when wealthier countries have pressured poorer countries to open their borders to trade based on economic arguments that free trade brings economic growth. These policies resulted in the extraction of wealth and market power from the poorer countries to the wealthier countries. Free trade policies were promoted based on claims that they result in economic growth even though almost all of today's industrialized countries developed with strong policies protecting domestic industries (Chang 2002).

In another global experiment in energy policy, the World Bank pressured developing countries around the world to restructure and privatize their power sectors (World Bank 1993). Developing countries were asked to follow a blueprint of reforms modeled after the restructuring process in the UK, US and Norway (Dubash 2002, Williams & Ghanadan 2006). The Asian Financial Crisis of 1997-98 and the California electricity crisis in 2000-1 shook confidence in the restructuring process worldwide (Williams & Ghanadan 2006). By a few years later the World Bank revised its restructuring blueprint, calling for more considered power planning appropriate for each country, (while also keeping many underlying objectives intact) (ibid.). In the mean time, there was a large transfer of assets from governments in the South to private companies in the North, with notable examples of independent power producers (IPPs) (Eberhard & Gratwick 2007, Phadke 2009, Woodhouse 2006). For example, Enron sold power to Maharashtra state in India at extremely expensive rates from its notorious Dabhol project, straining the Maharastran State Electricity Board financially (Dubash 2002, Phadke 2009). The transfer of wealth from the public to the private sector also happened in industrialized countries. Enron and other power generators are estimated to have extracted on the order of $4 billion from California during 1998-2000 by exercising market power in California's partially restructured market (Borenstein et al 2002), in part through the strategically closing power plants for "maintenance" during peak periods contributing to large price spikes.

The literature on development aid provides many other examples of projects failing because they are designed without adequate understanding of the local context in which they are carried out (Ferguson 1994, Scott 1999). Solar panels sit idle on village rooftops because solar panel programs lack attention to maintenance infrastructure, training for panel owners, and the availability of parts (Green 2004, Martinot 2002). International finance institution prescriptions have been copied and pasted from one country to another based on technical analysis that ignores the actual economy conditions and the local political context in which the prescriptions are carried out, resulting in negative effects (Ferguson 1994).

How is it that with growing criticism about the environmental outcomes of the CDM, that policy-makers and researchers enthusiastically support sectoral approaches prior to careful grounded analysis, potentially replacing one loophole in our international climate agreements with another even bigger loophole? Sectoral offsetting is being promoted before we can be assured it reliably reduces emissions, just as were both the CDM and the LCFS. We must ask, what *does* this project do (Ferguson 1994, Ghanadan 2008, Mitchell 2005)?

Offsetting does several things. First, as mentioned above, offsetting fits a narrow political space in international climate change agreements, providing industrialized countries and their regulated industries with inexpensive compliance options, and providing developing countries with funds towards mitigation activities, in a manner that is acceptable by major negotiating countries. Second, offsetting provides a way to appear to address environmental concerns with technological solutions that do not require the fundamental societal changes that are needed (McAfee 1999, Spash 2010). Third, using "market-based" as a positive adjective supports a worldview that even environmental regulation, which has been the responsibility of public sector, is better done by private industry and the market. It supports a neo-liberal view that the role of government should be minimized and that decision-making is best left in the hands of consumers and producers, serving the interests of those benefiting from less government oversight and a wider reach of the market (McAfee 1999).

2. METHODS

The research for this dissertation involved semi-structured and unstructured interviews, CDM project document review, analysis of CDM project financial spreadsheets, analysis of the UNEP Risoe database of proposed and registered CDM projects,[2] and participant observation.

I started the research for this dissertation in May 2004 with interviews exploring the influences that enabled and limited the dissemination of bagasse cogeneration (the efficient generation of electricity and steam from sugar cane waste) in India. My two co-researchers[3] and I sought to understand the barriers to the dissemination of bagasse cogeneration in India, and the effects of international and domestic efforts to overcome these barriers and to support this technology. This research involved visits to nine sugar mills in Maharashtra and Tamil Nadu states in India, review of project documentation from the support programs analyzed, and semi-structured interviews with individuals involved in bagasse cogeneration projects and support programs. We interviewed individuals from various levels of Indian government, non-governmental organizations (NGOs), multilateral agencies, energy consulting firms and research institutions in New Delhi, Pune, Chennai and Bangalore.

Since it is much easier to understand what happened than why it happened, and oftentimes individuals deeply involved in a project have misconceptions of the influences on

[2] UNEP Risoe CDM/JI Pipeline Analysis and Database, September 1st, 2010 http://www.cdmpipeline.org/

[3] I conducted this research as a part of a team project funded by the UC Berkeley-UNIDO "Bridging the Divide" Fellowship with two UC Berkeley PhD students – Malini Ranganathan and Sujit Kirpekar.

their own decisions, we relied on triangulation and scepticism to come to our findings. With triangulation, we used multiple varied sources to support our conclusions. With scepticism, we constantly questioned our understanding, looking for other possible explanations, and asking more questions until we were confident in our findings.

These early interviews raised doubts about the influence the CDM is having on project development decisions and the additionality of proposed CDM projects. The largest share of my PhD research explored and documented the influence the CDM is having (and is not having) in the Indian power sector, and ways the mechanism might be restructured or replaced to have a stronger influence. I spent twenty additional months in India during 2006 through 2009. In my second research visit to India in 2006, a picture quickly emerged of the CDM as crediting many business-as-usual projects and having little influence on the development of new projects. I returned to India two more times, for ten months in 2007-8 and three months in 2009, to probe these findings more deeply and gather evidence. Since the CDM's rules and procedures became stricter after its first two years, the chapters herein are based only on the interviews conducted during 2007-2009.

Chapters 2 and 3 on the CDM in the Indian power sector are based on: (i) over 75 interviews conducted in India during 2007 to 2009, (ii) an analysis of project documents from 80 CDM projects registered in India and China, and (iii) analysis of the UNEP Risoe CDM project database containing information about all projects currently registered under the CDM and in the application process.

I conducted semi-structured and unstructured interviews with experts involved in all stages of CDM project development (mostly in India and several at international conferences), including project developers from a range of project types (32 individuals), CDM consultants (14), validators from four out of the five largest validation firms in India (hired to audit projects applying for CDM registration, 7), carbon traders (5), employees of banks lending to renewable energy projects (2), government officials (2), members of the CDM governance panels (2), and researchers involved in renewable energy and hydropower development and the CDM (11). Interviewees were identified in three ways. Many of the interviewees were participants at carbon and climate conferences and workshops, providing the opportunity for informal discussions, sometimes over several days, and the chance for more frank discussions than would typically happen at a meeting in someone's office. I sometimes arranged follow-up interviews after a conference or workshop. Second, snowball methods were used whereby interviewees recommended other key experts. In addition, I identified and contacted key individuals at the largest validation and CDM consulting companies. Questions focused on the decision-making processes determining the financing and building of wind power, biomass power, hydropower and fossil fuel projects in India, including government involvement, regulatory processes, and factors affecting the decisions of individual lenders, investors and developers. I also asked experts general questions about their views on the influence the CDM is having in India, and how the CDM can be improved to more effectively promote renewable energy in India.

I analyzed CDM project documents for the additionality arguments used to register all of the large (over 15 megawatt (MW)) wind, biomass and hydropower projects registered by the CDM in India since 2007, and the 20 most recently registered hydro projects in China as of December 2009, totaling 80 projects (see Table 1.1). I chose to review only "large" projects since the additionality testing procedures for projects above 15 MW are more rigorous than for "small" projects. I chose to review only projects registered from 2007 because additionality has gradually been strengthened, and was particularly weak during the first two years of the CDM as the market was being built. I chose the three most numerous project types in India, and hydropower in China because it is by far the most numerous project type in the CDM pipeline, comprising 17% of all projects. A focus on several project types allowed for a more comprehensive analysis than would be possible if projects were randomly chosen. The four project types represent one third of all projects registered under the CDM and applying for registration worldwide when small-scale projects are also taken into account.

Table 1.1: Projects analyzed

	Projects analyzed	Projects in the CDM pipeline (registered & applying; large & small)	
		Total number of projects*	Percent of all projects in CDM pipeline*
Wind in India	25	416	8%
Biomass in India	19	315	6%
Hydro in India	16	161	3%
Hydro in China	20	942	17%
TOTAL projects of these four types	80	1834	34%
TOTAL projects in the CDM pipeline		5444	

* UNEP Risoe CDM/JI Pipeline Analysis and Database, September 1st, 2010 http://www.cdmpipeline.org/

I also had the opportunity to attend four annual international climate change negotiating sessions[4] and two CDM Coordination Workshops in Bonn[5] between 2005 and 2009. At these conferences, and to a lesser extent at climate change and CDM conferences in India, I was able to talk to validators (CDM project auditors), consultants and project developers from other countries, as well as CDM governance panel members familiar with CDM projects from many countries. The statements commonly made by Indian CDM and energy practitioners were very similar to statements made in my discussions and interviews with individuals working in a range of countries.

As an active member of the Climate Action Network flexible mechanisms working group[6] at the international climate change negotiating sessions, I was able to talk with the CDM negotiators from various country delegations to understand their positions on the CDM and CDM reform. Understanding of the politics of CDM reform informs the policy conclusions discussed below.

Chapter 5 presents the results of a design analysis of a sectoral crediting program in the cement sector in Shandong province, China. This analysis differs from my study of the CDM in two important ways. The program does not yet exist, so there are no outcomes to study, and I did not visit China or conduct interviews. I relied on literature, and more so, on the substantial expertise on the Chinese cement sector of my colleagues in the Lawrence Berkeley National

[4] Conferences of the Parties to the UNFCCC in 2005 in Montreal, 2007 in Bali, 2008 in Poznan, and 2009 in Copenhagen

[5] I attended as a member of the Roster of Experts for the CDM Methodology Panel.

[6] The Climate Action Network is a network of over 500 environmental NGOs worldwide that are active in the international climate change negotiations and domestic climate change policy. This network is well organized with working groups that follow, analyze, develop consensus positions on and weigh in on key negotiating issues.

Laboratory (LBL) China Group with whom I worked on this design analysis. I first created a typology of design options from the literature on sectoral crediting with the Chinese cement sector in mind. We then thought through the pros and cons of each design option as they apply specifically to the Shandong cement sector. This analysis of the pros and cons of different options was modeled after the design analysis process in which I participated for California's Low Carbon Fuel Standard (LCFS).

In 2007, I worked with a team of professors and graduate students from the University of California at Berkeley and at Davis that was tasked with a design analysis of California's LCFS for the State of California. This process involved laying out key design decisions and options, and active discussion, debate and drafting on their pros and cons and our recommendations on each. The process also involved discussions with program stakeholders. Through this process I witnessed certain similarities between the CDM and the LCFS that I discuss in the Conclusion to this dissertation.

3. IN WHAT FOLLOWS

Chapter 2 – *Measuring Emissions Against an Alternative Future: Fundamental Flaws in the Structure of the Kyoto Protocol's Clean Development Mechanism* – shows: (1) Large numbers of CDM projects are "non-additional" (would have gone ahead regardless of support from the CDM) and therefore do not reduce emissions; (2) Uncertainty associated with the benefits of the CDM compromises the CDM's influence on project development decisions; (3) The CDM systematically over-credits emissions reductions; (4) Even if the environmental integrity of carbon offset credits could be assured, the large-scale use of carbon credits generated in developing countries to meet industrialized country emissions targets undermines climate change mitigation over the next decades. Uncertainties involved in measuring emissions against a counterfactual scenario mean that offsetting risks weakening the effectiveness of global climate change agreements to control greenhouse gas emissions to the extent that they are used.

Three proposals for reforming or replacing the CDM have received the most attention in international policy discussions. These are (i) making project-by-project additionality testing more accurate with more rigorous additionality testing procedures, (ii) replacing project-by-project additionality testing with standardized eligibility criteria, such as project, type, size, location and efficiency level, that would automatically allow projects fulfilling the criteria to generate credits under the CDM, and (iii) replacing the CDM with approaches that credit reductions on a sector-scale, with a range of such proposals under discussion. The first option is the topic of Chapter 3 and the two others are analyzed in Chapter 5.

Chapter 3 – *Can the CDM's Investment Analysis Accurately Test Additionality? A Focused Look at Wind Power, Biomass Energy and Hydropower Projects in India*. The "investment analysis" is considered the most accurate way to filter projects that are only able to go forward because of the additional financial boost from carbon credits sales. The investment analysis is used to demonstrate that a project is not financially viable without carbon credits, by showing that the project's financial returns, most often in terms of internal rate of return, are below a viability benchmark for the project. I perform sensitivity analyses on the financial projections used in the investment analyses of wind, biomass and hydropower CDM projects in India. Even with the best case technology for an accurate investment analysis – wind projects in India for which the main costs and revenues are documented in contracts before construction begins – cost and revenue assumptions can still be gamed to show that some financial viable projects are not viable. For most other project types there is much more room to manipulate cost and revenue inputs. Even if financial projections were assumption-free, the viability benchmark against which project financial return is compared is highly sensitive to assumptions. Large hydropower in India is inappropriate for additionality testing because development decisions are mainly made by a government process, and because tariffs are adjusted to guarantee hydropower developers a pre-determined return on their equity investment, rendering the IRR analysis relatively meaningless. I conclude that an accurate project-by-project additionality test is infeasible for CO_2 reduction projects.

Chapter 4 – *Barriers to Sugar Mill Cogeneration in India: Insights into the Structure of Post-2012 Climate Financing Instruments* – examines the effectiveness of the CDM through a focused study of the history of the development of a single technology in India – the generation of electricity and steam from sugar cane waste called bagasse cogeneration. We examine the barriers this technology has faced over time, and how well a range of international and domestic efforts have helped to overcome these barriers. We compare how well the CDM helped address the barriers to bagasse cogeneration compared to more traditional fund-based approaches such as projects of international financial institutions like the World Bank and grant agencies like USAID and the Global Environmental Facility. Bagasse cogeneration has faced layers of informational, technical, regulatory and financial barriers that have changed over time, and differed between the private and cooperative sugar sectors. We find that each of the programs designed to support bagasse cogeneration had a role to play in enabling the bagasse cogeneration currently installed, and no single program would have been successful on its own. Any effort to exploit the remaining estimated national potential for high efficiency bagasse cogeneration will need to address the special financial and political conditions facing cooperative mills. I would like to highlight two conclusions from this chapter. First, some barriers to bagasse cogeneration needed directed efforts designed to address the specific context of the sugar sector in India; simply subsidizing the technology or putting a price on carbon was not enough. Second, where climate (global) and development (local) priorities differ, projects that bring about international goals risk conflicting with more pressing domestic goals.

Chapter 5 - *Concrete Emissions Reductions in Shandong's Cement Sector: Design Options for a Sectoral Crediting Program* – performs a design analysis for a sectoral crediting program in the cement sector in Shandong province in China. The goal of this paper is to explore the possible design of a sectoral crediting program that substantially improves upon the main problems with the CDM. We analyze potential sectoral crediting designs against three criteria: their potential to effectively promote efficiency improvements, ensure that the number of credits generated by the program does not exceed the reductions enabled by it, and meet international standards for reporting and verifying emissions reductions. We offer a typology of sectoral crediting design options being discussed in academic and gray literature and in official post-2012 country submissions and negotiating texts. We then analyze these design options in the specific context of the Shandong cement sector against the evaluation criteria. We find that for most design options sectoral crediting could perform worse than project-based offsetting along the three criteria assessed. Two specific design architectures stand out as having the potential to effectively support verifiable emissions reductions without a high risk of over-crediting those reductions if designed and implemented well.

Chapter 2. Measuring emissions against an alternative future: fundamental flaws in the structure of the Kyoto Protocol's Clean Development Mechanism

1. INTRODUCTION

Industrialized countries have two obligations under international climate change agreements: to meet their emissions reduction obligations, and to support climate change mitigation and adaptation in developing countries. The Kyoto Protocol's Clean Development Mechanism (CDM) has been critical to meeting both obligations. The CDM allows industrialized countries to invest in emissions reduction projects in developing countries and use the resulting emissions reduction credits towards their Kyoto targets. Any project registered under the CDM can produce carbon credits, called certified emissions reductions, or CERs, totaling the estimated tons of CO_2-equivalent emissions avoided by the CDM project. The CDM is the most used of the Kyoto Protocol's "flexibility mechanisms," which are meant to lower compliance costs by allowing industrialized countries to partially meet their emissions targets with reductions made outside of their own borders. The CDM is also the main instrument supporting climate change mitigation in developing countries, facilitating transfer of roughly three billion Euros per year to developers of low-emitting projects in developing countries.[7]

A key challenge of the CDM is to measure the emissions reduced by a single project. Measuring emissions requires comparing the emissions from that project to emissions from a counterfactual scenario of what would likely have happened without the project. This of course involves assumptions about the future. The biggest challenge in determining the counterfactual baseline scenario is assessing whether the project itself is in that counterfactual scenario, or in other words, if the proposed CDM project would have gone ahead anyway, without the expected revenues from the CDM. Any carbon credits generated by projects that would have gone ahead regardless of the carbon credits, allows an industrialized country to emit more than their Kyoto targets without causing emissions to be reduced elsewhere. Each project applying for CDM registration must demonstrate their "additionality," that is that the project would not likely have gone forward had it not been for the expected CDM income. Only projects certified as "additional" are allowed to generate carbon credits under the CDM.

Another key challenge relates to the nature of the CDM credit market. A common appeal of the CDM is that it is a market mechanism meant to create a global market for emissions reductions, lowering the cost of compliance by allowing industrialized countries to reduce emissions wherever in the world it is least expensive to do so while engaging the private sector. In practice, the CDM does not create a market for emissions reductions. It creates a market for emissions permits. It is the permit to emit that is the primary interest of most CER buyers, seeking low cost options of complying with domestic climate regulations. Typically, neither the buyer nor the seller of CDM credits has a strong interest in ensuring the climate benefit represented by the permits. In addition, these permits to emit are wholly human created, numbers in databases, such that no extra cost is incurred from producing more permits. CDM project proponents not only have little incentive to protect the integrity of the permits, they have a financial interest to do the opposite, to exaggerate the number of carbon credits generated by

[7] The CDM projects currently registered under the CDM would produce 380 million tons of CERs a year if they meet the expectations in their PDDs (Fenhann J. 2010. September 1, CDM Pipeline Overview. UNEP Risø Centre, http://www.cdmpipeline.org/). Primary CER prices are currently around 10 Euro per CER.

CDM projects. Therefore, the integrity of this market in terms of emissions reductions relies almost entirely on effective governmental regulation. These features – the buyer is unconcerned with the quality of the underlying physical thing represented by the wholly human-made tradable asset – are also features of many of the financial instruments whose deregulation in the US caused the current global financial crisis, reminding us of the importance of regulation for markets to achieve social ends. As mentioned above, the market in CDM credits is especially difficult to regulate because it requires measuring emissions reductions against a hypothetical scenario, and determining whether the project itself is a part of that scenario.

I examine how the CDM is working in practice in the Indian power sector and how it might be improved. I argue:

- Large numbers of non-additional, business-as-usual projects are registering under the CDM.
- Uncertainty associated with the benefits of the CDM weakens the influence of the CDM on project development decisions.
- Beyond additionality testing, the CDM structure leads to a systematic over-crediting of emissions reductions.
- Even if the additionality of CDM projects could be assured, the large-scale use of offsetting makes long-term international cooperation to mitigate climate change more difficult over the next decades in a number of ways.

In what follows, Section 2 provides background on the state and functioning of the CDM. Section 3 describes the methods supporting this analysis. Section 4 documents how non-additional projects have been able to register under the CDM. Section 5 examines how the effectiveness of the CDM is compromised by the uncertainties associated with its benefits. The next three sections discuss ways that the fundamental structure of the CDM limits its environmental integrity. Section 6 argues that project-by-project additionality testing is inherently inaccurate for projects that reduce carbon dioxide given today's carbon prices. Section 7 presents a number of other ways that the CDM structure systematically leads to the over-generation of credits. Section 8 shows that the large-scale use of offsetting credits undermines long term global cooperation to mitigate climate change over the next decades, even if the quality of those credits could be assured.

2. BACKGROUND

2.1. How the CDM works

Developers of low-carbon projects in developing countries can submit their projects to the CDM Executive Board (EB) for CDM registration. An application for CDM registration includes a Project Design Document (PDD) describing the project, a validation report from an independent third party auditor, and a letter of approval from the host country government. The PDD gives a detailed description of the project, including an estimate of the emissions that it will reduce following the procedures laid out in an approved CDM "methodology," and evidence that the project is additional. A CDM project can involve the building of a new facility, where the baseline is the sector without that new facility; the building of a more efficient facility, where the baseline is a less efficient version of the same new facility; or the upgrading of an existing facility or process, where the baseline is the facility or process without the upgrade. The developer must hire a certified third party auditor, called a validator,[8] to validate that the project meets all of the requirements of the CDM. After a project is approved by the CDM Executive Board, the developer chooses how often to submit requests for the issuance of CERs, which go through a similar process of third party verification and then approval by the CDM Executive Board. Typical end buyers of CERs are governments of and regulated facilities owners in countries that have Kyoto Protocol targets. Often the first buyers of CERs from the developer are intermediary companies that trade in carbon credits. The developer can choose to enter into a CER purchasing agreement with a buyer at any time in the CDM project cycle. They can also choose to sell credits after they are generated. Figure 2.1 presents the key steps in the process of registering a project under the CDM and applying for CER issuance.

2.2. The current state of the CDM

As of August 1, 2010 there were a little over 2,300 registered CDM projects, and another 3,000 proposed CDM projects in the validation process. The total number of registered CDM projects is presented by country in Figure 2.2, and by type in Figure 2.3. China and India host 62% of all registered CDM projects, with few projects registered in Africa and in many other smaller developing countries. 31% of all registered CDM projects are renewable energy projects and 28% are hydropower projects. The high potency greenhouse gases – HFC, PFC and N_2O[9] – make up 4% of all registered CDM projects but are expected to produce 35% of annual CERs, if all projects were to produce the amount of credits predicted in their PDDs (see Figure 2.4).

This paper focuses on CO_2 reduction projects, which compose 73% of all registered CDM projects and 48% of all credits expected from registered CDM projects through 2012. The findings are most relevant to CO_2 reduction projects and some methane reduction projects for which carbon credits are an additional rather than the primary revenue source. Projects that reduce emissions of the extremely potent HFC gas have a high likelihood of being additional since CERs are their sole revenue source. However, the effectiveness of the CDM in reducing these emissions has been questioned on the grounds of efficiency and perverse incentives (see Section 7 for a discussion of this).

2.3. The *Additionality Tool*

The "Tool for the demonstration and assessment of additionality,"[10] is the most common method used for proving the additionality of proposed CDM projects. The *Additionality Tool* requires developers to demonstrate the additionality of their proposed CDM project by an investment analysis, a barrier analysis, or a combination of both.

[8] A validator is also called a Designated Operational Entity, or DOE.
[9] Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs), and Nitrous oxide (N_2O)
[10] The *Tool for the demonstration and assessment of additionality*, and a version of this tool that is combined with a baseline identification methodology - *Combined tool to identify the baseline scenario and demonstrate additionality* - can be found here: http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

Figure 2.1: The CDM Project Pipeline Step-by-Step

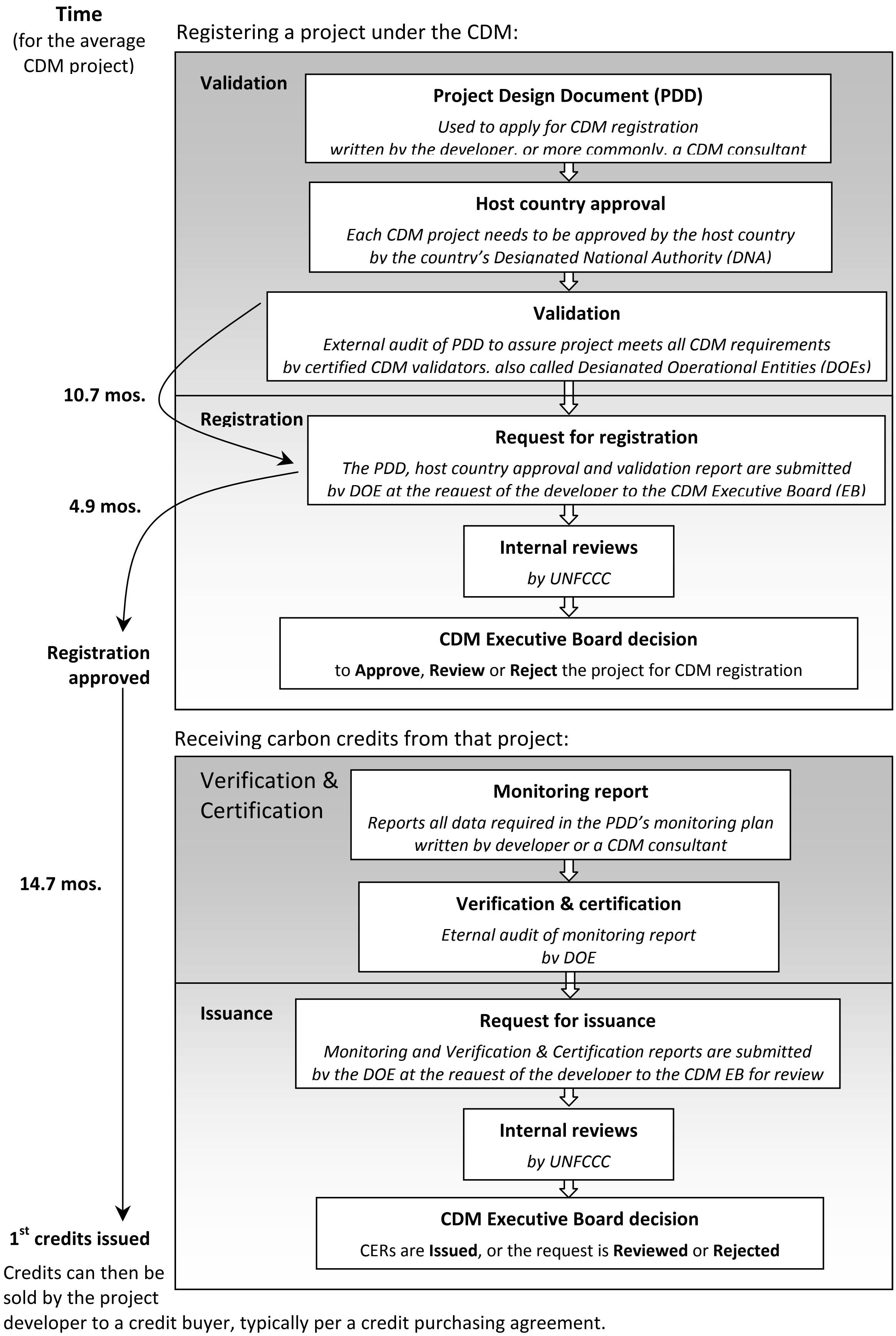


Figure 2.2: Registered CDM projects by host country

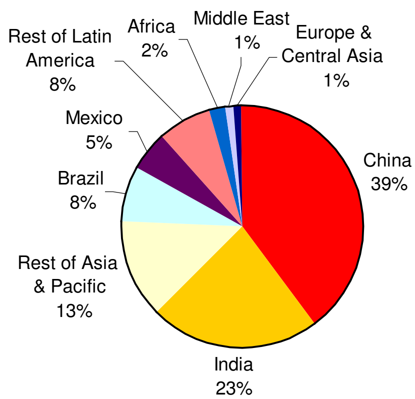


Figure 2.3: Registered CDM projects by type

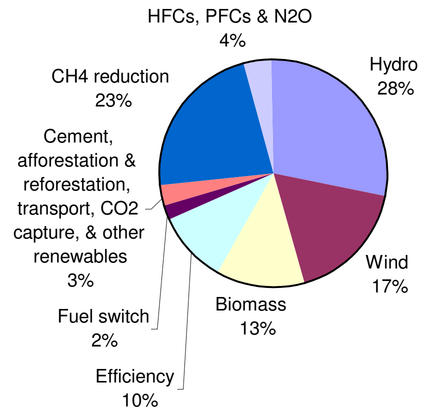


Figure 2.4: Annual expected CER generation from registered CDM projects by type

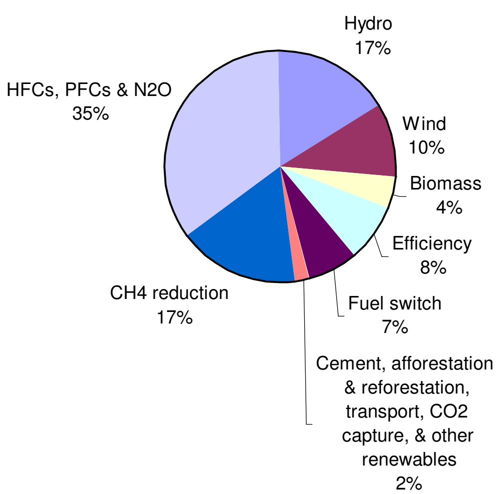
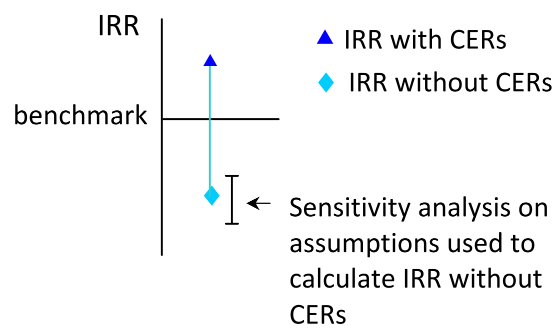


Figure 2.5: The investment analysis



- The investment analysis is used to show that a project is not financially viable without carbon credits. A benchmark is determined that represents the threshold financial return, or hurdle rate, defining whether the project would likely go forward. For renewable energy and hydro projects, the benchmark is most commonly defined in terms of project or equity internal rate of return (IRR).[11] If the expected financial return of the project is below the benchmark, then it is assumed that the project most likely would not have gone forward without carbon credits and the project is considered additional. The financial assessment is tested with a sensitivity analysis of the most important cost and revenue inputs. It is optional to show that CERs bring the financial return of the project above the benchmark. Figure 2.5 illustrates the investment

[11] Internal rate of return (IRR) is the discount rate that would be applied to the cash flow of a project so that the net present value of the project is zero. A higher IRR indicates better financial return.

analysis for a project that is additional and uses IRR as the metric used to assess project financial return.

- The barrier analysis describes and presents evidence for the existence of one or several barriers that prevent the proposed CDM project from going forward without the additional income from carbon credit sales. Examples of barriers are uncertain hydrological flows for a hydropower project and risk of corrosion from the combustion of biomass for a biomass power project.

2.4. Why additionality matters

Additionality is a challenge for any climate mitigation program. Estimation of emissions reduced by policies, programs, and projects is often highly inexact in a complex world in which there are multiple influences on behavior and industrial and consumer choices. International funds that pool contributions to support emissions reduction projects in developing countries, the main alternative to crediting mechanisms, could also end up supporting activities that would have happened anyway. An important difference between crediting mechanisms and funds is that when a fund supports a BAU project, it fails to reduce emissions through that project; when the CDM supports a BAU project, it also weakens an industrialized country target. A second concern is that the complex and technical nature of offsetting programs, and a general, sometimes quite ideological faith in the efficiency of market mechanisms, combine to provide policy-makers with a false confidence of the effectiveness of an offsetting system. To have a high likelihood of limiting global temperature increase to less than two degrees Celsius, substantial efforts are needed in both industrialized and developing countries. Industrialized countries need both to substantially reduce their own emissions and to support mitigation in developing countries. To the extent that CERs are over-credited to CDM projects, the CDM fails in both regards at the same time.

3. NON-ADDITIONAL PROJECTS ARE ABLE TO REGISTER UNDER THE CDM

The poor quality of the barrier and investment analyses used to prove project additionality during 2005 through the first half of 2007 has been well documented (Michaelowa & Purohit 2007, Schneider 2009). Barriers used in the barrier analysis were subjective, not credible, poorly documented, or were so general that they are common to a wide range of CDM and non-CDM projects. Investment analyses left out or did not document important values affecting the feasibility of the projects (ibid.).

Since early 2007, guidelines published by the CDM Executive Board have prevented some poor quality additionality argumentation from passing the additionality test. This section shows that projects have still been able to register during the last three years using dubious additionality arguments. One analysis stands out in the literature. In China, wind developers commonly use 8% IRR as the benchmark needed to make a project viable. This benchmark was introduced by the Chinese government in 2003 and has not been updated to reflect the very different environment of today's Chinese power sector (He & Morse 2010). Further, developers commonly argue that a coal plant would be inappropriate for a benchmark comparison even though coal composes 80% of the Chinese power grid, for the bizarre reason that there are no coal fired power plants as small as the proposed wind projects. If coal were used, additionality would be disproved, since wind projects typically receive higher returns than coal plants in China, because of the promotional tariffs set by the Chinese government (ibid.).

The 80 projects reviewed for this paper provide numerous other examples of questionable additionality arguments. Construction on 16 of the 80 projects reviewed in this analysis began before the Kyoto Protocol entered into force in February 2005 and before the first project was registered under the CDM in November 2004. None of these PDDs mentions a contract with a carbon buyer through which credits will be bought even if the project were not successfully registered as a CDM project. (All of these projects were registered since 2007.) It is highly unlikely that a developer started building a project because of the expectation of generating carbon credits from an offsetting program for which the rules had not yet been decided under a treaty that had not yet come into force.

Seventeen of the 39 Indian projects analyzed for this paper that provide both with- and without-CER IRRs have with-CER IRRs below the benchmark, some by several percentage points. The premise behind the investment analysis is that it should accurately predict whether a project would be built according to the norms of economic and financial rationality and the estimated costs and revenues in the analysis. The investment analysis for these projects predicts that these projects would not be built even with CDM revenues, yet all of these projects were built.

The Xiaogushan hydropower project in China[12] was registered as a CDM project on the basis of having an IRR under the government defined benchmark of 8% for power projects. However, the Asian Development Bank, in its evaluation of the project, describes the project as the least cost project in the entire province, and as being financially viable with an IRR above the 4.53% WACC of the company.[13] The PDD for the Allain Duhangan hydropower project in India uses the company's WACC of 12.6% as the benchmark, while a draft of the project's Environmental & Social Impact Assessment released December 2003 states that: "The project would be one of the cheapest sources of power generation in the Northern Region as compared to alternative of thermal or nuclear power generation."[14] Both of these projects were described by international finance institutions, not only as cost effective, but as the most cost effective in their region. Yet the CDM benchmark analysis was used to "prove" they were unviable.

A murmur of agreement went through the audience at a carbon markets conference in 2007 in Mumbai when a panelist mentioned that board minutes documenting early consideration of the CDM in the decision to build proposed CDM projects are being forged and post-dated. In 2009 one validator proudly told me how he discovered one of these forged documents. One CDM consultant told me that he presented two sets of investment analyses to a bank for a single project – one for the CDM application showing that the project would not be financially viable without carbon credits, and a second for the loan application showing that the project is financially viable on its own.

In India, wind power is often an attractive investment in large part because of the tax benefits offered by the central government. India offers wind power developers the ability to take 80% depreciation for wind project capital costs in the first year of operation along with a 10-year

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[12] I worked out this example together with independent television news producer and journalist Janet Klein.

[13] Asian Development Bank. 2003. *Report and Recommendation of the President to the Board of Directors on a Proposed Loan to the People's Republic of China for the Gansu Clean Energy Development Project*

[14] Himanshu Thakkar from the South Asia Network on Dams, Rivers & People (SANDRP) in New Delhi first alerted me to this quote.
http://www.ifc.org/ifcext/spiwebsite1.nsf/b7a881f3733a2d0785256a550073ff0f/9c7eed7ed0ec2b2e852576ba000e25a0?OpenDocument (Website accessed September 29, 2010; quote is found on page 7 of the report in English.)

tax holiday. Twenty-five large wind projects totaling 1,600 MW of wind power were registered in India under the CDM since 2007. Of these, at least eleven projects incorrectly calculate the tax benefits offered by the Indian government, showing that the projects are less cost effective than they actually were.[15]

At least seven developers and consultants told me that the CDM projects that they proposed would have been built anyway, without the CDM. It was surprising how easy it was to find developers who would say this, given their interest in defending the additionality claims in their CDM application documents. Given the subjectivity involved in project development decisions, possibly the strongest evidence that a project is non-additional is the admission of developers themselves. Many other developers and consultants responded to my probings with general statements that very few CDM projects are additional.

It is a widely held belief among CDM and renewable energy professionals in India is that many CDM projects are non-additional and that the CDM is having little effect on renewable energy development in the country. Interviewees commonly made statements such as: CDM revenues are just "cream on the top"; developers decide to build projects "on their own terms," not based on the small and uncertain change in IRR from carbon credit sales; "any project can be registered under the CDM." While it is very difficult to assess with certainty if a project is additional (the topic of the next section), the poor quality of the additionality arguments used to register CDM projects, evidence of fraud, and the widespread opinion of CDM and renewable energy professionals in India together suggest that many non-additional projects are registering under the CDM.

4. UNCERTAINTY COMPROMISES THE CDM'S INFLUENCE

The proportion of credits from additional projects to non-additional projects is a function both of the non-additional projects able to register, and of the truly additional projects enabled by the program. This section examines how effective the CDM is at enabling new projects to go forward.

The CDM is anticipated to improve the financial return of most of the projects analyzed for this paper by 1% to 7% according to their PDDs. That incentive is weakened by the range of uncertainties associated with CDM revenues throughout the CDM project lifecycle (see Figure 2.1 above for a description of the lifecycle of a CDM project):

<u>Validation risk</u>: Of the 3611 projects that started validation between the beginning of 2007 and the first half of 2009, 600 (17%) were either negatively validated or the validation was terminated by the validators.[16] [17]

<u>Registration risk</u>: Approximately 8% of all projects submitted for registration between the beginning of 2007 and the first half of 2009 were rejected by the CDM Executive Board.[18] [19]

<u>CER issuance/delivery risk</u>: Projects requesting the issuance of CERs on average received 84% of the CERs predicted in their PDDs.[20] [21] In addition, 20% of all projects

[15] Axel Michaelowa first alerted me to this problem. The details of this assessment is described in Section 5.2.1 below

[16] Data taken from UNEP Risoe CDM/JI Pipeline Analysis and Database, September 1st, 2010 http://www.cdmpipeline.org/

[17] For the four project types analyzed in this paper, 16% were negatively validated.

[18] Ibid.

[19] For the four project types analyzed in this paper, 6% were rejected.

registered during 2006 with the expectation of generating credits for reductions starting in 2006 or earlier have not yet had credits issued. Some of these projects might not be able to generate credits because of a failure to follow the plan laid out in the project application documents for monitoring emissions reductions. Uncertainties in CER quantity and price are reflected in CER market valuation. For example, the CER prices offered directly to the project proponents of registered CDM projects (primary CERs) were lower than the price of existing CERs that are being resold (secondary CERs) by 10% to 21% between February to July 2010.[22]

CER price risk: Between January 2007 and July 2010, secondary CER prices fluctuated between a high of 23 Euro in June 2008 to a low of 10 Euro in February 2009.[23]

CER value post-2012: At the time that this paper was written there was still substantial uncertainty about the structure of the post-2012 climate change regime and how CER credits will be used under it.

The behavior of CDM project developers indicates that the financial value of CERs does not provide a go/no-go influence for most projects. Developers are going forward with their projects with the risk that they will receive no benefit from the CDM. Approximately three-quarters of all registered CDM projects worldwide were operational at the time they were successfully registered under the CDM.[24] This means that an even higher proportion had started construction before registration. Further, 76 out of the 80 projects analyzed for this paper started construction before the beginning of the 30-day public comment period, which typically happens

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[20] Ibid.

[21] For the four project types analyzed in this paper, developers received an average of 90% of the CERs expected.

[22] CER prices are taken from Point Carbon's CDM & JI Monitor, which is published every two weeks. The percentages were calculated as the average spread over six months of the difference between the secondary CER price and the high and low primary CER prices reported for registered CDM projects. The low bid price for primary CERs was used for the low primary CER price, and the high offer price was taken as the high primary CER price.

[23] CER prices are taken from Point Carbon's CDM & JI Monitor.

[24] In the UNEP Risoe CDM pipeline database, as of September 1, 2010, 82% of all registered CDM projects have "Credit start" dates equal to, or earlier than, the "Date of registration." The "credit start" date is the date named in the PDD when the developers expect to start generating credits from the project. If a project is expected to be commissioned after the expected date of registration, the credit start date should be named as the expected commissioning date. As of 31 March 2007 projects were no longer allowed to generate credits retroactive to registration (see paragraph 78 of the 28th Meeting Report of the CDM Executive Board). So all projects registered March 2007 that were expected to already be commissioned by the date of registration should have credit start dates equal to the registration date. As of September 1, 2010, only 18% of all registered projects have credit start dates after the date of registration and 24% have credit start dates before the date of registration. What proportion of the 58% of projects with credit start dates equal to the registration date were actually commissioned before the date of registration? Of the 80 project reviewed for this paper, 29 have credit start dates equal to the date of registration. Of these, only two were commissioned after the date of registration, and 25 were commissioned before the date of registration. (The commissioning dates for two of the projects were not found in the CDM project documents or on company and utility Websites.) I also reviewed the PDDs for the large hydro projects registered in China between May 2007 and April 2009. Of the 70 projects reviewed that include the commissioning date in their project documents, 68 were commissioned before the date of registration and only two were commissioned after. In total, only 4% of the 99 projects with registration dates equal to credit start dates reviewed here were commissioned after the date of registration; 96% were commissioned before. Extrapolating this analysis to the whole body of registered CDM projects, this suggests that around three-quarters of all registered projects were completed at the time of registration.

in the first few months of the validation process.[25] This suggests that the large majority of CDM project developers also begin construction before the start of validation, and therefore absorbed both the registration and validation risks. Even though both the validation and registration risks can be avoided by registering a project under the CDM before deciding to go ahead with the project, most project developers do not choose to wait the long, typically over one and a half year, validation and registration process before starting construction.[26] The developers of almost all CDM projects are willing to take the risk that their projects will not be successfully registered.

Multiplying the CER risks together indicates that at the time the decision to build the projects were made, the "rational" value of the CERs expected to be generated by the CDM project was less than half of the value of the funds project developers would actually receive if the projects generate the CER revenues expected:

83% of the projects submitted for validation receive a positive validation	Validation risk
Of those, around 92% are accepted for registration by the CDM Executive Board	Registration risk
The average project that generates credits generates 84% of the credits expected	CER delivery risk
If post-2012 CERs are valued at half of the expected CER price before 2012 because of the large uncertainties associated with the post-2012 climate change regime,[27] the net present value of the CER revenue stream is one quarter lower[28]	Post-2012 risk

The uncertainties associated with CDM benefits for a typical project is calculated as:

$$83\% * 92\% * 84\% * 75\% = 48\%$$

In addition to these risks is the CER price risk.

Project decision-makers, such as the typical lender and some project developers, who are primarily concerned with recovering costs rather than profit earnings, are also more risk-averse and therefore less likely to be influenced by uncertain CDM benefits. Lenders are typically primarily concerned that projects generate the minimum cash flows needed to make loan repayments since they do not benefit from higher profits. This is reflected in the interview

[25] The construction start date was taken from the PDDs. The beginning of the 30-day public comment period is listed in the UNEP Risoe CDM pipeline database as the "comment start" date. Typically the validator puts the PDD up for the public comment period in the first few months of validation.

[26] Using the Risoe CDM pipeline database, the average time between the start of validation and the date of registration for projects registered over the last two years, between September 2008 and September 2010, was 19 months.

[27] Half of the value is a conservative choice for this analysis; the perceived value of post-2012 CERs is probably less than this given the level of uncertainty about the post-2012 regime.

[28] To do this calculation, a discount rate of 13%, the average benchmark for the 80 projects reviewed for this paper, was applied to two CER revenue streams and averaged. Both revenue streams start in 2008; one generates credits for a single ten-year crediting period and the other for three back-to-back seven-year crediting periods (the two options offered CDM project developers.

responses. It is common understanding among CDM practitioners in India that CERs are having little influence on bank lending decisions because of the uncertainties associated with CDM registration and CER generation and value. The two bank representatives with whom I spoke said that CERs have little influence on their decisions to lend to energy projects. Also, project developers whose main motivations are the projects' social and environmental benefits rather than their investment opportunity, such as many non-governmental organizations and community groups, are often primarily concerned with accessing the necessary capital to build the project rather than the potential to earn profits from it. For the most part, CERs do not provide upfront capital, since most carbon credit buyers do not offer upfront payments for future CERs. Those that do pay for CERs upfront offer a heavily discounted price per CER to cover their risk and only very rarely offer upfront payments against post-2012 CERs.[29] CDM transfers have limited benefit to this group of developers.

Many projects have multiple barriers of which low financial return is only one. For example, the development of bagasse cogeneration in India (the cogeneration of electricity and steam from sugar cane waste) required a series of support programs to overcome a range of barriers affecting the dissemination of this cost effective technology. These programs included demonstration projects, information dissemination programs, increased regulatory certainty, easier access to credit, and financial incentives like subsidies and tax breaks. Financial incentives alone were not enough to promote this technology (Haya et al 2009). For many project types, the CDM may work best alongside other complementary support measures, and might not on its own offer the incentives needed to overcome project barriers. More traditional forms of development aid funds, the main alternative to the carbon market, have the versatility of providing many different types of support that can be customized to address the barriers facing different project types in different countries (ibid).

The CDM's uncertainty does not seem to be decreasing over time, and in fact might be increasing. In late 2006, a bank representative expressed his expectation that over time, as banks become more familiar with the CDM, and as more experience is gained with the registration of different types of CDM projects, that his and other banks would start to take carbon credits into account in their loan appraisals. By 2009 the uncertainties associated with the CDM seemed to have increased, rather than decreased. Interviewees in 2009 expressed sometimes bitter frustration with the increased complexity and time involved in the CDM application process, and their perception that the CDM Executive Board is inconsistent and arbitrary in their decisions to reject projects and put projects on hold for extra review.[30] They perceived the Executive Board's efforts to strengthen the system as being hard to work with because the lead to frequent changes in the CDM requirements. Several developers and consultants complained that they could not count on precedence as a predictor of future decisions of the CDM Executive Board. An increase in the number of rejections and extra reviews over the last two years has also increased registration risk.

While previous sections of this paper show that project-by-project additionality testing is currently and potentially relatively ineffective at filtering out non-additional projects, it is one of the key sources of uncertainty in the CDM undermining the value of the CDM to developers to

[29] From interviews with carbon traders and project developers

[30] Also in the Brazilian sugar sector, the efforts made by the CDM Executive Board to strengthen the environmental integrity of the CDM increased the uncertainties associated with the CDM and lessened the influence the CDM had on project development (Pulver S, Hultman N, Guimaraes L. 2010. Carbon market participation by sugar mills in Brazil. *Climate and Development* (2): 248-62).

less than half of the funds actually passed. A high proportion of the risk, time and cost of the CDM application process is associated with additionality testing. PDD consultants and validators describe that a large portion of the time spent writing the PDD and validating the project are devoted to the additionality section. Additionality is the cause of most reviews and rejections by the Executive Board, and is also the most common reason projects do not pass validation.[31]

Lowering the uncertainty associated with additionality testing is much easier than increasing its accuracy. Project-by-project additionality testing can be replaced by clear objective criteria for eligible projects, such as project type, location (e.g. all wind development in sub-Saharan Africa) and level of efficiency (such as the most efficient refrigerators manufactured in Ghana). The challenge in this shift is avoiding allowing even larger numbers of non-additional projects to more easily register under the CDM.

Because project-by-project additionality testing is ineffective, the CDM in essence is a subsidy for the project types allowed under it, albeit, a relatively inefficient subsidy as is argued in this section.

As a result of the uncertainties associated with CDM benefits, the predominant influence the CDM may be having on CO_2 projects is to potentially make cleaner commercial technologies more profitable when developers or investors are willing to accept the risk that they will not receive revenues from carbon credit sales, but value the possibility of doing so.

5. SYSTEMATIC OVER-GENERATION OF CREDITS

Apart from additionality testing, there are two other ways that the CDM's incentive structure leads to the generation of more credits than actual reductions, and can actually increase in emissions.

5.1. Perverse incentives

One of the early criticisms of the CDM is that it could create perverse incentives for a government to refrain from implementing a policy that reduces emissions, or for a business to increase emissions in order to generate more credits from reducing those emissions with a CDM project. HFC destruction from HCFC production facilities provides a good example of both types of perverse incentives. HFCs, a potent greenhouse gas (GHG) regulated under the Kyoto Protocol, is a byproduct in the production of HCFC-22, a temporary substitute for CFCs as a refrigerant. Due to the very high global warming potential of HFCs – 11,700 times that of CO_2 – the value of the CERs generated from HFC reduction projects can exceed the profits from the production of HCFC-22 itself, making HCFC-22 production profitable even if there were no market for HCFC-22 (Wara & Victor 2008). If a country imposes regulation requiring HCFC-22 production facilities to destroy the HFC gas byproduct, facilities should no longer be able to generate the substantial income from the sale of carbon credits, disincentivizing such regulation.

To prevent companies from producing HCFC-22 just to sell CERs generated from the destruction of HFCs, the CDM Executive Board does not allow new or expanded HCFC-22 production to generate CERs. The CDM still disincentivizes companies from decreasing the production of HCFC-22, which could be replaced by a less harmful alternative (Schneider 2007). Also, by not allowing HFC gas from new or expanded facilities to generate CDM credits, while

[31] From interviews with validators

creating perverse incentives against government regulation, the HFC gas is not being destroyed from new HCFC-22 production facilities. The CDM creates a third type of perverse incentive. It has recently been documented that HCFC producers are inefficiently managing their plants to maximize HFC gas, which they can burn for CDM credits, rather than HCFC production.[32] Since HCFC-22 itself is an ozone depletor being phased out under the Montreal Protocol, 5% as potent in depleting the ozone layer as CFCs, the CDM is in direct contradiction with the goals of the Montreal Protocol because of these perverse incentives. Crediting emissions *reductions* rather than taxing emissions improves the profitability of high emitting or harmful projects whenever CERs generate profits rather than simply covering the costs of the abatement technology. Clean coal is another example of a project types for which this can happen.

In the HFC case additionality is relatively straightforward because the only reason to burn the HFC gas is to prevent it from releasing into the atmosphere; there are no other benefits to doing so. For many methane projects, also a potent greenhouse gas, for which CERs would be an additional but not sole reason to implement a CDM project, and for CO2 reduction projects if the CER price were to increase substantially, testing project additionality becomes easier, since the larger influence of CERs on project financial return estimates can overwhelm the effect of the choice of project cost and revenue assumptions. However, in all of these cases, perverse incentives also become more important, as we have seen so clearly in the case of HCFC production.

5.2. The viability paradox

The CDM should result in reductions in emissions in developing countries at least as large as the credits it generates. Each CDM project is allowed to produce carbon credits for its full lifetime, defined either as a single 10-year period or 21 years (3 consecutive 7-year periods) without its additionality being reevaluated. In the power sectors of India, China and elsewhere, hydropower and wind sites are often planned for many years before they are built, and are built in the order of their attractiveness. Let's take for example, a CDM wind project that was built in 2010 because of the CDM, but would have been built in 2014 without the CDM. It is additional at the time it is registered and so is able to generate credits for a full crediting period of 10 or 21 years (depending on which option the developer chooses). By enabling the project to be built four years earlier than it would have, the CDM reduces emissions for only those four years. If that project is able to generate credits for a full crediting period, then it is being over-credited for the remainder of the crediting period when there is no difference between actual emissions, and the emissions in the true baseline scenario, which also includes the CDM project. Supporting projects that would not have otherwise been built for 10 or 21 years would result in a portfolio of relatively unattractive projects, and the odd outcome of enabling substantially less attractive projects, that qualify for the CDM, to be constructed before more attractive projects.[33] In practice, the CDM only tests if a project is additional at the time of the CDM application, leading to the over-crediting of reductions, since many of these projects would have built sometime during their 10 or 21 year crediting lifetimes.

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[32] See http://www.cdm-watch.org/wordpress/wp-content/uploads/2010/06/hfc-23_background-information_gaming-and-abuse-of-cdm3.pdf (accessed July 9, 2010)
[33] This realization came from a conversation with Bill Golove.

6. THE LARGE-SCALE USE OF OFFSETTING CREDITS MAKES CLIMATE CHANGE MITIGATION MORE DIFFICULT OVER THE NEXT DECADES

Even if we manage to design an international offsetting mechanism that effectively reduces emissions and accurately credits them, what effects does large scale offsetting have on global efforts to mitigate climate change over the next decades? Scenarios put forward by the Intergovernmental Panel on Climate Change (IPCC) suggest that a reduction in industrialized countries by 25% to 40% below 1990 levels by 2020, on a path towards 80% to 95% reductions by 2050, still corresponds with a 2.0-2.4 degree Celsius temperature increase (Box 13.7 from Gupta et al 2007, Table SPM.6 from Intergovernmental Panel on Climate Change 2007). These scenarios correspond with reductions in developing countries by 15% to 30% below business-as-usual growth projections by 2020 (Höhne & Ellermann 2008). Even deeper reductions would be needed globally if we wish to have a high likelihood, rather than an almost 50% chance, of not exceeding a two degree increase. Further, since these scenarios were published, additional research suggests that climate sensitivity (the increase in radiative forcing resulting from the increase in GHGs in the atmosphere) is higher, and feedback effects even greater than the assumptions used to produce the IPCC scenarios (McMullen & Jabbour 2009).

Industrialized countries are proposing high levels of offsetting post-2012, which if used, would put these countries far away from the 25%-40% reductions by 2020 from the IPCC scenarios. The EU Climate and Energy Package passed by the EU Parliament in December 2008 included emissions cuts in the EU by 20% below 1990 levels by 2020 outside of an international agreement,[34] allowing 68% of those reductions to be met through international offsets.[35] If all of these offsets are used, the EU would achieve a less than 17% reduction compared to 1990 levels by 2020. In the US, a prominent draft climate bill, the Waxman-Markey American Clean Energy and Security Act of 2009,[36] would require the US to cut it's emissions to 4% below 1990 levels by 2020. This bill allows up to two billion tons of CO_2 as offsets, equal to 28% of its 2005 emissions. Half to three-quarters of these, depending on the availability of domestic offset credits, can be from international sources. The international portion, if used in full, would allow the US to postpone making any reductions in its emissions from 2005 levels until 2020 to 2024. This postponement would be even longer if some portion of domestic offsets is non-additional.

Two justifications are commonly given for high quantities of offsets. The first is simple market efficiency. Trade in emissions reductions allows industrialized countries to reduce emissions less expensively than if they were required to reduce them domestically. Second, by providing low cost compliance options, offsets help bring buy-in from domestic industries, making it easier and more likely for industrialized countries to accept deeper targets than they would have otherwise.

However, large-scale access to these potential lower-cost compliance options also introduces risk to present mitigation efforts and would most likely make climate change mitigation more difficult in the future. First, domestic reductions are more certain than

[34] Those reductions would be increased to 30% in the context of a global agreement containing comparable targets from other industrialized countries and "adequate action" by developing countries.

[35] Hanley N. 2009. *EU Climate and Energy Package, December 2008*. Presented at the Energy and Resources Group, University of California, Berkeley, March 18. The package recommends that 50% of all reductions in the ETS, covering approximately 40% of EU emission, and 80% of reductions in non-ETS sectors can be met with foreign credits.

[36] http://www.govtrack.us/congress/bill.xpd?bill=h111-2454

international offsets.[37] Any country has more knowledge about and control over activities within its own borders than it does for projects and activities which it funds elsewhere. Also, measuring emissions, as is done in a cap-and-trade program, is easier than measuring reductions in an offsetting program, as described in detail above. As such, offsets introduce various uncertainties regarding the amount of emissions reductions they actually represent. Any offsetting in developing countries, whether it is project-based or sector-based, involves measuring emissions against a BAU growth scenario, which is inherently uncertain, and politically difficult to set at a low level.

Second, cap-and-trade weakens incentives for innovation by allowing a larger portion of compliance to be met with existing and low cost technologies (Driesen 2003). Decarbonization to 80-95% below 1990 levels by 2050 in industrialized countries will require major shifts in all high emitting sectors. Transportation, the electricity sector, buildings, and agriculture all involve complex systems. Major shifts in each of these sectors requires time to allow for changes in behavior and in support industries, for experimentation and learning, research, development and deployment, etc.

The high level of offsets allowed could easily place the majority of global reductions up to 2020 in developing rather than industrialized countries. In the context of meeting the global reductions suggested in the IPCC scenarios, if 50% of all Annex 1 reductions are made through offsets (remember that the EU and the US are proposing substantially higher than that as upper limits) and that these offset projects are performed in addition to the suggested 15%-30% decrease from BAU in developing countries, then around 70% of all global reductions through 2020 would likely come from developing countries rather than the high per capita emitters.[38]

If industrialized countries postpone domestic reductions as they are proposing through the use of offsets, they are either committing to steeper annual reductions in the future, or to long-term inequalities in emissions in the North and the South. Both options make future cooperation more difficult. In industrialized countries, a gradual migration of infrastructure is likely to be less costly than rapid transitions that could require retiring technology and infrastructure before the end of their lifetime. If the costs of mitigation are expected to be high, there will be more resistance from industry.

In addition, a high future dependence of offset credits from developing countries poses compliance risks on industrialized countries. The further actual domestic emissions are in an industrialized country from their targets for a given commitment period through the help of offset credits, the harder it will be for that country to commit to meaningful reductions in the following period. Large quantities of offsets might make it easier for industrialized countries to take on deeper commitments now, but could also make it harder for them to accept deeper targets in the future.

We live in a world with a widely shared linear view of development and progress (Norgaard 1994). Deep in urban and rural India, visions of “development” and symbols of high status are heavily influenced by images of consumption from the North. The discourse of development used by the World Bank is also used by country governments, and is disseminated through participants in and those affected by World Bank projects. Developing country citizens have learned that they are “backwards” and “underdeveloped” (Escobar 1995, Gupta 1998).

[37] Here offsets refer to credited emissions reductions generated by any activity whose emissions are not capped under a cap-and-trade program.
[38] Reductions are defined here as reductions from the Kyoto Protocol caps for industrialized countries, and reductions from BAU in developing countries.

Rural electrification has allowed more and more people to view western lifestyles on TV, and TV commercials spreading a culture of consumerism and awareness of not having (Jacobson 2004). Development in India is highly status driven – beyond getting out of poverty is a pursuit of symbols of high status, such as a big car and a new cell phone. In a world dominated by a single vision of "progress" sustainability requires changing the image of what "developed" means. Ultimately, promoting low-carbon development in the South requires demonstrating it in the North.

Advanced developing countries are being asked to join the global community in accepting obligations to mitigation their emissions below BAU growth projections. Will developing countries commit to controlling the growth in their already low per capita emissions if it is clear that there is relatively little willingness in the industrialized world to reduce their much higher per capita emissions? Developing countries will need to make voluntary reductions before it is fair, given how quickly we need to reduce globally. Politically, it will be unlikely that developing countries will take calls for global cooperation seriously, if industrialized countries do not take on commitments to curb their own emissions as prescribed by the IPCC.

Chapter 3. Can the CDM's investment analysis accurately test additionality? A focused look at wind power, biomass energy and hydropower projects in India

1. INTRODUCTION

We saw in the last chapter that additionality testing is failing to prevent large numbers of non-additional projects from registering under the CDM. At the same time it is compromising the ability for the CDM to incentivize the building of new projects by introducing substantial uncertainty into the CDM application process. Two sets of proposals have been put forward for controlling the number of business-as-usual projects registering under the CDM. Some researchers propose improving the rigor of additionality testing requirements used by developers to demonstrate the additionality of each individual proposed CDM project (Michaelowa 2010, Schneider 2009, Wara & Victor 2008). Others propose replacing project-by-project additionality testing with standardized criteria, such as size, type, location and efficiency level, to target categories of projects that are likely additional (American Clean Energy and Security Act 2009, California Air Resources Board 2009, UNFCCC 2010: 41 para 9). Under the latter proposal, any project that meets the criteria would automatically be eligible for CDM registration. In this chapter, I explore the feasibility of the first set of proposals. I examine the possibility of designing an additionality test for individual proposed CDM projects that is reasonably effective at distinguishing additional from non-additional projects. Focusing on wind, biomass and hydropower projects in India, I explore whether there exists a relatively accurate and verifiable indicator of the decisions of investors, lenders and developers to go forward with these projects. In Chapter 5, I examine the potential use of the second set of proposals – standardized criteria.

The appeal of project-by-project additionality testing, used by almost all types of CDM projects as well as most voluntary offsetting programs, is efficiency. Theoretically, the most efficient program would allow the widest range of types of reductions to be credited. Testing the additionality of individual projects, if reasonably accurate, would put the least restrictions on the range of reduction activities that could be credited. Alternatively, standardized criteria rely on the evaluation of categories of projects. This approach would theoretically be more restrictive – only project types on the list are eligible – as well as more lenient with regard to registering non-additional projects – any project which fits the criteria is eligible regardless of whether it is truly additional.

Offsetting programs are only efficient if they are able to be regulated. If regulators cannot have enough information to accurately assess the additionality of individual proposed projects, then the system is only efficient in textbooks.

The CDM's *Additionality Tool*[39] includes two options for demonstrating the additionality of a proposed CDM project – the "barrier analysis" and the "investment analyses." I start with a brief discussion of the barrier analysis (Section 2) and focus this chapter on the investment analysis, considered to have the higher potential for being accurate if made more rigorous (Section 3). Section 4 summarizes and draws conclusions from this study.

[39] The *Tool for the demonstration and assessment of additionality*, and a version of this tool that is combined with a baseline identification methodology - *Combined tool to identify the baseline scenario and demonstrate additionality* - can be found here: http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

2. BARRIER ANALYSIS

The CDM *Additionality Tool's* barrier analysis requires listing barriers, often described in terms of risks, which prevent the proposed CDM project from going forward, but do not prevent an alternative to the project from going forward. For example, barriers common to cost effective energy efficiency include lack of information about or experience with the technology, and the existence of other higher priorities for limited investment capital. The CDM may overcome barriers by improving the expected return from the project activity. Validators are instructed to audit the barriers test by first determining if the barriers are real and supported by sufficient evidence, and then applying their "local and sectoral expertise to judge whether a barrier or set of barriers would prevent the implementation of the proposed CDM project activity."[40] But practically all projects face barriers of some sort. The question is whether it is possible and practical to distinguish barriers with a high likelihood of preventing projects from going forward without carbon credits, from the many barriers that project developers commonly face and overcome doing business-as-usual.

Many of the biomass projects reviewed here (14 out of 19) use a barriers analysis either alone or in combination with an investment analysis to prove additionality. The most common barriers mentioned are: technical uncertainties especially with regard to corrosion in the furnace, that such projects are not "common practice," and uncertainties about the future tariff and the timing of payments considering the bad financial standing of most state electricity utilities. Validators, the auditors responsible for reviewing the application documents of each proposed CDM project, have confirmed the existence of these barriers with reports documenting risks of corrosion from the combustion of biomass, the numbers of biomass projects built in the state compared to fossil fuel projects, and reference to instances of non-payment by state utilities for power produced by renewable energy providers. At best, such evidence can demonstrate that the barriers are real, and that it is feasible that the barriers would have prevented the projects from going forward. The evidence does not demonstrate that the barriers are likely to have prevented the projects from going forward without the CDM. In each case, the developer might have gone forward with the projects without the CDM. In fact, many Indian biomass projects experienced these barriers and did go forward without the CDM.

3. INVESTMENT ANALYSIS

Additionality testing should predict the decision that the developer, lender and investor would make if there were no CDM. The investment analysis presumes that it is possible to accurately predict these decisions from the sign (positive or negative) of a single number – the difference between a benchmark, and the expected financial return from the proposed CDM project, most often defined in terms of internal rate of return (IRR).[41] If the return is below the

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[40] Clean Development Mechanism Validation and Verification Manual, ver 1.1, released December 2009 http://cdm.unfccc.int/Reference/Manuals/accr_man01.pdf

[41] Internal Rate of Return (IRR) - the discount rate that would be applied to the cash flow of a project so that the net present value of the project is zero. A higher IRR indicates better financial return. Net present value is the present value of net project costs and revenues over the project lifetime, taking into account the time-sensitivity of money by applying a discount rate to future costs and revenues.

benchmark, the project is putatively not economically rational and would therefore not be built; if above, the project most likely would be built. It is important to keep in mind that estimating the financial return from a proposed project involves estimating future costs and revenues all of which are predicted with varying degrees of certainty.

The investment analysis is accurate to the extent that developers report the same cost and revenue assumptions and benchmark in their CDM applications as they use in their internal decision-making. Developers have incentives to choose the benchmark and project cost and revenue inputs that show that their proposed CDM projects are additional, so when a range of values is possible, they can choose values strategically. Some investment analysis inputs are distinct values, like the cost of a wind turbine if a supply agreement has already been signed with a wind manufacturer. Other cost inputs have a range of reasonable choices, such as the future prices of biomass fuel.

Figures 3.1 and 3.2 illustrate the accuracy of the investment analysis for two hypothetical sets of projects. Figures 3.1 and 3.2 express project IRRs as a range of values resulting from a range of reasonable cost and revenue assumptions. In Figure 3.1 the projects all have a single benchmark, the choice of input assumptions does not have a large effect on project IRRs, and the effect of CERs on project IRR is larger than the effect of the choices of input assumptions. The first four projects in Figure 3.1 are clearly non-additional – their IRRs are above the benchmark for all possible input values. The last five projects are clearly additional – their IRRs are below the benchmark for all possible input values. The additionality of only the fifth project is unclear. The additionality of the fifth project depends on the actual costs and revenues expected by the developer and how the developer understands and treats risk. If the developer were required by the CDM Executive Board to choose conservative values favorable to the project without the CDM for all project inputs, then it is possible that this project would be ineligible for the CDM even if it were truly additional. In this case, the CDM would miss the opportunity to enable a truly additional project to be built. If, on the other hand, the CDM allows for any reasonable input to be used, then the fifth project could register for the CDM even if it would have been built regardless. Additionality testing is relatively accurate for this set of projects.

Figure 3.2 presents a different set of projects. The range of reasonable cost and revenue inputs can change project IRR by a larger amount. There is also a range of reasonable benchmarks for projects in this sector, and the CDM has a smaller effect on project IRR. In this scenario only the first project is clearly non-additional, and only the last project is clearly additional. All other projects could be additional depending on the project developers' actual cost and revenue expectations as well as the developers' actual hurdle rates, or benchmarks. If the CDM rules require developers to choose conservative assumptions for all cost and revenue inputs and the benchmark, then only one project would be considered additional. It is not clear if this one project would go forward even with the CDM since the effect of the CDM might not be large enough to raise the IRR above the benchmark, depending on the actual cost and revenue expectations of the developer. Alternatively, if the full range of reasonable assumptions may be used in the investment analysis then all but one project could be considered additional, whether or not they actually are. The CDM additionality test is not accurate for the project type represented in Figure 3.2.

Figure 3.1: IRR ranges for 10 hypothetical projects
Varying assumptions within reasonable ranges changes the IRR of each project by <u>less</u> than the effect of CERs

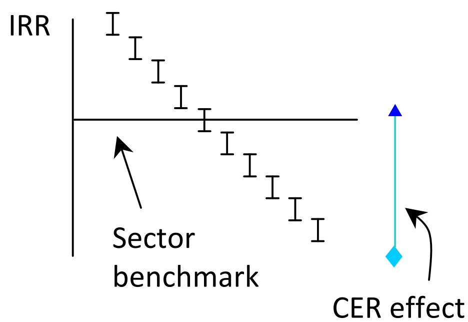
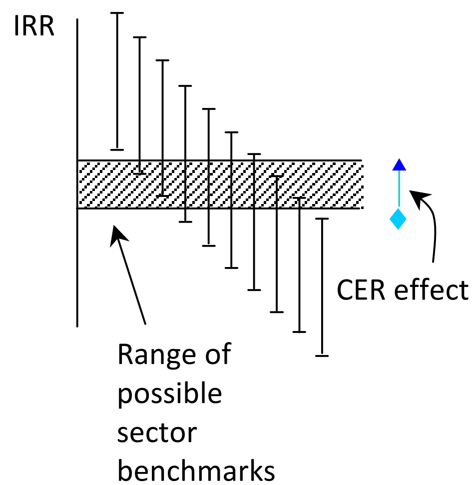


Figure 3.2: IRR ranges for 10 other hypothetical projects
Varying assumptions within reasonable ranges changes the IRR of each project by <u>more</u> than the effect of CERs



These two figures show that the accuracy of the investment analysis is a function of the relative effects on project return of CERs compared to the range of reasonable assumptions that can go into the investment analysis. If the effect of CERs is large compared to the effect of assumption choices (illustrated in Figure 3.1) then there is not much room for developers to game their investment analyses, and the CDM has a strong effect on projects. If the effect of the assumption choices is large in comparison to the CER effect (illustrated in Figure 3.2), then developers have a lot of room to choose assumptions to show that cost effective projects are not cost effective, while the CDM does not do much to support new projects.

The rest of this section examines the extent to which varying assumption inputs within reasonable ranges affect the expected IRRs of wind and biomass projects in India compared to the effect of CERs. This is followed by an examination of the use of the investment analysis for large hydropower projects in India.

3.1. Wind projects: a best case for an accurate investment analysis

Wind in India is a best case for an accurate investment analysis because of the typical organizational arrangement between the project investor and the wind turbine manufacturer. Wind power is often an attractive investment in India because of the tax benefits offered by the central government. India offers wind power developers the ability to take 80% depreciation for wind project capital costs in the first year of operation along with a 10-year tax holiday. A common organizational arrangement for wind development involves an agreement between two sets of actors: a wind turbine manufacturer who identifies and secures a site with good wind resources, and single or multiple investors. The investors are most often profitable businesses and wealthy individuals who are relatively unfamiliar with the energy industry but find wind power an attractive investment in large part because of the depreciation tax benefits. Investors often partially finance the project with a loan. The wind turbine manufacturer typically takes full technical responsibility for the project, and signs a supply agreement with the investors for the sale of the wind turbines and land, plant construction, and operations and maintenance.

A typical result of this arrangement is that all of the main costs of the project to the investor are well documented in three documents: (1) The supply agreement between the wind manufacturer and the project investor documents actual major project costs as agreed between the two parties. It also includes an estimate of the expected generation of electricity that is typically on the high end, which is conservative from the perspective of additionality testing. (2) The tariff for the first ten to twenty years of the project is signed into a power purchasing agreement (PPA) with the utility buying the power. (3) If a loan is taken, the loan interest rate is documented in a loan agreement. Still, three investment analysis inputs are not included in these documents, and involve assumptions that can each have a range of reasonable values that can affect the results of the financial assessment: (1) the per kilowatt-hour (kwh) tariff after the end of the PPA, (2) the tax benefits the developer will receive, and (3) the viability benchmark.

For this best case technology, for which most of the uncertainty in a financial assessment is concentrated in just three values, how accurate is the investment analysis and how validly can additionality be determined? The rest of this section presents the details of a sensitivity analysis I performed on these three values.

3.1.1. Sensitivity analysis on the post-PPA tariff

Electricity tariffs, the prices that power distributors pay power generators per kwh of electricity produced, are determined in India by state electricity regulatory commissions and are published in state-level tariff orders. These tariffs form the basis of legally-binding PPAs between the electricity distributor and generator. State electricity regulatory commissions must balance two competing interests in determining wind power tariffs – supporting the development of renewable energy resources and keeping electricity rates low for electricity customers.

The complete set of twenty-five large wind projects registered under the CDM in India from 2007 to the present are in five states. Fifteen of the wind tariff orders are in Maharashtra and Karnataka. These orders specify 13- and 10-year PPAs respectively and leave uncertain the tariffs after the end of their PPAs. The other ten wind projects are in Gujarat, Rajasthan and Tamil Nadu, where wind tariffs are defined for the full 20-year lifetimes of the projects. Therefore ten projects face little risk about their lifetime tariffs, while the fifteen projects in Maharashtra and Karnataka do face this risk.

Until now, the electricity regulatory commissions in Maharashtra and Karnataka have provided little clarity as to how post-PPA tariffs will be determined. Most state electricity regulatory commissions derive their state-wide wind tariffs on a cost-plus basis for a typical wind project. "Cost-plus" means that the tariff is calculated so that it provides enough revenues to cover all expected project costs plus a specified return on equity (investor profit) each year.[42] It could be reasonable to expect electricity regulatory commissions to rule that post-PPA tariffs will increase to cover inflation. Currently the Maharashtra wind tariff has an escalation rate of 0.15 rupees per year. It is also reasonable for post-PPA tariffs to decrease since project costs are lower after any loans have been paid off. Tariffs calculated on a cost-plus basis for the years after loans are fully repaid would be lower than for the earlier years of the project if the reduced costs were taken into account.

[42] Based on a 70:30 debt-equity ratio.

Karnataka's current tariff order for wind power, published in 2005, defines a tariff of 3.4 rupees per kilowatt-hour for the first ten years of a new project.[43] Regarding the tariff after the end of the first ten years, it states only that the post-PPA tariffs for existing projects will likely be lower than the tariffs for newly commissioned projects for the same year, considering debt will have already been repaid. How much lower is not indicated.

Maharashtra's 2003 wind tariff order divides wind projects into three categories according to their date of commissioning.[44] The tariff for projects commissioned before 1999 follow policies that were in place during the time of their commissioning. These tariffs increase annually throughout the 20-year project lifetime.[45] The tariffs of projects commissioned between 1999 and 2003 increase with an escalation rate for the first eight years of the project; after eight years wind producers are requested to submit tariff petitions to determine the post-PPA tariffs. In June 2010, the post-PPA tariffs for these projects were defined through 2010 as Rp. 2.52.[46] This is around one rupee lower than the tariffs during the eighth year of the PPAs for these projects. The tariff for projects commissioned after 2003 increase with an escalation rate for their first thirteen years. This 2003 tariff order states that wind power should be supported with preferential tariffs, but at the same time customers should not bear an undue price burden, and that the tariff during the first years should be higher than during later years because of the debt burden. At the time these CDM projects were built their post-PPA tariff was still unknown.

Of the fifteen large wind CDM projects in Maharashtra and Karnataka, eight assume that the post-PPA tariff will remain constant following the last year of the PPA. Three in Karnataka assume that the post-PPA tariff will be calculated on a cost-plus basis assuming a 16% return on equity; one project in Karnataka assumes a 10% drop in tariff after the end of the PPA; and two in Maharashtra assume a substantial drop in tariff, applying escalation rates during the subsequent years. One project in Maharashtra did not make their investment analysis spreadsheet publicly available (see Table 3.1 at the end of this chapter).

The post-PPA tariff assumptions for all of these proposed CDM projects are reasonable. On the lower end, it is reasonable to assume that post-PPA wind tariffs will be calculated on a cost-plus basis for a typical wind project after loan repayment is complete. Another entirely feasible assumption is that post-PPA tariffs will remain the same as the final year of the PPA. This is still lower than the tariffs for new projects, but higher than if the tariff were recalculated on a cost-plus basis.

I varied the post-PPA tariffs of the ten large wind projects registered in Karnataka and Maharashtra whose investment spreadsheets have been made publicly available and for which the calculations were straightforward. Varying the post-PPA tariffs between a constant value equal to the tariff in the last year of the PPA, and tariffs calculated on a cost-plus basis changes the IRRs of these projects by 2.4% on average. This is comparable with the 2.7% average expected increase in IRR from CERs for these projects (see Table 3.1 at the end of this chapter). The actual influence of the CDM on the investment decision would be smaller if the

[43] Karnataka Electricity Regulatory Commission tariff order, 18 January 2005, *In the matter of Determination of Tariff in respect of Renewable Sources of Energy*

[44] Maharashtra Electricity Regulatory Commission tariff order, 24 November 2003, *In the matter of Procurement of Wind Energy & Wheeling for Third Party-Sale and/or Self-Use*

[45] They start at 2.25 rupees per kilowatt-hour in 1994, increase at a rate or 5% per year for ten years, are level from year 10 to 13, and then increase at 0.11 rupees per year through year 20.

[46] Maharashtra Electricity Regulatory Commission draft tariff order, 21 June 2010, *In the matter of Determination of Generic Tariff under Regulation 8 of the Maharashtra Electricity Regulatory Commission (Terms and Conditions for Determination of Renewable Energy Tariff) Regulations, 2010*

uncertainties associated with these revenues were factored in to the CER effect, described in Section 4 of the Chapter 2.

3.1.2. Sensitivity analysis on the tax benefits

The Indian government allows wind producers to take 80% depreciation of the capital costs of the project in the first year of operation, as well as a 10-year tax holiday during which time developers pay a reduced tax on project profits. My examination of the investment analysis spreadsheets associated with these 25 projects finds that the owners of at least 11 of the 25 large wind projects registered in India since 2007 incorrectly calculate either the depreciation tax benefits or the 10-year tax holiday offered by the Indian government.[47] These miscalculations result in underestimates of the IRRs for these projects allowing them to more easily pass the additionality test.

The investment analyses for 16 registered Indian wind projects, out of the 25 analyzed here, do not assume that the project owners take the full depreciation tax benefits offered by the Indian government. The investment analyses for these projects calculate the accelerated depreciation benefits as if the projects were independent stand-alone entities functioning off balance sheet for tax purposes, such that the project owners could not use the depreciation benefits to offset their individual or company taxes. Of these 16 projects, the PDDs for only six explain why the project owners would not take the full depreciation tax benefits.[48] Of the remaining ten projects that do not provide explanations, six are made up of a bundle of smaller projects with multiple investors whose main businesses are in a variety of industries. Such an arrangement is typical of investors who use the depreciation benefits to offset taxes in the main part of their business, indicating that these tax benefits were most likely calculated improperly.

Depreciation tax benefits have an especially large influence when equity IRR is used for the investment analysis.[49] Correctly calculating depreciation tax benefits results in IRRs that are 10.2%-19.2% higher than the IRRs included in the PDDs for the six projects that test project additionality with equity IRR, bringing their IRRs far above the named benchmarks. The one project that tests additionality with project IRR would have an IRR that is 3.1% higher if the depreciation benefits were calculated correctly. The depreciation tax benefits affect equity IRR much more than project IRR because the financial benefit from the tax incentives is compared against a smaller capital investment. As a result, another way that developers can affect the results of the investment analysis is to base the analysis on project IRR instead of equity IRR, even if the investment decision were the key decision enabling the project to go forward.

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[47] It is unclear if the depreciation benefits for another four projects are calculated correctly, because the financial structures of the projects are not discussed in the PDDs. An additional four projects do not make their financial spreadsheets available.

[48] Reasons for not being able to avail of the depreciation benefits include: the developer is foreign owned; the developer does not expect to earn enough profits during the early years of the project; and the project is off-balance sheet. “Off

[49] Equity IRR calculates the IRR from the perspective of the equity investor. Outlays include the equity investment, loan repayment, loan interest payments, and all operating costs of the project. Inflows include the revenues from the project. Project IRR calculates the IRR of the whole project. Outlays include the full capital investment, including the loan and equity portions, and all operating costs of the project. Inflows include the revenues from the project. (Note, when a project owner does not take a loan for the project, there is no difference between equity and project IRR.)

Five wind projects incorrectly calculate the benefits from the 10-year tax holiday. This miscalculation results in IRRs that are 1.3%-2.9% lower than they should be, making it that much easier to prove the additionality of these projects.

Miscalculations of the 10-year tax holiday are easy for auditors to catch. Similarly, when it is clear that the investors can use the full depreciation tax benefits, a proficient validator can catch strategic miscalculations. However, in some cases the ability of the investor to use the tax benefits may be unclear. For example, if the investor does not expect to earn enough personal income or company profits to absorb the tax benefits in the first year of the project. This claim may be difficult to audit because it involves assessing an expectation of income in a future year. Also, if a project applies for CDM registration before the owners are fully identified, it will not be known if the project will be on or off balance sheet for each of the owners.

Preventing manipulation of tax benefit estimations is more straightforward than for other types of assumptions like the developer's expectation of their post-PPA tariffs. Government-offered incentives should be assumed to be fully used, leaving the burden of proof on the developer to provide evidence if they are unable to use those benefits.

3.1.3. Sensitivity analysis on the benchmark

According to the latest guidance from the CDM Executive Board on the investment analysis, the developer should choose from among four options for identifying the project IRR or equity IRR benchmark: (1) Local commercial lending rates (for project IRR), (2) weighted average cost of capital (WACC)[50] (for project IRR when there is only one possible project developer), (3) required/expected return on equity (for equity IRR), and (4) benchmarks supplied by relevant national authorities if the validator can validate their applicability (for both project and equity IRR).[51]

Of the 25 large wind projects in India, 16 use equity IRR for the investment analysis. The earlier projects typically use 16% as the benchmark; 16% is the return on equity the Government of India suggests the state electricity boards use to calculate wind tariffs on a cost-plus basis. Following CDM Executive Board guidance in 2008, more recently registered projects calculate the expected return on equity using the Capital Asset Pricing Model (CAPM). CAPM is a commonly used means for estimating the cost of equity capital. CAPM estimates the equity return required by investors from a project as a risk free rate (e.g. government securities), plus a risk premium that takes into account the higher expected IRR needed to counterbalance the risk associated with the particular project type. CAPM uses the following formula based on historical return on equity:

investor expected return = risk free rate + (market rate – risk free rate) * beta

where government securities are typically used for the risk free rate, the market rate is the rate of return from the stock market generally, and beta captures the correlation between the fluctuation of the value of stocks in the specific industry of the project being analyzed and the stock market generally. For example, the milk industry should have a low beta, since purchases remain

[50] Weighted Average Cost of Capital (WACC) is the cost of capital to the project developers, normally combining two components: the costs of a loan (loan interest rates) and the costs of equity (return on equity required by an equity investor).
[51] Executive Board Report 51, Annex 58, *Guidelines on the Assessment of the Investment Analysis (version 3)*, report from EB meeting ending 4 December 2009, http://cdm.unfccc.int/EB/051/eb51_repan58.pdf

relatively steady regardless of the state of the economy, but luxury goods have high betas, since their purchase rates increase and decrease according to the state of the economy. In other words, beta indicates if wind investments are more risky or less risky than the stock market in general.

Several CDM consultants who wrote the PDDs for some of the Indian wind projects analyzed here view the choice of project benchmark as the assumption that is most vulnerable to manipulation in a CDM investment analysis for an Indian wind project.[52] One consultant said that uncertainty in the benchmark practically makes the investment analysis meaningless even for wind projects. Principles of Corporate Finance, a leading textbook on corporate finance, after discussing possible variations to one input into the CAPM model, writes: "Out of this debate only one firm conclusion emerges: Do not trust anyone who claims to *know* what return investors expect." (Brealey & Myers 2003, p. 160)

Table 3.2 presents the benchmarks used for the four most recently registered Indian wind projects that use the CAPM model to determine the benchmark, and the three variables used in the CAPM equations.

The first thing to notice is the relatively wide range of benchmarks – from 14.6% to 18.7% – derived from the CAPM model. This 3.1% range is comparable with the effect of CERs on wind projects, which ranges from 0.8% to 4.9% for the wind projects analyzed in this dissertation. The interest rate on government securities (risk free rate) varies somewhat over time, but is relatively straightforward. However, Table 3.2 shows that project developers are using a wide range of values and data sources for the other two variables based on a number of choices: the date range and the choice of index (BSE 30, 200, or 500) for the expected market return, the individual companies used for the beta calculation, and whether beta is taken as the average for the companies assessed or the minimum beta value of these companies. These are assumptions for which there are no clear preferred choices.

Table 3.2 – Benchmarks and Capital Asset Pricing Model (CAPM) inputs for calculating the expected return on equity for four recently registered wind projects in India

Project #	Construction start date	Benchmark	Risk free rate		Expected market return		Beta	
1291	Aug 2005	**17.8%**	6.11%	Government securities 2004-5	17.25%	BSE* 200 4/1991-7/2005	1.05	Minimum of four large energy companies 2002-5
1168	Mar 2006	**18.7%**	7.34%	Government securities 2005-6	18.83%	BSE 30 4/1979-2/2006	1.34	Average of six large energy companies 2002-5
2925	June 2007	**15.1%**	7.89%	Government securities 2006-7	14.50%	BSE 30 5/1997-5/2007	1.08	Average of eight large energy companies 1997-2007
2605	May 2008	**14.6%**	7.89%	Government securities 2006-7	22.61%	BSE 500 4/1999-3/2007	0.45	Minimum of eight large energy companies 2001-7

* BSE = Bombay Stock Exchange

52 Interviews with CDM consultants conducted in the summer of 2009.

A sensitivity analysis on a single project, project #2605, shows that reasonable assumptions can change the benchmark by over twelve percentage points (the results are very similar for all four projects). The PDD for this CDM project defines the expected market return as the compounded market return from an index of 500 companies on the Bombay Stock Exchange (BSE 500) between April 1999 and March 2007, and calculates the beta as the minimum unlevered beta of eight large energy companies. The following examples demonstrate easy ways to vary the benchmark calculation:

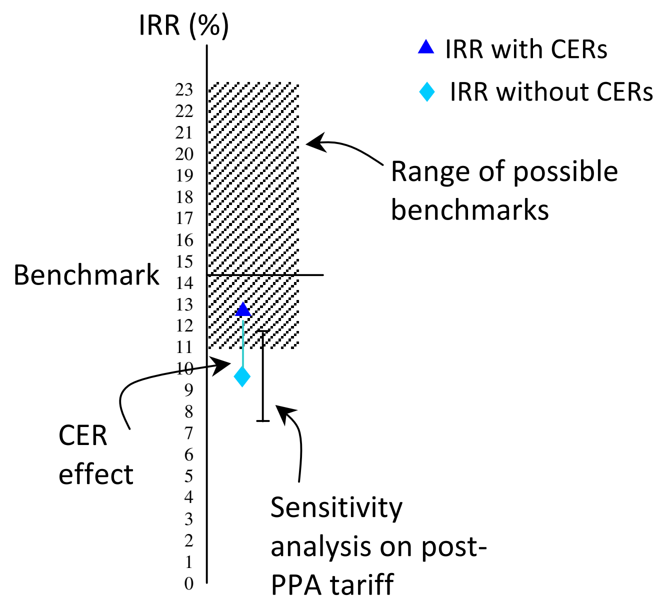
- Using BSE 500 values for ten years and one month, rather than ten years (starting from March 1999 instead of April 1999), lowers the calculated benchmark by 1.08%, from 14.56% to 13.48%. This is as much as the expected effect of CERs on the equity IRRs of some wind projects.
- Using BSE 30 instead of BSE 500 for the same dates lowers the IRR by 3.61%.
- Using the average value instead of the minimum value for the beta increases the benchmark by 4.22%.
- Using the same beta figure as is used by project #2925 increases project IRR by 9.23%.

Varying all of these assumptions simultaneously can change the benchmark by well over 12%, much larger than the effect of CERs.

The main alternative benchmark for wind projects in India, per CDM Executive Board guidance, is the use of local commercial lending rates when project IRR is used. Local commercial lending rates can be too low a benchmark since equity investors generally expect higher return than the lending rate. Combining local commercial lending rates with expected return on equity to cover the equity portion of the capital costs features the same problems as equity IRR described above.

The actual benchmark used in investment decisions can also be influenced by a range of non-monetary factors or factors that are not easily incorporated into the IRR analysis. For example, it is difficult to assess the financial benefits to a company of the reliability offered by a captive generation unit, the political support gained by investing in the project owner's home community, the positive publicity that goes along with doing a green project, or simply the desire to support renewable energy for its climate benefits. Each particular investor has different knowledge of the wind industry and connections in it, which can affect the choice of investment. Further, as the results of the above analysis suggests, investors have varying assessments of wind power as an investment compared with their other investment options.

Figure 3.3: Investment analysis for wind project #2605
with sensitivity analysis on benchmark and post-PPA tariff



The CAPM benchmark used for wind projects in India could apply to any Indian power project, since the companies chosen for the beta calculation are large power producers. The lack of a clear benchmark is a weakness of the investment analysis generally.

3.1.4. Summary of results: The investment analysis as a predictor of wind power development in India

The benchmark is the weakest part of the investment analysis in predicting the building of wind power projects. Small changes in arbitrary factors used to calculate the benchmark return expected by equity investors result in a range of possible benchmarks more than triple the effect of CERs on equity IRR for most projects. In addition, even with this best case technology for which almost all of the cost inputs and revenues are documented in agreements before construction begins, for over half of the projects, the range of reasonable assumptions about the post-PPA tariff can change the IRRs by around the same amount as the effect of CERs. Figure 3.3 illustrates a sensitivity analysis of possible benchmark values and post-PPA tariff on the investment analysis compared to the effect of CERs on one sample wind project. If the depreciation benefits were also unclear, which is an issue in some cases, the range of possible without-CER IRRs would be greater.

For the investment analysis to be accurate even at this level, the supply, loan and PPA agreements would need to be signed before project validation so that the values from them would be included in the investment analysis. Once these agreements are signed, the decision would have already been made to go forward with the project. Developers that wait to make sure their projects are successfully registered under the CDM, or positively validated, before making the decision to build it would be able to use a wider range of assumptions as they construct their investment analyses, since fewer inputs would have been written into contracts by that time.

3.2. Biomass projects: a more typical technology, with a wider choice of assumptions

Developers of biomass cogeneration projects typically manage the projects themselves, rather than contract out project implementation and operations and maintenance through supply agreements as is commonly done for wind projects. Therefore, the IRR analysis for biomass projects includes many more assumptions for which the expectations of the developer are not clearly documented and for which there may be a range of reasonable values.

For example, for projects that purchase all or part of the biomass used for electricity generation from near-by farms (7 of the 19 large biomass CDM projects in India), assumptions must be made about future biomass prices. Biomass prices have been erratic in the recent past due to an absence of a developed supply market (Ghosh et al 2006), rainfall variability year-to-year[53] and rising demand for biomass from pulp and paper mills and for electricity generation.[54]

Focusing on just this one cost assumption, I examine the effect of the projected future price of biomass on the project IRRs of the four biomass projects in India that purchase biomass fuel from outside their facilities and make their investment analysis spreadsheets publicly available .[55] These four projects use rice husk purchased on the market to supplement the

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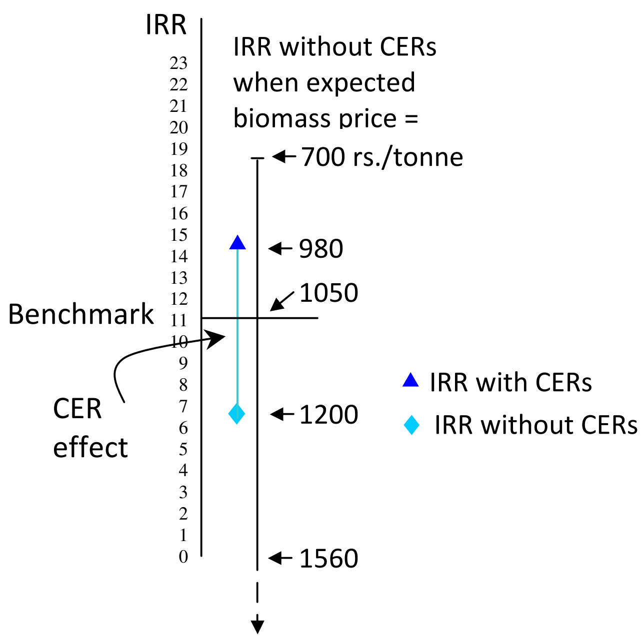
[53] Raised in a number of interviews with developers and consultants of bagasse (sugar cane waste) cogeneration projects.
[54] ibid.
[55] The idea for doing an analysis on biomass prices comes from Sivan Kartha from the Stockholm Environment Institute.

Figure 3.4: Investment analysis for biomass project #2708
with sensitivity analysis on future expected biomass prices



biomass generated by each facility's own rice or sugar processing, and all are in Uttar Pradesh (UP), the Indian state with the most large biomass CDM projects.

The investment analyses of these four projects forecast future rice husk prices that vary by a factor of four (2650, 1200, 1150 and 700 rupees per metric ton) with varying annual escalation rates (0%, 4%, 2% and 0% respectively) (see Table 3.3 at end of chapter). These projects all started construction within a year and a half of one another, and the assumptions used in the investment analysis should reflect expectations at the time the decisions were made to build the projects. The timing of the project development decision does not explain the large variation in their assumptions about future rice husk prices.

All values within this wide range of price assumptions and escalation rates are reasonable assumptions, since the full range is reflected in the range of biomass prices assumed in UP and central government tariff orders. The UP tariff for biomass from 2005 was based on a price of 740 rupees per tonne of biomass fuel.[56] Three years later a UP tariff order for biomass mentions sugarcane waste (bagasse) fuel prices of 2250-2500 rupees/MT during the off-season.[57] The Central Electricity Regulatory Commission tariff order for renewable energy sources of 2009 forecasts biomass prices in UP to be 1518 rupees/MT during 2009-10 and assumes a 5% annual escalation rate in biomass prices.[58] It is difficult to predict future biomass prices because the market for biomass is new, undeveloped, and growing, and because availability of biomass is dependent on rainfall.

The choice of just this one variable puts into question the validity of the investment analysis for biomass projects that purchase biomass fuel (See Table 3.3). Figure 3.4 illustrates a sensitivity analysis of the choice of biomass price for one biomass project. A decrease in biomass price of just 220 rs./tonne, from 1200 to 980 at the beginning of the project, increases the IRR by an amount equivalent to the effect of CERs on IRR. Similarly, keeping the biomass price at 1200 at the start of the project, and lowering the expected annual escalation rate in biomass prices

[56] Mentioned in the updated draft tariff order: Draft "Uttar Pradesh Electricity Regulatory Commission (Terms and Conditions of supply of power from Captive and Non-conventional Energy Generating Plants) Regulations, 09" (CNCE Regulations'09). http://www.uperc.org/UPERC%20CNCE%20Order%20%20_Final.pdf

[57] Suo-moto proceeding on procurement of power through competitive bidding and alternative fuel for use of bagasse based co-generation capacity during off-season. 1 May 2008. http://www.uperc.org/Order%20for%20CNCE%20Regulation%202008%20-%201st%20May%202008.pdf

[58] Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2009, http://www.cercind.gov.in/Regulations/CERC_RE-Tariff-Regualtions_17_sept_09.pdf

from 4% to 1.6% changes the IRR by the same amount as CERs. Both of these changes are small compared to the range of assumptions for the four projects analyzed.

Biomass price is only one of many assumptions that can be varied by a developer who wishes to show a lower project IRR in their PDD. Operations and maintenance is another cost that is fairly uncertain for biomass projects. Also, as with wind projects, the actual benchmark is difficult to predict, especially since it is difficult to place a value on the reliability that captive power offers, and often investment in biomass cogeneration is weighed against other potential investments into a factory that are plant specific.

3.3. Hydropower projects: inappropriate for an investment analysis

Additionality testing is inappropriate for large hydropower in India for two reasons: the development of hydropower is a government decision, and large hydropower developers are guaranteed a specified return on their equity investment making an IRR analysis meaningless.

3.3.1. Hydropower development is largely a government decision

The Government of India employs a central decision-making process to determine the development of its rivers, in recognition of rivers as a national resource with multiple competing uses – electricity, irrigation, flood control. River development is determined through a government planning process involving a range of public and private actors. This planning process identifies potential hydropower sites and determines which specific sites will be developed in what order and by which sector – central, state or private. The private sector participates in hydropower development mainly by responding to bids put out by state and central state-owned companies. Additionality testing is not meant to predict the decision-making processes of governments which typically involves a multiple and complex set of considerations extending beyond cost effectiveness.

3.3.2. Developers of large hydropower projects in India are guaranteed a certain return on their equity investment

Developers of large hydropower projects (defined in India as over 25 MW) are guaranteed a pre-determined return on their equity investment, typically 14% or 15.5%.[59] The tariff the developer receives per kwh from electricity sales is calculated on a cost-plus basis for each hydropower facility and adjusted periodically to ensure that the developer receives the agreed return on equity based on their true costs and revenues. This means that most project costs are "passed through," since they are returned to the developer through the tariff. Therefore hydropower developers do not take the risk that there will be cost overruns during construction, or that less power will be produced than expected.

Project IRR does vary slightly among large hydropower projects in India, because the costs that determine the tariff differ somewhat from the costs included in a typical CDM project IRR analysis. But these differences do not capture the main factors that determine the order in which hydropower sites are built and if private developers are interested in putting forward bids. First, to incentivize efficient plant operation, operations and maintenance (O&M) costs are calculated as 2% of capital costs annually with an annual escalation rate in the tariff calculation,

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[59] 14% is the return on equity from the Central Electricity Commission's 2005 tariff order and 15.5% is the return on equity from the 2009 tariff order. The CERC order applies to all central plants, and plants whose electricity is traded between more than one state. Each state writes its own tariff policy for its own plants, typically modeled after the CERC policy.

regardless of the actual costs.[60] In contrast, the IRR analysis uses the actual expected O&M costs, calculating lower IRRs for projects with higher ratios of O&M to capital costs. Second, capital costs are not always fully passed-through, depending on a reasonability check by the appropriate electricity regulatory commission. Projects that are judged by regulators to be built or managed inefficiently will have lower IRRs since the full capital costs are not passed through.[61] Third, projects with longer construction times, which typically is the case with larger projects, projects built under more difficult geological conditions, or projects against which there is substantial public protest, will have lower IRRs. This is due to the way IRR takes into account time – give greater weight to costs and revenues in the early years than the later years. For one cost variable the IRR analysis actually points in the wrong direction. Counter-intuitively those projects that are able to attract *better* loan terms will calculate *lower* IRRs, since loan interest payments are passed through in the tariff calculation, but are not included in project IRR calculations. Perhaps the only significant indicator of project viability that is reflected in the calculated IRR is the longer expected construction time. When the tariff is determined on a cost-plus basis per project, an IRR analysis is not an appropriate indicator of whether a project would be built.

4. DISCUSSION AND CONCLUSIONS

I show that the accuracy of the investment analysis is a function of the relative effects on project return of CERs compared to the range of reasonable assumptions that can be used in the investment analysis. If the effect of assumption choices is small compared to the effect of CERs then there is not much room for developers to game their investment analyses. If the effect of the assumption choices is large in comparison to the CER effect then developers have room to choose assumptions to show that cost effective projects are not cost effective.

Even the best case for an investment analysis – wind projects in India – in which all of the main inputs into the financial assessment are documented, there is still some room to vary cost and revenue assumptions within ranges equivalent to the effect of the CERs in some cases. For most other project types there is much more room to manipulate cost and revenue inputs. The choice of the biomass price for biomass projects in India is one example. Even if cost and revenue figures were assumption-free, the viability benchmarks against which project IRR is judged are themselves sensitive to assumptions. The sensitivity of risk assessments to small changes in benchmark calculation parameters seem to preclude a benchmark for most projects that is meaningful within the relatively small improvements carbon credit revenues have on the IRR of CO_2 reduction projects. Both the IRR analysis and the benchmark IRR are adjustable in tandem.

A look at Indian hydropower suggests that it is important to look at the specific conditions under which technologies are developed to determine if the investment analysis and additionality testing more general is appropriate for that specific technology. Large hydropower in India is inappropriate for additionality testing because decisions to build large hydropower sites are made by the government rather than the private sector based on multiple considerations,

[60] For projects commissioned after April 2004.

[61] Interviews with hydropower consultants indicate that private hydropower developers that experience costs overruns are typically able to pass through the full actual costs through a higher tariff. Public companies can find it more difficult to get cost overruns passed through in full.

and hydropower tariffs are determined so that developers receive a specified return on their equity investment rendering the IRR analysis meaningless in most cases.

The claim that additionality testing is manipulatable corroborates the views of the validators interviewed. Four validators from four of the five largest validation companies in India, tasked with auditing CDM additionality claims, hold the view that current additionality testing procedures are subjective and can be manipulated. One validator described the many "knobs you can turn" to change the results of the financial analysis. Several validators suggested ways to lessen the manipulation, but did not believe that it is possible to prevent it. This view is held by many more CDM experts as well.

In conclusion, an accurate project-by-project additionality test is impractical for CO_2 reduction projects. Another means for determining which projects are worthy of receiving international support through international climate change agreements is required.

Table 3.1 – Sensitivity analysis on choice of post-PPA tariff on wind project financial return

Project #	State in India	Construction start date	PPA length (years)	Tariff in year 1 (rp/kwh)	Tariff escalation rate	Tariff after end of PPA (rp/kwh)	Based on?	IRR when post-PPA tariff calculated on cost-plus basis	IRR when post-PPA tariff is same as last year of PPA period	Sensitivity of IRR to post-PPA tariff (difference between previous 2 columns)	Effect on IRR from CERs
1687	Karnataka	14-Dec-07	10	3.4	--	3.4	same as PPA	7.82%	9.34%	1.52%	4.00%
1949	Karnataka	27-Apr-07	10	3.4	--	3.4	same as PPA	9.88%	11.93%	2.05%	1.72%
1824	Karnataka	15-Jan-07	10	3.4	--	3.4	same as PPA				
1268	Karnataka	1-Jan-07	10	3.4	--	1.6-3.0 (varies)	cost-plus	9.45%	11.36%	1.91%	1.68%
2265	Karnataka	23-Jun-06	10	3.4	--	3.06	lower without justification	10.38%	13.62%	3.24%	4.94%
1259	Karnataka	10-Mar-06	10	3.4	--	1.5-3.1 (varies)	cost-plus	8.68%	10.84%	2.16%	1.43%
1291	Karnataka	1-Aug-05	10	3.4	--	1.5-3.1 (varies)	cost-plus				
998	Karnataka	2001-5	10 (assumed)	3.1	--	3.1	same as PPA	12.40%	15.40%	3.00%	2.30%

Project #	State in India	Construction start date	PPA length (years)	Tariff in year 1 (rp/kwh)	Tariff escalation rate	Tariff after end of PPA (rp/kwh)	Based on?	IRR when post-PPA tariff calculated on cost-plus basis	IRR when post-PPA tariff is same as last year of PPA period	Sensitivity of IRR to post-PPA tariff (difference between previous 2 columns)	Effect on IRR from CERs
2605	Maharashtra	8-May-08	13	3.5	0.15	3.5 with escalation rate	without justification	7.30%	11.80%	4.50%	3.00%
2092	Maharashtra	9-Feb-07	13	3.5	0.15	5.3	same as last yr of PPA	6.46%	8.42%	1.96%	2.18%
1615	Maharashtra	1-Jan-07	13	3.5	0.15	5.3	same as last yr of PPA	11.19%	12.56%	1.37%	??
1600	Maharashtra	28-Dec-06	13	3.5	0.15	3.89 with escalation rate	without justification				
1115	Maharashtra	27-Jun-05	13	3.5	0.15	5.3	same as last yr of PPA	12.23%	14.28%	2.05%	2.77%
967	Maharashtra	2005	8	2.91	0.11	3.68					
744	Maharashtra	2005	8					Spreadsheet not available			

Values are left blank for projects for which the calculations are not straightforward, such as for projects funded 100% by equity, and projects with spreadsheets containing circular references.

Table 3.3 – Effects of future biomass price on biomass project financial return

Project name	PDD Date	Start project construction	Rice husk price in first year rs./ton	Rice husk price annual escalation rate	Change in IRR or DSCR* from CERs	Decrease in rice husk price needed to increase return same amount as CERs	Decrease in escalation rate needed to increase return same amount as CERs
Rice husk based Co generation project at Dujana unit of KRBL Limited	Jan-08	Oct-05	2650	0%	0.45	380	
15 MW Biomass Residue Based Power Project at Ghazipur	Nov-08	Dec-06	1200	4%	7.86%	220	2.4%
DSCL Sugar Ajbapur Cogeneration Project Phase II	Feb-07	May-05	1150	2%	7.11%	430	
KM RE project	Jan-07	Feb-06	700	0%	8.07%	490	

[a] DSCR (Debt Service Coverage Ratio) is a common financial metric used by banks to assess loan applications. A DSCR of less than one means that annual project revenues are less than the annual debt service. Here, the first project uses DSCR to measure project viability, and the other three use project IRR.

Chapter 4: Barriers to sugar mill cogeneration in India: insights into the structure of post-2012 climate financing instruments

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1. INTRODUCTION

In this chapter we offer an in-depth look at the history of the development of high efficiency bagasse cogeneration (the generation of electricity and steam from sugar cane waste) in India. The story of the bagasse cogeneration, played out in a complex development context interlinked with multiple sectors of the Indian economy, offers a rich case study for exploring the barriers to a technology, opportunities for supporting a technology, and how the incentives created by the CDM match those barriers and opportunities as they change over time and vary among states and facility types. We compare the effects of the CDM with the range of other programs supporting the development of this technology. We describe the development of bagasse cogeneration in India from its early projects through its capacity by the end of 2007, at 711 MW, 14% of its potential, examining why this cost effective technology has not achieved greater deployment.

Efficient bagasse cogeneration in India has been ranked among the highest for its potential for cost-effective emissions reductions and other development and environmental benefits (Banerjee 2006, Smouse et al 1998). India's sugar industry competes with Brazil for being the largest in the world and has the potential of contributing 5000 MW to the country's electricity grid (Ministry of New and Renewable Energy 2008, Natu 2005), which currently stands at a total capacity of 145,600 MW (Ministry of Power 2008). More recent estimates have been slightly higher, indicating a potential of 5575 MW (Purohit & Michaelowa 2007). The technology improves the profitability of the sugar sector, which employs approximately 500,000 people (Natu & Zade 2002), and on which 50 million sugarcane farmers depend (Department of Food & Public Distribution 2003). We examine how it came to be that only 14% of India's estimated potential for bagasse cogeneration has actually been exploited to date, despite its cost effectiveness, multiple purported benefits, and numerous domestic and international programs to designed to support the technology. This study focuses on bagasse cogeneration development in Maharashtra and Tamil Nadu, two of the largest sugar producing states in India. In Maharashtra, sugar is predominantly owned by sugar cooperatives, whereas in Tamil Nadu the sugar sector is largely private. These divergent trends in agrarian development have important implications for the capacity of these two states to exploit their bagasse cogeneration potential.

The following section of this paper provides background information on India's energy and sugar sectors, bagasse cogeneration development in the country, and previous government and international programs supporting the technology. We then describe our research design and study sites in Maharashtra and Tamil Nadu. This is followed by a detailed analysis of the barriers that have faced bagasse cogeneration over the last decade in both the private and cooperative sectors, and the effects of support programs in overcoming them. The following discussion examines the implication of these findings on the structure of financial instruments under the post-2012 climate regime.

2. BACKGROUND

2.1. India's energy sector

The potential benefits of increasing the implementation of bagasse cogeneration can be understood in the context of India's rapidly growing, predominantly coal-based power supply. The combined impacts of urbanization, population growth, and economic liberalization in the 1990s increased electricity consumption by five times from 1980 to 2003 (Energy Information Administration 2007). There continues to be a considerable demand-supply gap as well as poor quality of supply (low voltage and grid instability) and substantial transmission and distribution losses and theft are estimated to be greater than 40% of power generation (Planning Commission of the Government of India 2006). In order to bridge the supply-demand gap and to keep pace with its rapid growth in GDP, India plans a rapid expansion of its power sector infrastructure. The government targeted an increase of 100,000 MW between 2002 and 2012 constituting a doubling in capacity (Ministry of Power 2005) of which 10% is to come from renewable resources. Between 2002 and 2008 India has achieved an increase in capacity of approximately 40,000 MW (Ministry of Power 2008, Planning Commission of the Government of India 2002), 20% of which is from renewable energy.[62] In 2005, 69% of India's electricity was generated from coal (International Energy Agency 2005).

In order to increase the diversity of its energy portfolio, India has made efforts to increase its renewable power capacity. Total grid-connected renewable energy capacity[63] stands at around 12,200 MW (Ministry of Power 2008), of which wind and small hydro dominate (Ministry of New and Renewable Energy 2008). This figure, however, is only a small proportion of India's total resource potential in renewable energy. Overseeing the various policy incentives for renewable energy is the Ministry for New and Renewable Energy (MNRE, and until recently called the Ministry for Non-Conventional Energy Sources or MNES). Its activities include, among other things, coordinating demonstration programs, collecting and compiling resource data, and offering various tax, custom duty and capital and interest subsidy benefits (MNES 2004).

India's power sector is severely financially constrained. Most state electricity boards (SEBs) are functioning at substantial losses, and have experienced a spiraling decline in their financial standing and the quality of electricity they provide. Since the 1970s, high industrial tariffs have cross-subsidized low tariffs paid by residential customers and in the agriculture sector and helped cover large transmission losses. Over time, industrial customers started to install dedicated generators which they found to be more reliable and cost effective than grid electricity with its frequency fluctuations and brown and blackouts. As these customers left the grid, utilities saw their revenues base diminishing. This weakened the financial stability of the utilities, including their ability to build more capacity to keep up with increasing demand, which further compromised the quality of the power they produced. With the resulting decline in the reliability of the grid and electricity quality, industrial facilities continued to build captive plants

[62] Figures taken from Ministry of New and Renewable Energy Annual Reports
[63] Including small hydropower plants, defined as hydropower plants below 25 MW

to replace grid electricity and continuing customers became more resistant to tariff increases (Dubash & Rajan 2002).

A number of reforms in the power sector have been underway since the late 1990s to tackle these inefficiencies with mixed results to date. In 2003, in an attempt to formalize various state-led initiatives, the central government passed the Electricity Act 2003, replacing all previous legislation in the sector. This electricity reform process involves the vertical debundling of generation, distribution and transmission, the establishment of independent electricity regulatory commissions in every state, and the implementation of competitive bidding for electricity contracts. .

2.2. Sugar sector and cogeneration technology

India's sugar sector competes with Brazil's as the largest in the world, and is the second largest agriculture-based industry in India behind textiles (Natu & Zade 2002). A majority of its production is destined for domestic markets (FAO 2003 in WADE 2004). India has over 500 sugar mills, 95% of which are located in nine states (Uttar Pradesh, Bihar, Punjab and Haryana in the north, Maharashtra and Gujarat in the west, and Andhra Pradesh, Tamil Nadu and Karnataka in the south). India's sugar sector is very heterogeneous. Mill size ranges from 500-10,000 tonnes crushed per day (TCD), with an average capacity of 3,300 TCD (Tuteja Committee 2004). However, small mills with a capacity of less than 2,500 TCD are considered less efficient and less economically viable than larger mills. Recognizing this, the central government issued a mandate that only factories of above 2,500 TCD would receive new licenses. The government also provided additional incentives for mills that undertook expansion projects (i.e. for those mills that wanted to expand from 1,250 TCD to 2,500 TCD and beyond). However, many mils established between 1950-1980 are smaller in size and use outdated technology.

Approximately 60% of India's sugar sector is owned and run by farmers through cooperatives, a situation that is unique to the country, while private sugar mills in India are the second largest producer. As with other agricultural cooperatives in the developed and developing world, in the sugar cooperative system in India individual landowning farmers are also shareholders in the sugar factory. Between 10,000-50,000 farmers belong to a single cooperative. Farmers deliver cane to the factory during the crushing season, and theoretically have a say in the functioning of the cooperative as well through their vote. Revenue earned from sugar sales are redistributed to farmer-members in the form of a sugarcane price (Ranganathan 2005). The cooperative system generally suffers from poorer coordination and is therefore less efficient that the plantation system most common in other sugar-producing countries like Brazil. This is because the timing for harvesting and crushing sugarcane is crucial, and should be done when the sucrose content in the cane is at peak maturity. There therefore must be coordination among many small sugar farmers and the sugar mill so that sugar is harvested at its peak, while there is a steady and adequate supply of raw material to the factory (Attwood 1992). Given its lesser efficiency, the reasons why the cooperative system is still dominant in sugar production in India are rooted in colonial history. Unlike colonial expansion in the New World, British policy did not involve expropriating large amounts of land from the Indian peasantry to cultivate sugar (ibid.).

As a means of meeting their factory needs for electricity and steam, and of disposing of the large quantities of bagasse (fibrous waste) left over after processing sugarcane sugar mills all around the world burn bagasse in boilers to produce both steam and power. In the 1960s efficient bagasse cogeneration was pioneered in Mauritius and Hawaii. The implementation of higher pressure (60 bar and higher) and higher temperature (450 degrees C and higher) boilers, and corresponding turbines allowed the more efficient burning of bagasse with export of electricity to the grid. Today, a minority of mills around the world export surplus power to the grid via more efficient, high temperature, high-pressure boilers. For instance, Mauritius, an island country with very little fossil fuel reserves, meets 8% of its electricity demand through sugarcane waste alone (Deepchand 2001).

In order to maximize the use of steam for electricity generation, steam-drives are replaced with electrical drives, ensuring more power from the same amount of bagasse. Bagasse cogeneration also creates incentives for increased mill efficiency to maximize the electricity available for export to the grid. Since most cooperative mills have outdated inefficient technology, a considerable amount of investment must be made.[64] Even though both the low efficiency and high efficiency cogeneration of bagasse can technically be considered bagasse cogeneration, in this paper the term "bagasse cogeneration" refers to the high efficiency technology.

The sugar industry is well-suited for cogeneration for several reasons: (i) the continuous manufacturing process of sugar (as opposed to a batch process) is useful for continuous electricity generation, (ii) sugar processing requires only low-pressure steam, making higher pressure steam available for electricity generation, and (iii) decentralized sources of electricity supply reduce efficiency losses on state grids. Bagasse cogeneration produces net zero emission of carbon dioxide, since the carbon released as CO_2 when bagasse is combusted, was taken out of the atmosphere through photosynthesis.

2.3. Support for bagasse cogeneration in India

In India, interest in high efficiency bagasse cogeneration started in the 1980s when the supply of electricity started falling short of demand. Since high efficiency bagasse cogeneration has been perceived as an attractive technology both in terms of its potential to produce carbon-neutral electricity as well as its economic benefits to the sugar sector, a number of domestic and international programs were launched to support the dissemination of this technology, the largest of which are listed in Table 4.1 and described below.

Table 4.1. Largest programs that have supported bagasse cogeneration in India

Funding institution	Type of support provided
Ministry of Non-Conventional Energy Sources (MNES)	Interest subsidy, capital subsidy, tax benefits, workshops, pilot projects in the cooperative sector, and lower customs duty for importing technologies
USAID	Up to 10% equity contribution for 9 demonstration projects, trainings, workshops, newsletter, and outreach activities
Indian Renewable Energy Development Agency (IREDA)	Multilateral lines of credit for renewable energy development provided through IREDA from international and bilateral finance institutions. The Asian Development Bank (ADB) provided funds dedicated for bagasse cogeneration.

[64] Interview with sugar engineer, July 2004

Clean Development Mechanism (CDM)	A project-based carbon offsetting program established under the Kyoto Protocol
Global Environmental Facility (GEF)	Project under preparation to provide creative financing to cooperative mills

Ministry of Non-Conventional Energy Sources (MNES)
The national program on Promotion of Biomass Power/Bagasse Based Cogeneration was launched in 1992. It involved demonstration projects specifically in the cooperative/state sugar sector, as well as biomass resource assessment studies, training, and assistance to states in formulating their power purchase policies. In 1994, MNES expanded its bagasse program by offering capital and interest subsidies, research and development support, accelerated depreciation of equipment (e.g. boilers, turbines, waste heat recovery systems), a five-year income tax holiday, and excise and sales tax exemptions. Capital subsidy for cogeneration projects in the cooperative/public sector sugar mills were Rs. 3.5-4.5 million/MW ($0.87-1.1 million/MW) depending on the level of pressure of the boiler. Interest subsidies for commercial biomass power projects were 1-3% depending on the pressure of the boiler. MNES also offered a range of other services, such as biomass resource assessments, and funding for bagasse cogeneration workshops and prefeasibility studies. Jawahar SSK, a cooperative sugar factory in Maharashtra and one of the nine mills visited for this study, was one of MNES's pilot projects.

USAID Alternative Bagasse Cogeneration Project
A major source of international funding for bagasse cogeneration has been the United States Agency for International Development (USAID). Complementing the Indian government's efforts through the 1990s, USAID carried out an initiative from 1994-2003 called the Greenhouse Gas Pollution Project (GEP) with a special component for bagasse cogeneration (the Alternative Bagasse Cogeneration or ABC component). This project built on prior work by the USAID in the late 1980s in which a series of feasibility studies assessing the potential for bagasse cogeneration were carried out. Nine mills were chosen as demonstration projects and were screened for their financial viability. The criteria were that the mills had to have a capacity above 2500 TCD, and had to install boilers that were 60 bar and 480°C or above. The chosen mills were required to operate for 270 days per year only on biomass. In order to elicit participation by sugar mills, USAID issued a request for proposals inviting mills to apply for the grant assistance. The nine chosen mills received grant assistance of $1 million per project (or 10-20% of the project cost). Another component of this project involved a series of trainings and workshops, a quarterly newsletter, and outreach efforts to inform Indian sugar mills of the possibility of exporting electricity to the grid. Two mills visited in this study, TA Sugars and EID Parry, were USAID demonstration projects.

Asian Development Bank (ADB)
ADB is one of several international finance institutions that extend lines of credit to the Indian Renewable Energy Development Agency (IREDA) for loans for biomass cogeneration, some with portions reserved for bagasse cogeneration. A loan to IREDA from ADB contains a portion specifically dedicated to supporting bagasse cogeneration projects, and in 2004, had supported 130 MW of the technology.

Clean Development Mechanism (CDM)
In September 2008, India hosted 356 registered CDM projects, just under one-third of the global total, with an additional 690 projects in the process of applying for inclusion in the CDM (Fenhann 2008). Of these, 33 are bagasse cogeneration projects totally 534 MW capacity. During September 2008, 55 more bagasse cogeneration projects were in the CDM pipeline seeking approval for registration, amounting to 1050 additional megawatts if all are built.

Global Environment Facility (GEF)
The GEF was established in 1992 to support activities in developing countries that have positive benefits on global environmental problems. The GEF funds the "incremental costs" of activities with global environmental benefits, that is, the additional costs of performing a sustainable activity over the costs of a convention project. The GEF also provides technical assistance grants (for instance, it has provided $5 million to IREDA). Country or state governments apply for GEF funds by submitting project proposals. The GEF has initiated a project, entitled "Removing Barriers to Biomass Power Generation in India," part of which is aimed at developing a model for overcoming the financial barriers specific to bagasse cogeneration in cooperative mills in India. During the time this study was conducted this GEF project was still in its planning stages.

3. STUDY DESIGN AND METHODS

This research, primarily conducted in 2004, involved visits to nine sugar mills in Maharasthra and Tamil Nadu (see Table 4.2), review of project documentation from the support programs analyzed, and interviews with individuals involved in various aspects of the development of efficient bagasse cogeneration projects. The nine sugar mills chosen comprised five cooperative mills in Maharasthra, three private mills in Tamil Nadu and one state-owned mill in Tamil Nadu. We selected mills with varying situations in terms of stage of implementing bagasse cogeneration, financial standing, and size. In Maharashtra, we interviewed one mill that had successfully upgraded its boilers to enable high efficiency cogeneration through financial support from MNES, and five mills that had not yet done so. In Tamil Nadu, we visited three private mills—all of which had installed cogeneration—and one state-owned mill that had not as yet. We visited several highly profitable mills and loss-making mills running for only a faction of the crushing season. In each of these sites, we conducted interviews with senior management and engineers and technicians in charge of the mill's everyday operations.

We interviewed individuals working on bagasse cogeneration from the Indian government, non-governmental agencies (NGOs), multilateral agencies who were in charge of implementing renewable energy and/or climate change funding programs, energy consulting firms and research institutions in New Delhi, Pune, Chennai and Bangalore.

Table 4.2. Sugar mills visited

Name of mill and location	Ownership type	Installed capacity in 2004 (MW)	External funding source/s in 2004
Maharashtra			
Ajinkyatara	Cooperative	--	--
Baramati	Cooperative	--	--

Hutatma	Cooperative	--	--
Jawahar	Cooperative	25.5	MNES
Pravara	Cooperative	--	--
Tamil Nadu			
Chengalryan	State-owned	--	--
EID Parry	Private	24.5	USAID, MNES/IREDA
Rajshree Sugars	Private	15	None
TA Sugars	Private	110	USAID, MNES/IREDA, proposed CDM

4. BARRIER ANALYSIS AND EVALUATION OF SUPPORT PROGRAMS

When high efficiency bagasse cogeneration was first introduced in India in the early 1990s, several informational, technical and regulatory barriers prevented the rapid uptake of the new technology. Mill owners and managers were largely unaware of the technology, and did not have the technical expertise needed to implement it. Also, the lack of regulatory structures ensuring evacuation of the electricity from the mill and payment for it was major obstacle to the technology (Smouse et al 1998). By the time this study was conducted in 2004, mill owners and managers knew about the technology and its benefits, and had access to the substantial technical expertise that had been gained in the country. However, regulatory uncertainties were still a substantial barrier, and the poor financial conditions that had overcome both the sugar and power sectors made the high capital costs required to implement the technology even harder to access. Moreover, the cooperative sugar sector, comprising 60% of the total sugar production in India, faced additional financial problems due to their institutional structure, and today these problems present the most significant challenge to scaling up bagasse cogeneration. In the following sections we trace these shifts and discuss how well various international and domestic programs have addressed these barriers.

4.1. Informational and technical barriers

Prominent early barriers to the use of highly efficient bagasse cogeneration were informational and technical. Sugar mill owners and managers were largely unaware of the technology. Nor did they have experience working with high-pressure boilers, which involve a higher level of expertise and skill to run than do low-pressure boilers. The demonstration projects, trainings, workshops, newsletter and outreach from both the USAID and the MNES programs are considered highly successful at overcoming the informational barriers and lessening the technical barriers. A decade after the USAID project started in 1995, mill owners in India were widely aware of the practice of cogeneration with export to the grid. Demonstration projects proved that the technology was cost effective, and technical information was available to mills considering implementing the technology.

One problem with the USAID program was that its knowledge transfer component (e.g. newsletters such as Cane Cogen India, other publications, workshops, etc.) did not sufficiently reach out to cooperatives. Published materials were predominantly in English, whereas most cooperative leaders are not educated in English. Many of the study tours (e.g. to Mauritius) also required hefty participation fees that cooperatives could not pay.[65] In addition, though many mills in India expressed interest in being a USAID demonstration project in response to calls for applications, not one of the applicants was a cooperative mill.

4.2. Regulatory barriers

A persistent barrier to the dissemination of bagasse cogeneration was regulatory uncertainty. At the time that the technology was first being introduced in India, regulations had not yet been put in place ensuring that excess electricity produced by sugar mills would be purchased by state electric utilities or defining the terms and tariffs under which it would be purchased. In 1994, MNES issued guidelines to state electric utilities to purchase power from local generators at avoided costs, plus a 50% contribution to grid connection costs (WADE 2004). The tariff prescribed by MNES was \$0.049/kWh for 1994-1995 with a 5% compounding escalation per year thereafter, making it \$0.067/kWh in 2002. MNES also issued guidelines for wheeling and banking of power from distributed generators. Based on this, several states independently announced policies for electricity purchase from bagasse cogenerators.

Several sugar mill owners report that state electricity boards have historically not been creditworthy, which makes project developers and lenders cautious about investing in bagasse cogeneration. Many interviewees for this study recalled stories that state electricity boards in various states lowered the tariffs to bagasse cogeneration facilities mid-contract, failed to make payments for six months to a year, or reneged on contracts altogether. For instance, the tariff guidelines for cogenerated power issued by the Maharashtra electricity regulatory commission, faced considerable resistance by the state utility on the grounds that they did not strictly "need" the power from sugar mills. They insisted on compensation by the government for the higher tariffs they were being required to pay (Deo 2004). This initial resistance on the part of MSEB resulted in the delaying of the first cooperative bagasse cogeneration project in Maharashtra,[66] and in turn dissuaded other cooperatives from installing bagasse cogeneration since they believed that they would not be guaranteed a buyer for the electricity they generated. It was generally understood that the reason for these regulatory problems was that state electricity boards, already functioning at substantial losses, resisted purchasing power from independent power generators, especially at supportive rates they deemed excessively high. Experiences with broken contracts, lowered tariffs and delayed payments added substantially to the perceived risk of bagasse cogeneration by mill owners and lending banks.

The prospects of overcoming regulatory barriers are favorable. The Maharashtra electricity regulatory commission, established in the process of power sector restructuring, has made the state electricity board more accountable. Due to this, state electricity boards are less likely to rescind their power purchase agreements with bagasse cogeneration mills. Furthermore, the Electricity Act allows for open access to the grid. At least one private company (Indal Ltd.) has been allowed open access to the Karnataka state grid. This would give sugar mills the opportunity to sell power to customers directly, while they would only pay wheeling charges to the state electricity board.

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[65] Interview with engineer at cooperative sugar mill, June 2004
[66] Interview with engineer at cooperative sugar mill, June 2004

4.3. Financial barriers

In 2003-2004, drought in major sugar producing states led to low capacity utilization in sugar mills. In the same year, the price of sugar reached a low point in part due to low global sugar prices. These conditions together led to a serious financial crunch in the sugar industry for both private and cooperative mills.

Early implementers of bagasse cogeneration, including the nine mills participating in USAID's pilot program, had proved bagasse cogeneration to be a profitable technology—especially in that it provided benefits beyond the sale of sugar alone. At EID Parry and TA Sugars, two of the USAID pilot projects, the sale of electricity to the grid provided a steady flow of revenue. Electricity production is viewed as a major revenue source at these mills, and a more stable revenue source than sugar production whose price and yield fluctuates. Electricity is treated as one of their primary businesses. In the context of low sugar prices and drought, electricity production for sale to the grid has provided enough additional revenue to keep some mills out of bankruptcy.

Despite the cost-effectiveness of the technology, mills that had not implemented bagasse cogeneration typically faced a range of difficulties accessing the necessary investment capital—a major on-going barrier to the widespread use of this technology. Financial institutions were hesitant to lend to sugar mills to implement bagasse cogeneration because of the high risk involved. Bagasse cogeneration projects conventionally require investment of Rs. 1 billion (around $25 million), while smaller allied projects, e.g. alcohol distilleries, ethanol producing plants, require an investment of only 10 million rupees.[67] Smaller projects are often successful at attracting the requisite finance for these small projects, but bagasse cogeneration requires an order of magnitude investment that banks are not willing to risk in this industry.[68]

In 2004, most of the mills that had implemented bagasse cogeneration were large private sector mills. Some were owned by large multi-facetted companies such as EID Parry, a well-known company which produces a range of known products of which sugar was only one. Banks are likely to fund a bagasse cogeneration plant at such a company because of the financial standing of the company, even if they are not familiar with the sugar sector or the technology. Smaller lesser known mills had a much harder time finding debt. By 2004, the poor condition of the sugar sector, compounded by the poor condition of the electricity sector and the increased regulatory uncertainty this brought, made the sugar sector an even riskier investment, and made it even more challenging for mills to access financing.

Each of the support programs discussed in this paper had a role to play in helping some mills gain access to the investment capital needed to implement bagasse cogeneration. MNES's guidance to states to implement preferential tariffs, and various tax and other benefits, supported the cost effectiveness of the technology. However, these policies were not always carried out by states or the federal government, introducing substantial risk that undermined the incentives these program were designed to create. In addition to the problems with power purchasing contracts discussed above, MNES has been criticized for failing to deliver the subsidy payment for implementing the technology as per MNES policy.[69]

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[67] Interview at cooperative sugar mill, July 2004

[68] Interview with cooperative sugar mill owner, July 2004

[69] Interview with manager at private sugar mill, July 2004, who was still waiting to receive the MNES subsidy long after the bagasse cogeneration plant was installed

The IREDA multilateral lines of credit enabled some mills to acquire loans that otherwise would not have had access to debt, though at high interest rates. High interest rates charged by ADB and other lenders translate into high lending rates to mills by IREDA of around 13%, compared with 7-8% from local banks.[70] IREDA's positive appraisals were commonly used by local banks in their own lending decisions, and as such helped developers to refinance IREDA loans through local banks at much lower interest rates.

Similarly, USAID demonstration projects not only received a subsidy from USAID, but also benefited from the USAID "stamp of approval" from being chosen as a demonstration projects, which enabled them to receive better loan terms. It is also interesting to note that by choosing mills with the strongest financial standing and which were most likely to successfully implement bagasse cogeneration as their demonstration project, USAID was also choosing those mills which were most likely and able to implement the technology without USAID support. For example, TA Sugars had already invested in a bagasse cogeneration plant in one of its mills before the USAID project, and was preparing to shift two other plants to bagasse cogeneration without USAID support. Still, the USAID project was praised because of its success in supporting projects that were successful, and thus demonstrating the successful implementation of the technology.

The GEF project was specifically designed to address the financial barriers of cooperative sector mills. The CDM was designed to improve the financial returns from low emissions projects. Both of these programs are described in more detail below. Despite all of these programs, substantial financial barriers still exist, especially in the cooperative sector as described in more detail in the following section.

4.4. Barriers particular to the cooperative sugar sector[71]

In 1998, 55% of sugar mills in India were in the cooperative sector accounting for 60% of total sugar production in India (Godbole 2000). Almost half of these mills are in Maharashtra, and 99% of sugar produced in Maharashtra is in the cooperative sector. The cooperative sector has certain political and financial characteristics that make it difficult for them to stay financially solvent; as a result, more than one-third of the cooperative sugar factories in Maharashtra have been loss-making for the past three years, or are running at less than 75% of their capacity.

There are a number of reasons for the poor performance of cooperative mills and for the perception that they are more risky investments than private sector mills. Their institutional structure creates yet additional financial barriers to implementing the technology. First, cooperative mills have historically been smaller than private mills, commonly 2,500 TCD or less. Lower crushing capacity mills are less efficient than higher capacity ones, and it is costly to undertake mill expansion in order to install bagasse cogeneration. Second, as stockholders in the mill, farmers also own a share of the mill profits. These profits are paid to the farmers in the price paid for sugarcane. Therefore mills hold little capital that they can use for investments (Natu & Zade 2002), and certainly not enough to cover the level of equity needed to invest in cogeneration. Collecting the equity needed would involve a political process whereby farmers would agree to pay for the cost of the equity portion of the investment, such as through receiving

[70] Interview with IREDA employee, June 2004

[71] This whole section is based on: Ranganathan M. 2005. *Can Co-ops Become Energy Producers Too? Challenges and Prospects for Efficient Cogeneration in India's Co-operative Sugar Sector*. Master's thesis. University of California, Berkeley, Berkeley

a lower price for their sugarcane. Third, because cooperative mills are democratically run, with typical election cycles of five years for board members, there is a high chance of policy change if a new management board is elected. The perception that cooperative mills are less creditworthy expresses itself in state guarantees and collateral requirements by banks (UNDP 2005), that also, cooperatives are unable to meet. Fourth, some interviewees described the mills as lacking professionalism and not well-managed (also described in Natu & Zade 2002). The "un-corporate" culture of cooperatives is something international agencies are not used to, which is one reason they have focused on the more profitable private mills. The cooperative sector's poor financial health, perception by banks and the central and state governments as not creditworthy, and their lack of equity holdings all make it difficult for cooperative mills to access the equity and debt needed to invest in cogeneration.

Support programs to date have done little to help the majority of cooperative mills implement cogeneration. In 2006, only 50 MW from eight sugar mills were in the cooperative sector (Purohit & Michaelowa 2007), compared to approximately 600 MW in the private and public sectors. This is despite the higher subsidies cooperatives receive from MNES, and early MNES demonstration projects specifically in the cooperative sector. At the time of this study, the GEF project was being developed specifically to develop a creative financing program to address the specific barriers facing the cooperative mills.

5. DISCUSSION

Over the last decade, bagasse cogeneration faced a dynamic and varied set of substantial informational, technical, regulatory and financial barriers. These barriers changed over time, and differed between the private and cooperative sectors. Each of the programs designed to support bagasse cogeneration had a role to play in supporting the 711 MW of bagasse cogeneration currently installed, and no single program would have been successful on its own. MNES promotional policies, including capital and interest subsidies, a variety of tax benefits, and guidelines to states to implement preferential tariffs made bagasse cogeneration cost effective to implement in India. The USAID program is considered especially effective in increasing experience in country with the technology, bringing awareness of the technology to sugar mills throughout the country, and offering technical resources and support to mills considering implementing it. Various multilateral lines of credit offered through IREDA offered loans to some mills unable to access debt through other institutions. Still, to date, support programs have done little to address the unique financial barriers facing the cooperative mills due to the institutional structure of these mills, currently the most pressing barriers facing the technology.

Against this story of bagasse cogeneration development in India, we explore the effectiveness and limitations of the CDM and the GEF, and carbon trading and fund-based instruments more generally, as they are being discussed for inclusion in the post-2012 climate change regime.

Financial instruments currently being debated for the post-2012 regime

Under negotiations over the post-2012 climate change regime, proposals for structuring mechanisms which will support climate change mitigation in developing countries largely fall into two categories in country submissions and the research literature. One category comprises various credit trading mechanisms that create tradable carbon credits by comparing actual emissions to specified baselines. The Kyoto Protocol's CDM is a project-based credit trading mechanism, generating credits from projects in developing countries that supposedly reduce emissions. Proposals for the CDM post-2012 vary widely, from replacing it to expand it. Another set of proposals involves implementing a sector-based crediting trading mechanism such as "no-lose" sector-based targets (e.g. Schmidt et al 2006). Sectoral targets are targets applied to specific sectors rather than to the whole economy, and can be absolute (a defined figure covering the whole sector) or intensity-based (such as a target per kWh produced, or per ton of steel produced). No-lose targets are targets for which the country can sell credits if their emissions are lower than their target, but do not need to purchase credits if their actual emissions exceed their target.

A second category of proposals involves various types of global funds. There are various ways that the funds could be generated. Contributions from each country can be calculated based on principles of responsibility and capability (Mexico 2008), auction (Norway 2008) or taxes (Switzerland 2008). These funds would then be administered through an international body to support specific policies, programs and projects in developing countries. Add policies and measures, funding for which could be credit-based or fund-based

The CDM – limitations on the barriers it addresses

It is useful to ask how well a carbon trading mechanism like the CDM would address the past and current barriers to bagasse cogeneration if the additionality problem were solved. For example, we can ask if bagasse cogeneration in India would be an appropriate project type for the CDM if the CDM were limited to a defined set of project types (sometimes referred to as a "positive list"), foregoing the project-by-project additionality test.

The barrier analysis carried out in this study indicates that bagasse cogeneration in India should not be included in such a positive list. The CDM supports projects by improving their anticipated financial returns, adding an additional revenue source through the generation of tradable carbon credits. These additional revenues can make a marginally viable project viable (reflected in the investment analysis option of the standard CDM additionality-testing tool). Alternatively, additional revenues from the CDM can overcome project barriers by compensating for high financial, regulatory or other risks, or by otherwise convincing actors to take action to reduce project barriers (reflected in the barrier analysis option of the standard CDM additionality-testing tool).

While bagasse cogeneration is already cost-effective in India, with the help of MNES incentives, it is unclear how the CDM would overcome the other barriers facing the technology. The additional revenues from the CDM would not address the many reasons banks perceive that bagasse cogeneration, especially in the cooperative sector, is a risky investment. Also in most cases, it does not directly help cooperative mills access the equity needed to invest in the technology. While the CDM involves a new set of entities in the project development process, including CDM consultants, carbon credit purchasers, and auditors, none of these entities generally involve themselves in the details of project development and planning, and therefore do not engage directly in activities that overcome informational, technical or regulatory barriers. The CDM would not directly incentivize the outreach, workshops and newsletters that were so important when the technology was first being introduced in India, since those performing such activities would not be eligible for CDM credits.

An underlying rationale for the CDM, and market mechanisms more generally, is to put a price on emissions reductions, and let the market find cost effective reductions. Certainly it is a positive thing to change the relative prices of low and high emitting technologies. The CDM could potentially help mills access equity capital if their contract with a credit buyer involves up-front payments in addition to or rather than payment for credits once they are generated. Some credit purchasing agreements are already structured in this way. Also, we can envision that if CDM revenues were guaranteed for any new bagasse cogeneration plant in India, this could allow for lower tariffs, relieving the burden on ailing utilities and possibly the regulatory barriers.

In sum, even if the CDM were recognized as a subsidy for project types allowed under it, and the additionality problem were thus solved, the direct effects of the CDM are still limited and would not address many of the barriers that face this technology now, or have faced it in the past. Other mechanisms would still be needed to address a wider range of barriers.

Acknowledging competing (global) climate and (local) development goals

One debate in discussions about future financial transfer under international climate agreements is how climate and development benefits are to be weighed against one another. Within the climate policy literature, some argue that climate projects have the potential to have significant synergies with other domestic development goals (Davidson et al 2003), and are more likely to be successful if they also address these other goals (Swart et al 2003).

This study of bagasse cogeneration suggests that where priorities differ across scale (international, national and local) these priorities can compete with one another. This is an inherent problem with climate aid. Projects funded based on the international priority of climate change mitigation, run a risk of conflict with other more pressing local goals.

In areas of Tamil Nadu, due to drought and the resulting high price of biomass, paper mills are paying high prices for bagasse. A number of sugar mills that have implemented high pressure boilers for bagasse cogeneration have chosen to sell their bagasse to paper mills and burn coal in their new boilers instead, which would not be economical feasible with the old low pressure boilers. Many mills are choosing this option because the current high prices offered for bagasse makes it economic to do so. Therefore, projects meant to support bagasse cogeneration for climate change purposes, might actually lead to an increase in emissions by enabling mills to replace bagasse with coal throughout the year. This situation exists as long as the price of biomass remains high, and for mills located relatively close to paper mills.

A second example of a conflict between goals across scale is the interest of electricity companies to remain solvent on the one hand, and the national goal of increasing the renewable energy share on the other. In both Tamil Nadu and Maharashtra the state electricity boards went back on contracts they signed with bagasse cogeneration and wind power plants, rejecting MNES guidelines to offer preferential tariffs for renewable energy while they were running at losses. This conflict produces regulatory uncertainties that are a substantial barrier to investments in renewable energy.

Discussion of an alternative to credit trading mechanisms – international funds

The variety of barriers that have faced bagasse cogeneration over the last decade and the range of programs that have been important in enabling its implementation to date, imply that for this technology several support instruments working together would likely be more effective than a single instrument. While the CDM creates a price for carbon emissions reductions, treating all projects uniformly, according to the amount of emissions reduced, international funds like

USAID and the GEF are able to customize their projects to address the specific barriers and conditions of the technology they are promoting.

One reason the USAID program was as successful as it was, was that it was developed by individuals who had been working on renewable energy, and bagasse cogeneration specifically, in India for many years. They were familiar with the barriers to the technology and the local conditions under which the programs would be implemented and could design their program so that it is suited to these needs and conditions. While the GEF project was still in its planning stages at the time of this study, its intension of developing creative financing strategies for the cooperative sector directly addresses the most pressing barriers currently facing the technology. Such a program can only be successfully developed with in depth understanding of the cooperative sugar sector in India.

Still, bridging the global/local gap is a challenge for international funds. Several GEF projects in India supporting renewable energy technologies have been criticized by individuals familiar with them for the lack of transparency regarding how decisions are made as to what GEF proposals are funded, the amount of time it takes to go through the GEF approval process, and lack of accountability and oversight the GEF has to assure positive project results.

6. CONCLUSIONS

This study finds that bagasse cogeneration has faced layers of informational, technical, regulatory and financial barriers that have changed over time, and differed significantly between the private and cooperative sugar sectors. Each of the programs designed to support bagasse cogeneration had a role to play in enabling the bagasse cogeneration currently installed, and no single program would have been successful on its own. Some barriers to the technology needed directed efforts designed for the specific context in which they were implemented; simply subsidizing the technology or putting a price on carbon would not be enough. This, along with the fact that bagasse cogeneration is already cost effective in India, implies a limitation to the effects carbon trading mechanisms like the Kyoto Protocol's Clean Development Mechanism (CDM) could have in supporting the technology, even if the additionality problem were solved. Interviews at mills attempting to access carbon financing through the CDM indicate that additionality testing is a serious challenge to the effectiveness of this mechanism. Where climate (global) and development (local) priorities differ, projects that bring about international goals risk conflicting with more pressing domestic goals. Any effort to exploit the remaining 86% of the estimated national potential for high efficiency bagasse cogeneration will need to address the special financial and political conditions facing cooperative mills.

Chapter 5: Concrete emissions reductions in Shandong's cement sector: design options for a sectoral crediting program

1. INTRODUCTION

Sectoral crediting approaches are being proposed as a partial replacement for the CDM under the post-2012 climate change regime. Sectoral crediting shifts the metric of carbon offsetting from reductions by individual projects to reductions in an entire sector, and refers to a wide range of proposed programs. This chapter contributes an in depth analysis of the design of a sectoral crediting program in a specific sector in one region – the cement sector in Shandong Province in China. I offer a typology of sectoral crediting design options being discussed in academic and gray literature and in official post-2012 country submissions and negotiating texts. I then analyze these design options in the specific context of the Shandong cement sector focusing on the ability for sectoral crediting to avoid the main problems with the CDM documented in Chapters 2, 3 and 4. I assess sectoral program design options against three criteria: their potential to (i) effectively promote efficiency improvements, (ii) ensure that the number of credits generated by the program does not exceed the reductions enabled by it, and (iii) meet international standards for reporting and verifying emissions reductions. I find that for most design options, sectoral-scale crediting could perform worse than project-based offsetting along the criteria assessed. I outline two specific design architectures that may have the potential to effectively support verifiable emissions reductions in the Shandong cement sector without high risk of over-crediting those reductions if designed and implemented well. However, conservative decisions would be needed with regard to program scope and crediting baselines. The obstacles to an effective sectoral crediting program discussed below suggest that sectoral crediting is being included in international climate change agreements and domestic legislation prematurely. Carbon offsetting programs, whether project-based or sectoral-scale, add uncertainty to the emissions reduction estimates from cap and trade programs, must not be assumed to be workable, and must be adopted only after careful grounded design analysis in the specific sectors in which they are being considered for implementation.

The shift from project-based to sectoral-scale crediting in developing countries has been proposed for a number of reasons. First, the CDM has been heavily criticized by both the environmental and business communities, so much so, that is clear that changes to the CDM are necessary. From the climate perspective, the CDM is criticized for generating many credits from business-as-usual activities that do not represent real emissions reductions (California Air Resources Board 2009: 77, Haya 2009, Wara & Victor 2008). Project developers, traders and developing country governments criticize the CDM for being difficult to work with, in large part because the process of submitting a project for CDM approval is long, cumbersome and unpredictable (Haya 2009, International Emissions Trading Association 2010). A second issue is one of scale. The major shifts in development trajectory needed in developing countries are thought to require sector-scale effort, more than is achievable through a series of uncoordinated projects as are supported under the CDM (California Air Resources Board 2009: 77-78). Also, as industrialized countries commit to deeper post-2012 targets and the US comes on board as an active participant in the international climate change regime, a substantially larger demand for offset credits is expected. Sectoral crediting is thought to be able to produce a larger supply of credits. Third, some countries and industries are concerned that efforts to reduce emissions in domestic industries that compete internationally could lessen their international competitiveness and lead to the "leakage" of production to countries without such regulation (California Air Resources Board 2009, Meckling & Chung 2009). Lastly, sectoral crediting could bring developing countries more deeply into the climate change regime, by requiring the monitoring and reporting of emissions on a sectoral basis, and sector-level targets that could be binding or voluntary.

A range of approaches for the sector-scale crediting of emissions reductions in developing countries has been proposed and discussed in the literature and in country submissions to the UNFCCC. These fall broadly into three categories.[72] The most common conception of a sectoral crediting program would credit reductions in a sector as a whole against a sector-wide crediting baseline. Second, a reformed CDM could facilitate easier and more coordinated efforts in specific sectors or for specific technologies. Standardized criteria for CDM project approval set on a sector-level could more simply and predictably support certain technologies. A third family of crediting approaches with sector-scale focus credits reductions from a potentially wide range of policies, programs and other support measures. This proposal can be considered a form of credited Nationally Appropriate Mitigation Actions (NAMAs), and is sometimes referred to as "policy-" or "programmatic-CDM."

A number of studies examine the advantages and disadvantages of various types of credited and non-credited sector-scale programs in developing countries. Studies discuss a range of program designs generally (Sterk 2010) or focus on a sectoral no-lose target program that credits against a sectoral baseline (Schmidt et al 2008, Schneider & Cames 2009, Ward et al 2008). Some focus on sectoral programs for specific countries or sectors: China, Mexico and Brazil (Center for Clean Air Policy 2010) and transportation (Millard-Ball 2010a). These studies raise a range of concerns about programs that generate credits from sector-scale actions. Some question the effectiveness of creating financial incentives for government action, especially when payments are made for reductions after they have been achieved rather than up front (Sterk 2010). Some discuss the challenges of avoiding over-crediting emissions reductions, particularly with regard to measuring emissions reduced by NAMAs (Millard-Ball 2010b, Sterk 2010) and estimating a business-as-usual sectoral baseline (Millard-Ball 2010a, Millard-Ball 2010b, Schneider & Cames 2009), and the potential for creating perverse incentives for governments to refrain from action in order to generate more credits in the future (Ellerman et al 2008, Millard-Ball 2010a, Schneider & Cames 2009). Host country capacity to perform the necessary monitoring, reporting and verification has been raised as a potential challenge to sectoral-scale crediting (Cai et al 2009, Center for Clean Air Policy 2010). Though many of these studies discuss similar concerns, their conclusions differ widely. Some conclude that sectoral crediting should be avoided generally (Sterk 2010) or for specific sectors (Millard-Ball 2010a) and others conclude that sectoral crediting is promising if carefully designed (Center for Clean Air Policy 2010, Schmidt et al 2008, Schneider & Cames 2009).

I examine how and if these potential hurdles can be addressed. By performing a design analysis for one sector in one province, I am able to examine how a program might work in the particular context of the institutional culture and structure, government-factory relationships, opportunities for reducing emissions, etc. of this one particular sector, and uncover opportunities and potential hurdles that might not be seen by a more general analysis. I probe how the concerns raised in the literature might play out in this particular context. I focus this analysis on

[72] For a broader taxonomy of sectoral approaches, including credited and non-crediting options, see Meckling JO, Chung GY. 2009. Sectoral approaches for a post-2012 climate regime: a taxonomy. *Climate Policy* (9): 652–68.

identifying potential program designs that solve the main concerns raised about sectoral crediting programs, two of which are also the main critiques of the CDM: (1) providing effective incentives and support for emissions reductions and efficiency improvements, and (2) ensuring that the number of credits generated by the program does not exceed the reductions enabled by it. I discuss advantages and disadvantages of different design options on measuring, reporting and verifying (MRV) requirements, a third important concern about sectoral crediting, but a full discussion of the concerns over MRV is beyond the scope of this chapter.

The Shandong cement sector was chosen for this analysis for a number of reasons. First is its significance in terms of global emissions. Globally, the cement sector produces 5% of total GHG emissions; China produces approximately half of the world's cement; and Shandong produces the most cement of any province in China (10% of China's production) (Price et al 2009). Second, the cement sector is commonly viewed in the literature as promising for a sectoral trading program in part because it is a fairly homogeneous, somewhat internationally-traded product with a large potential for reducing emissions (e.g. California Air Resources Board 2009: 78, Schmidt et al 2008). Third, China is one of the countries for which sectoral trading is being proposed (e.g. Schmidt et al 2008). Fourth, there is domestic interest in China for reducing the energy consumed by cement and concrete manufacturing, and Shandong province has been particularly aggressive in its energy conservation efforts. Lastly, California is moving forward with the design of an international sectoral crediting program for a number of high-emitting sectors in specific developing countries under its cap-and-trade regulation (California Air Resources Board 2009). The Shandong cement sector is one of the sectors it is considering for this program.

Section 2 provides background on the Shandong cement sector and opportunities for reducing emissions in this sector. Section 3 offers a typology of sectoral crediting design options being discussed for application in developing countries. Section 4 explores how these design options might fare in the Shandong cement sector. The paper concludes with a policy discussion of appropriate options for the Shandong cement sector specifically, as well as for a basis structure for sectoral programs worldwide.

2. BACKGROUND ON THE SHANDONG CEMENT SECTOR

China's cement sector was estimated to be the third most CO_2 intensive (per ton of cement produced) in the world in 2005 (International Energy Agency 2007) because of its large proportion of small inefficient factories using inefficient vertical shaft kilns (VSKs). Only the US's[73] and India's cement sectors were more CO_2 intensive. China reinvigorated its economy-wide energy efficiency efforts in 2005, setting a domestic goal of reducing the energy intensity of its economy, in terms of energy consumption per unit of GDP, by 20% between 2006 and 2010. A range of measures has resulted in a reduction in energy intensity in China's economy over the last few years, including in its cement sector. Most important in the cement sector has been the closing of small production units with inefficient kilns and replacing the lost capacity with modern plants using rotary kilns. In 2006, Shandong was home to 980 inefficient VSK plants and only 61 newer larger rotary kilns plants. Just two years later, the proportion of cement produced by the more efficient rotary kilns had increased from 38% to 58% (Price et al 2009).

[73] Owing to the age of the factories and the use of energy intensive wet process kilns (Baron 2007)

China expects to phase out most of its VSK cement production lines by 2015.[74] In addition, there is ample opportunity to improve the efficiency of the rotary kiln factories. A 2009 study of sixteen rotary kiln plants in Shandong estimated a potential for decreasing the CO_2 emissions of these sixteen plants by 5% with cost effective measures,[75] and another 3% with other technically feasible improvements (Price et al 2009).

The Chinese and Shandong governments are aggressively implementing a range of programs and regulations expected to reduce emissions in the cement sector. Higher electricity pricing for the least efficient facilities in high-emitting industries led to the closing and upgrading of around 1300 inefficient firms in energy intensive industries throughout China between 2004-6 (Price et al 2010). China's Top 1000 Energy-Consuming Enterprises program aims to improve the efficiency of the largest energy consumers in the country, including many large cement factories. This program requires each participating facility to perform energy audits and develop energy conservation plans. The government provides various supportive trainings to plant managers under the program. The Chinese government has funded provincial energy conservation centers throughout the country for several decades, which provide information and assistance supporting industrial efficiency. The successful fulfillment of the associated conservation agreements is factored into the individual performance evaluations for provincial government officials and company managers, affecting their ability to receive annual awards, honorary titles, and promotions. The *Financial Rewards on Energy-Saving Technical Retrofits in China* program rewards factories for approved technical renovation projects in proportion to actual reductions in primary energy use. Sixty percent of the expected payments are provided upfront to help pay for the technical upgrades. The Chinese government has recently initiated a program to subsidize qualified efficiency projects performed by Energy Service Companies (ESCOs) called the *Accelerating Energy Performance Contracting to Promote the Development of Energy Service Industry in China* program which also provides support in proportion to the verified energy savings achieved.[76] In 2007 China published mandatory conservation standards for new and existing cement factories, regulating the coal, electricity and energy consumed per unit of clinker and cement produced and in specific plant processes.[77]

Cost effective and low cost opportunities to lower emissions exist at all stages of the cement production process (Price et al 2009). The cement production process starts with the transport of limestone and other materials containing oxides, normally clay or shale, to a cement factory. These raw materials are ground up and blended, and heated in a kiln to extremely high temperatures (commonly 1450 degrees Celsius) to produce clinker. Clinker is then cooled, ground up, and mixed with gypsum and other materials, to make fine powdered cement. Cement is mixed with water and binding materials, like crushed rock, gravel and sand, to produce concrete, which is poured to make buildings, bridges and other infrastructure.

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[74] Wang, Y., 2010. Cement Industry's Industrial Policy for the 12th FYP is going to be released. *China Business News*, September 17, 2010. Last accessed on December 9, 2010. http://finance.jrj.com.cn/2010/09/1704348191239.shtml

[75] Cost effective is defined as net negative cost using a discount rate of 30%, ignoring externalized social costs.

[76] See State Council of China, 2010. The Notice on Accelerating Energy Performance Contracting to Promote the Development of Energy Service Industry in China, April 2, 2010. http://www.gov.cn/zwgk/2010-04/06/content_1573706.htm

[77] See mandatory standards GB 16780-2007 (English translation: http://china.lbl.gov/sites/china.lbl.gov/files/Summary%20of%20GB%2016780-2007.pdf) and GB 50443-2007 (English translation: http://china.lbl.gov/sites/china.lbl.gov/files/Summary%20of%20GB%2050443-2007.pdf)

Typically a little over 50% of CO_2 emissions from cement manufacturing are from the chemical process of converting limestone into clinker. The intense heat breaks limestone ($CaCO_3$) down into CaO and CO_2. The CO_2 is released into the atmosphere and the CaO combines with the other oxide inputs to produce compounds that make up clinker. The largest opportunities for cost effectively reducing the emissions from cement manufacturing are associated with this phase of cement manufacturing (Price et al 2009). Emissions can be substantially reduced by lessening the amount of clinker in the final concrete product, either by blending clinker with a greater proportion of other materials to produce blended cement,[78] or by mixing cement with a greater proportion of alternative binding materials in the production of concrete. Another way to substantially reduce emissions in the kiln process is to replace the coal used to fire the kiln with alternative fuels, such as agricultural waste, non-agricultural waste like sewage sludge and saw dust, petroleum products like tires and waste oil, and hazardous waste (Murray & Price 2008). Third, the efficiency of the kiln can be improved, such as by lining the kiln with better insulating materials to prevent heat loss, improvements to process control systems, and waste heat recovery for power generation (Price et al 2009).

There are also various ways to improve the electrical efficiency in the pre- and post-kiln processes, with the potential for large greenhouse gas reductions since most of China's electricity is produced from coal. These include installing efficient high pressure roller presses, or more efficient roller mills for pre-grinding and grinding raw materials, motor and fan system improvements, more efficient roller mills for coal grinding, and process control systems (Price et al 2009).

Several interventions stand out as having the potential to enable these improvements in Shandong (Price et al 2009).[79] Capacity building and information are important to raise awareness of the advantages and use of blended cement, the availability of alternative fuels, potential cost savings from efficiency measures, and factory-level energy auditing tools. Analysis is needed on the use of blended cement in climates and construction patterns in China, and on the availability, market potential and impacts of alternative fuels, including biomass and waste-derived fuels, and including regulation requiring the use of those fuels. Financial incentives, along with improving the profitability of a project, can also raise the visibility of cost savings from efficiency measures to plant managers who are often most concerned about other parts of their business, and provide support for efficiency-improvement plans put forward by plant sustainability managers. Cement and concrete from new low carbon and carbon neutral production technologies[80] could be explored with information exchange and possibly demonstration projects. More research is needed on the specific barriers to cost effective measures.

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[78] Portland cement that is comprised of less than 20% additives other than gypsum made up around 60% of cement produced in China in 2007 (Price L, Hasanbeigi A, Lu H, lan W. 2009. *Analysis of Energy-Efficiency Opportunities for the Cement Industry in Shandong Province, China*, Lawrence Berkeley National Laboratory, Berkeley). Various materials, such as pozzolans, fly ash from power plants, and blast furnace slag from iron-making facilities, can be blended with clinker to produce various types of blended cement. Blended cement has different properties dependent on the materials used. Blended cement is often just as strong or stronger than Portland cement, but often takes longer to harden once poured.

[79] Also drawn from the years of experience Lawrence Berkeley National Laboratory has working in China on cement sector efficiency.

[80] New cement products with substantially lower CO_2 emissions or even negative emissions include CemStar, Energetically Modified Cement (EMC), and Calera.

3. TYPOLOGY OF DESIGN OPTIONS FOR A SECTORAL CREDITING PROGRAM

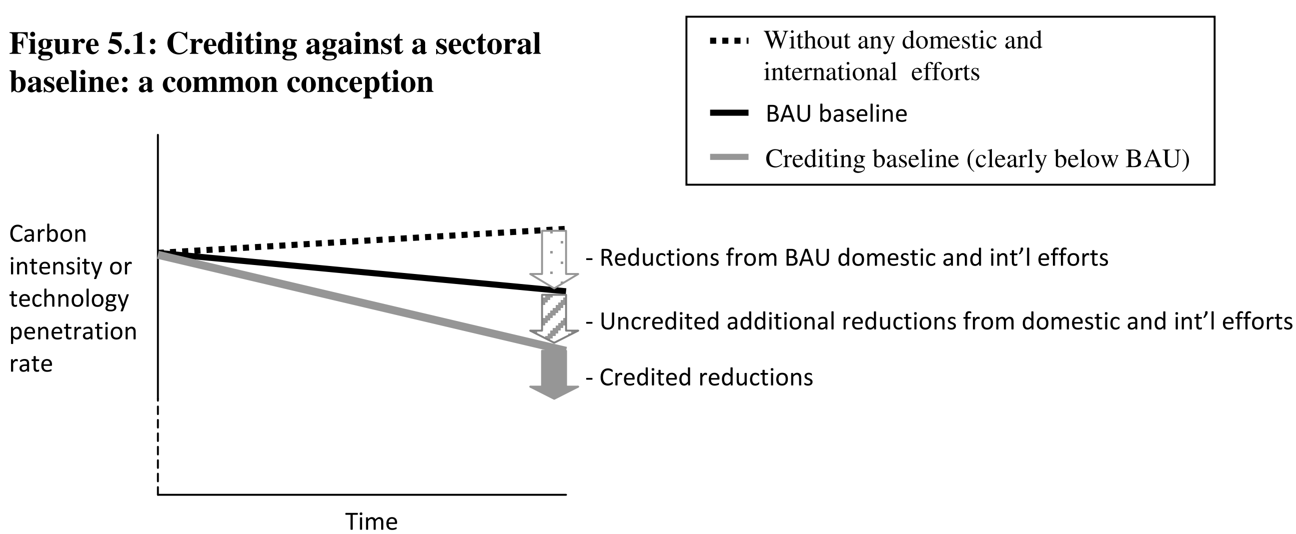
As mentioned above, proposals for sectoral crediting in developing countries largely fall into three categories:

(i) crediting against a sector-wide baseline
(ii) reformed CDM using standardized project eligibility criteria
(iii) credited NAMAs.

One conception of program which credits against a sector-wide baseline (Schmidt et al 2006) has had traction in climate policy circles. Key elements of this proposal form the basis for sectoral crediting programs being proposed for inclusion in California's cap and trade program (California Air Resources Board 2009), in US federal legislation (American Clean Energy and Security Act 2009) and under a post-2012 international climate change agreement (Belgium and the European Commission on behalf of the European Union and its member States 2010). This proposal establishes a crediting baseline for a participating sector against which emissions are measured. As proposed, this target would be voluntary, or "no lose," rather than binding, meaning that the country can sell emissions credits if its emissions are below the crediting baseline, but does not have to purchase emissions credits if its emissions are above the target. Targets can be a fixed "absolute" value, such as a total number of tons of CO_2 emissions taken as targets by Annex 1 countries under the Kyoto Protocol, or they can be intensity based, defined as a certain quantity of emissions per some other unit, such as per ton of cement produced or per kilowatt hour of electricity produced. Targets can be in terms of tons of CO_2-equivalent, or technology penetration rates, such as the percentage of cement produced from plants that use waste heat recovery power generation.

In this proposal, a crediting baseline is set against which credits are generated (gray line in Figure 5.1). This crediting baseline is deeper than optimistic business-as-usual (BAU) forecasts for the industry (black line in Figure 5.1) to assure that credits are not generated for activities not resulting from the program. The BAU forecast should take into account BAU domestic and international efforts that are expected without the crediting program (dotted downward arrow). Action, some of which would be supported internationally, would be needed to bring the emissions levels down to the crediting baseline before credits start to be generated (striped downward arrow). All reductions below the crediting baseline are credited (gray downward arrow).

Figure 5.1: Crediting against a sectoral baseline: a common conception



Under this proposal, credits would be generated by the Shandong government, rather than by each individual cement factory. It would be difficult for factories to be directly awarded for making reductions, since the total number of credits generated depends on the actions taken by all emitters in the sector together. The international program would reward the Shandong government periodically for reductions made below the crediting baseline after reductions are made. It would be up to the government to pass those incentivize onto the factories making the reductions, which they could do through financial incentives, regulation, informational programs, demonstration projects, etc. The Shandong government could then sell those credits to credit buyers. Procedures for reporting and verifying sectoral emissions inventories and total clinker and cement produced would need to be established.

As a second category of design options, proposals for reforming the CDM expand the mechanism so it has a more sectoral- rather than solely project-based focus. Proposals for replacing project-by-project additionality testing with standardized criteria to determine project eligibility for offsetting have been put forward by governments for use in climate policies on a range of scales (American Clean Energy and Security Act 2009, California Air Resources Board 2009, UNFCCC 2010: 41 para 9). Standardized criteria would identify project types with high likelihoods of being additional based on criteria such as project type, location, size, construction start date, and efficiency level. All projects that meet these criteria are automatically registered under the CDM. Standardized criteria could include, for example, all wind power development in sub-Saharan Africa, or all cement factories in China that exceed some defined efficiency level. Currently CDM methodology AM0070 uses standardized criteria for project eligibility. Under this methodology, all refrigerators manufactured that are within the 20th percentile of efficient refrigerators in the host country are automatically considered additional and eligible to generate credits under the CDM. A reformed CDM would function under the same or similar institutional arrangements as the current CDM. Standardized criteria reduce the transaction costs and uncertainty associated with the CDM application process, making the CDM more predictable and therefore effective at supporting new projects. However, this reform would need to avoid allowing larger numbers of non-additional projects to more easily register and generate credits.

Credited NAMAs would generate credits from reductions resulting from government programs or policies (Republic of Korea 2009a, Republic of Korea 2009b). The proposals for credited NAMAs are very similar to proposals for programmatic- or policy-CDM, which would expand the CDM to cover policies and government programs. In the international climate change negotiations, “NAMAs” is a broad term meaning any activity carried out in a country that reduces emissions. The reductions resulting from these actions could be estimated and credited. Appendix II of the Copenhagen Accord, signed at the 15th Conference of the Parties that took place in December 2009 in Copenhagen, is a list of NAMAs developing countries pledge to carry out.[81] The NAMAs submitted to this list fall into three categories. One category sets targets in terms of absolute emissions, emissions intensity or technology dissemination at the national or sectoral level. A second category names specific investment in projects, such as investment in specific hydropower and energy efficiency projects. A third category of NAMA, that is distinctly different from the types of activities covered under sectoral crediting and from the current CDM, is the crediting of policies or programs. Appendix II contains only broad commitments in this third category, such as supporting energy efficiency and performing analysis of actions that can be taken. For this paper, credited NAMAs refer to specific actions that would fall under the third

[81] Appendix II of the Copenhagen Accord- Nationally appropriate mitigation actions of developing country parties http://unfccc.int/home/items/5265.php (Last accessed on November 15, 2010)

category of NAMAs – the crediting of the emissions reduced by specific policies and programs. Credited NAMAs, as defined here, differs from crediting against a sectoral baseline in a key way. Programs that credit against a sectoral baseline start with a crediting baseline, and credit any reductions below that baseline, blind to the means of reducing emissions. Credited NAMAs focus on a specific policy or program and estimate the emissions it reduces.

To examine the advantages and disadvantages of these three categories of sectoral crediting programs (crediting against a sector-wide baseline, reformed CDM using standardized project eligibility criteria, and credited NAMAs) and the variations within them, I identify and discuss four key design decisions. These design decisions capture the most important differences among the range of possible design architectures:

(1) ***Sector-scale vs. factory-scale crediting**:* Will reductions be measured for the entire sector (crediting against a sectoral baseline) or per participating factory (reformed CDM)?
(2) ***Payment to government vs. to factories**:* Will payments for credits be made to the Shandong government (crediting against a sectoral baseline and NAMAs), or directly to participating factories (reformed CDM)?
(3) ***Full emissions inventories vs. technology/program-based crediting**:* Will emissions be measured comprehensively through emissions inventories, or will the program focus on the increased use of a few specific technologies? (Can apply to all three categories of sectoral programs.)
(4) ***Payment for credits vs. upfront payment for program**:* Will payments be made through the purchase of credits, or upfront in the form of capacity building, technology subsidies, etc? Or a combination of the two options? (Can apply to all three categories of sectoral programs.)

The rest of this section discusses the advantages and disadvantages of each of these design options, focusing on how well they avoid the main problems with the CDM using the following criteria and sub-criteria:

- Effectively support emissions reductions
  - Match the support needed to enable cost effective reductions and overcome the barriers to emission reduction activities
  - Provide benefits with minimum uncertainties
- Avoid over-crediting emissions reductions
  - Avoid crediting non-additional reductions (reductions not caused by the program)
  - Avoid perverse incentives to increase emissions
  - Enable actions that effectively reduce emissions, but would not have been pursued without the crediting program (are additional)
- Data availability
  - Require data that are available, reliable and monitorable
  - Minimize transaction costs in data gathering

The design of a sectoral crediting program requires assessments of both the effectiveness of the program in the context of the specific sectors it is applied to, and the ability to measure the program's effects. If we could measure the emissions reduced by the crediting program with a high degree of accuracy, understanding the pathways of that influence would be less important.

Or if we could be confident about the influence the program will have, conservative assumptions could be applied to avoid over crediting. If both emissions reduction estimates and the actual of influence of the program are uncertain, both need to be assessed together.

4. ADVANTAGES AND DISADVANTAGES OF THE DESIGN OPTIONS IN THE CONTEXT OF THE SHANDONG CEMENT SECTOR

4.1. Sector-scale vs. factory-scale crediting

The most significant design decision distinguishing different architectures of a sectoral crediting program is whether that program will measure emissions reduced in the sector as a whole, or only in each participating factory as is done by the current CDM. Sector-scale crediting involves the establishment of a crediting baseline for an entire sector (as illustrated in Figure 5.1 above). Credits are generated only when emissions or technology penetration rates in the sector as a whole are better than the crediting baseline. With factory level crediting, each factory that implements a technology or meets emissions requirements, and that meets the requirements of the program, will be able to generate credits, regardless of actions taken in other factories.

An important distinction between these two approaches is who receives carbon credits through the program and therefore who is responsible for taking action to reduce emissions. Factory level crediting would typically credit each participating factory directly. Crediting against a sectoral baseline requires credits to be generated by the government.

Sector-level crediting has the advantage of measuring emissions more comprehensively. Crediting on a factory-level ignores increases in emissions in non-participating factories. In this way, sector-level crediting avoids "leakage" within the sector. "Leakage" occurs when an increase in efficiency in one factory *causes* a decrease in efficiency in another factory. This is best explained through an example. If one factory increases the proportion of blended cement it produces, but demand for pure Portland cement does not change, another factory may increase its production of Portland cement to meet demand. In total, the amount of blended cement and Portland cement produced may not have changed, though the increase in blended cement in the participating factory could be credited.

The comprehensiveness of sectoral-scale crediting comes with several important trade-offs. A disadvantage of sector-level crediting is the greater uncertainty associated with carbon credit payments. As discussed in previous chapters, the ability of the CDM to influence project development decisions is compromised by the high levels of uncertainty associated with the benefits of the CDM. When crediting is done on a sectoral-level, as opposed to a factory-level, the uncertainties are even greater. Since credits are only generated after the baseline is achieved sector-wide, and since that baseline needs to be below BAU in order to prevent over-crediting, the number of credits that will be generated by the program is uncertain when first efficiency investments are made. The Shandong government must first take action to reduce emissions to the crediting baseline and beyond, and only at the end of the crediting period will know how much they will be paid for their efforts through carbon credits. In contrast, factory-level crediting could generate credits for each participating factory, in predictable amounts, as soon as they reduce emissions according to program requirements.

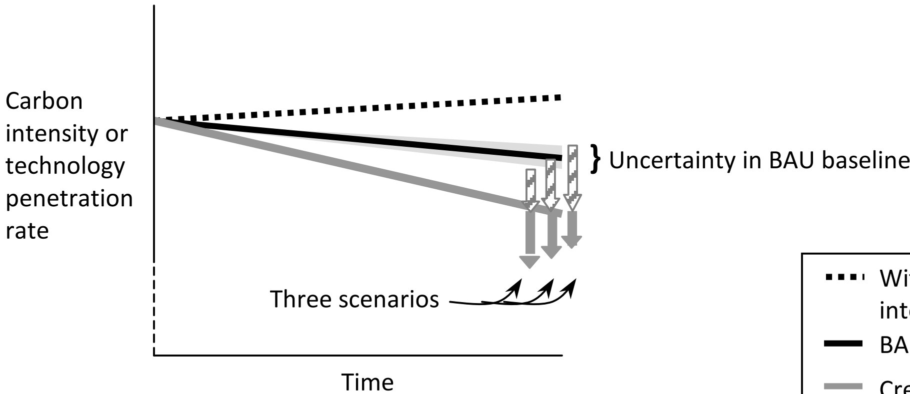
A second possible disadvantage associated with the comprehensiveness of sector-scale crediting is the greater data requirements. Factory-level crediting is less data intensive since only factories that voluntarily participate in the program need to release data. The data requirements of a sector-level crediting program can be managed, in part, by carefully defining the boundary of the sector. In Shandong, since the majority of cement factories are small inefficient vertical shaft kiln plants that are being phased out, requiring all of these plants to monitor and report emissions is challenging, and should soon be irrelevant. It may make more sense to define the crediting sector as the subset of larger and more modern cement plants for which data collection is more manageable. On the other hand, crediting all cement plants creates incentives to carry out the phase out of the factories that use small inefficient vertical shaft kilns. These data concerns deserve more analysis.

Additionality is a challenge for both sector-scale and factory-scale crediting. Factory-level crediting under a reformed CDM credits actions in all factories that meet the eligibility criteria of the program, regardless of whether the actions are additional for each particular factory. For example, if all cement factories in Shandong that use alternative fuels in their kilns were categorically allowed to generate credits, the program would credit the BAU alternative fuels that would have been used without the crediting program. A deration rate, sometimes referred to as a "discount rate," which can also be in the form of a conservative baseline, is therefore needed to account for the proportion of BAU activities that would generate credits under a factory-level program. The deration rate discounts the number of credits generated by each participating factory. Determining such a deration rate is arbitrary since it involves estimating the proportion of new projects that will be enabled by the crediting program to BAU project that will be done regardless of carbon crediting long before the total number of projects is known.

The common conception of a program that credits against a sectoral baseline would set a crediting baseline that is clearly below BAU to avoid over-crediting, and would incorporate capacity building and other non-credited activities into the program in order to help bring emissions down to the crediting baseline. Given the uncertainties associated with BAU forecasting, it can be difficult to determine a baseline that is both clearly below BAU and not so low to be irrelevant (Millard-Ball 2010a). If the baseline is set above actual BAU projections, too many credits will be generated. If the baseline is set far below actual BAU, then it will be irrelevant, since the baseline will be hard to meet, and even if it is, the quantity of credits will be low compared to the effort exerted (ibid). The feasibility of setting an appropriate below BAU crediting baseline is a function of the uncertainty in BAU projections and the expected influence of the crediting program. Figures 5.2 and 5.3 describe this visually.

If the uncertainty in the BAU forecast is small compared to the expected effect of the crediting program on emissions, as represented in Figure 5.2, then over-crediting is unlikely or unimportant. In Figure 5.2, the gray area behind the black line shows the uncertainty in the BAU projection, which is small compared to the expected uncredited and credited reductions spurred by the program, represented by the downward arrows. The middle of the three scenarios presents the uncredited and credited reductions if the assumed BAU baseline is correct. The left arrow shows what happens if actual BAU emissions are below the projected BAU baseline, and the right portrays actual BAU emissions as above the forecasted BAU baseline. Assuming the same amount of reductions below BAU for each of the three scenarios, a larger proportion of the reductions are credited if BAU emissions are below the forecasted value (the left arrow) than if the BAU projections were correct. If actual BAU emissions are higher than BAU projections, more effort is needed to bring emissions down to the crediting baseline and a smaller proportion of reductions are credited (the right arrow). Since the uncertainty in BAU projections is small compared to the effect of the crediting program, the program works for each of these scenarios.

Figure 5.2: Crediting against a sectoral baseline: uncertainty in the baseline is *small* compared to the effect of the program



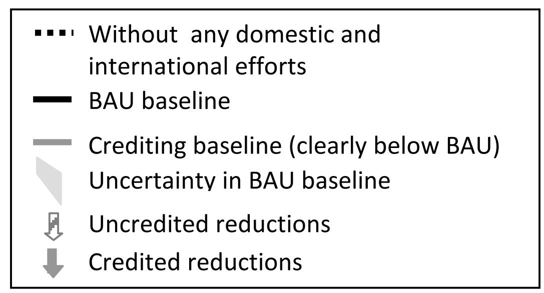
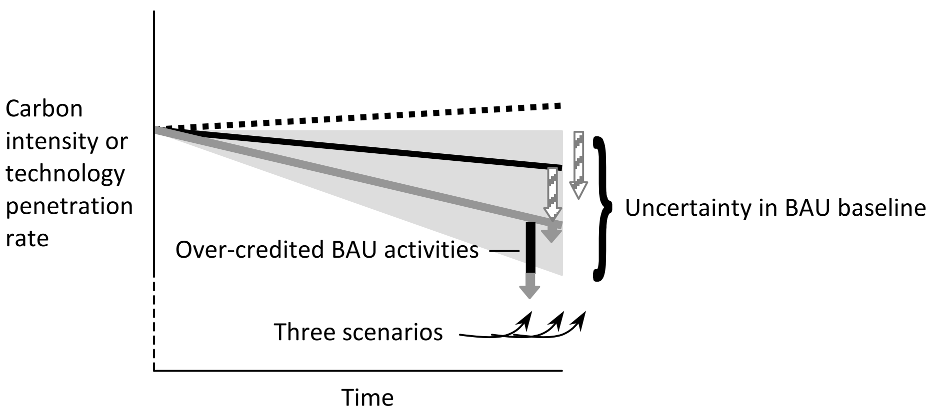


Figure 5.3: Crediting against a sectoral baseline: uncertainty in the baseline is *large* compared to the effect of the program



In Figures 5.2 and 5.3, the three arrows represent three BAU scenarios: a deep BAU scenario, a middle scenario in which the crediting baseline accurately represents BAU emissions, and a high BAU scenario. The total sizes of the arrows are the same representing the same quantity of reductions for each scenario, but each shows a different distribution between credited and uncredited reductions.

If uncertainty in BAU emissions is large compared to the reductions expected from the crediting program, illustrated in Figure 5.3, then the risk of either over-crediting or setting an irrelevant baseline is high. Figure 5.3 shows a larger range of possible BAU scenarios in gray, and a smaller expected effect from the crediting program represented by the shorter downward arrows. Again, if the projected BAU baseline were accurate (the middle scenario) some of the reductions made will be credited and some uncredited. If actual BAU emissions are low and below the crediting baseline (the leftmost arrow), the program would generate credits from BAU activities. If actual BAU emissions are high, then the crediting part of the program is irrelevant, since much more effort would be needed to bring emissions down to the crediting baseline in order to start generating credits (the rightmost arrow).

Figures 5.2 and 5.3 illustrate the effects of uncertainty in emissions forecasts, but not the uncertainty in the magnitude of the effect of the program (uncertainty in the length of the downward arrows). Since the effect of the program is also uncertain, that uncertainty must also be taken into account in the design of the program. This uncertainty would be incorporated into Figures 2 and 3 as error-bars around the heads of the arrows.

Evaluating a program that credits against a sectoral baseline would require comparing the uncertainty in BAU projections in Shandong's cement sector with the expected effect of the crediting program, taking into account uncertainty in that effect. Emissions or technology forecasting can be based on (i) government targets, planning documents, anticipated policies and expected industrial trends, and/or (ii) extrapolated historical trends. Government targets and plans are not always accurate. The Chinese government sometimes exceeds its sector-scale policy targets and sometimes falls far short of them. For example, in its 11th year plan, the targets set by China's Top-1000 Program and its program to close small inefficient industrial plants in some sectors were met two years early (Levine et al 2010) implying that the emissions reduced by these programs will most likely exceed their targets by 40% or more. China met its goal of commissioning an additional 73 gigawatts of hydropower one year early.[82] However, programs in other sectors did not meet their goals. For example, a program to close small inefficient electrolytic aluminum production facilities reached only 16% of its 2010 target by 2008, and little progress was made towards targets for energy savings from upgrading existing buildings and heat system reform (Levine et al 2010).

A second possible concern with taking government targets and plans into account in baseline setting is that doing so creates "perverse incentives" for the government to scale back their targets and plans in order to receive credits for the actions it expects to take. Such perverse incentives are not a concern today in China, given its well established planning processes. It could become a concern in the future if revenues earned by a sectoral program once established are large enough. Further, defining the crediting baseline on future projections in one country or province could send a signal to other governments to wait to take action until they can receive credits for those actions.

Basing the crediting baseline on historical trends or other indicators, instead of expected government actions, would avoid creating such perverse incentives. The California Air Resources Board, in designing an international sectoral crediting program, has progressed the furthest in the forestry sector. It has proposed basing the business-as-usual scenario on historical trends in order to prevent perverse incentives (California Air Resources Board 2010a). Historical trends also have not been good predictors of future trends (Schneider & Cames 2009). For example, in China, energy intensity per GDP decreased steeply between 1980 and 2000, increased between 2000 and 2005, and started decreasing again in 2005 in response to Chinese government policy (Levine et al 2009). Historical trends would not have predicted the ups and downs of China's energy intensity over the last three decades.

[82] Data on Chinese hydropower capacity are from http://www.cec.org.cn/news/.

4.2. Payment to government vs. payment to factory

Under the current or reformed CDM, payments for credits are made directly to the participating factories. The credit buyer negotiates a credit purchasing agreement directly with the CDM project developer; the host country government is involved only in providing an approval signature attached to the application for CDM registration. Crediting against a sector-wide baseline and credited NAMAs both require credits to be generated by the government. It is not practical for credits to be generated directly by factories when emissions are measured for the whole sector, since the total quantity of credits generated is a function of the actions taken by all emitters in the sector. Incentives for factories to reduce emissions would be created by policies/programs/regulations/enforcement by the Shandong government.

The effects of directly incentivizing the private sector versus supporting government programs and policies vary sector to sector and country to country. In China, the central and provincial governments have been the main drivers promoting industrial efficiency. Their efforts over the last three decades have lead to a dramatic decoupling of GDP growth and energy (Levine et al 2009). The large existing potential for cost effective efficiency improvements implies that further improving their financial outcomes may not do much to overcome their barriers. Financial incentives are only one of several measures understood to support emissions reductions in Shandong's cement sector mentioned above in Section 2. Capacity building and various analyses are also understood to be promising and potentially cost effective avenues towards cement sector efficiency improvements but would not likely happen as a result of directly crediting factories for emissions reductions.

The influence of carbon credits on government action is both weaker and more difficult to verify than on private sector investments. The private sector is primarily motivated by profit generation; improving project profits through the sale of carbon credits can change private sector investment decisions. Chapter 3 above shows that even with a relatively straightforward bottom line, it is extremely difficult for an external auditor to verify the go/no-go influence of carbon credits on individual CDM projects. Project developers can often game the financial assumptions used in CDM registration applications to show that cost effective projects are not cost effective. Additionality testing is even more difficult with public sector actions. While revenues can influence governments, it is often only one influence among a complex set of other factors affecting policy formation and enforcement. Governments often implement policies that are not cost effective in purely monetary terms; and many policies that lead to efficiency improvements and emissions reductions are free or revenue generating for the government.

Revenues from a sectoral trading program could influence the actions of a government if the government wishes to take action that would reduce emissions, but does not do so because of the cost of those actions. The prospects of future revenues can also influence government action to raise revenue for other programs or because of corruption. Also, the increased attention given to efficiency improvements by a concentrated international program could invigorate domestic action and enforcement. But how is it possible for an external agency to understand and verify these effects to assure that the program is having an influence at least as large as the credits it produces?

A sectoral crediting program may be able to support government policies, programs or specific technologies that would not have gone forward or been implemented as quickly without the crediting program. In the Shandong cement sector several efficiency technologies have large efficiency improvement potentials but fairly costly and are not being widely installed, such as high efficiency roller mills for grinding raw materials (Price et al 2009). Such activities may not be widely used in the near term without financial or other incentives and could potentially be enabled by a crediting program. Second, there is a large potential for reducing emissions with the use of alternative fuels in cement manufacturing, but little progress has been made so far. A focused international support effort starting with an assessment of the availability of alternative fuels in China could spur this technology option forward more quickly than without that support. Third, new low carbon and carbon neutral cement and concrete technologies could have a large potential in China's rapidly growing cement sector; international interest in exploring the use of these technologies in China and support for pilot factories could possibly lead to a much faster adoption of these technologies in China.

The sectoral program could be designed to target these actions with a credited NAMAs program, categorically making projects of these types eligible for CDM credits, or through a program which credits against sectoral technology penetration rates. There are several challenges with each of these approaches. First, the financial benefits from carbon credit sales only directly address the main barrier to the first example above – the higher cost technology improvements. The main impact of the crediting program on the other two examples – alternative fuels and new low-carbon cement technologies – is the initial international support in the form of information, involvement in research, and possibly support for demonstration projects. Second, also focusing on the first option above – the higher cost efficiency improvements – does it make sense to focus a crediting program on more costly technologies that are more likely to be additional rather than first supporting the faster implementation of less expensive options? Third, the national Chinese and Shandong governments are already actively implementing programs to improve the efficiency of cement manufacturing in China, and have been successful in their efforts so far. Those technologies that are that are candidates for successful near-term implementation might also be pursued by the government without international support. This crediting program would be limited to a few technologies, such as possibly the ones named just above. Inside knowledge of the considerations of the government and grounded knowledge of opportunities in the sector is needed to assess the influence of international involvement. Such inside knowledge would be difficult to require for a broad-reaching international crediting program.

4.3. Full emissions inventories vs. technology/program-based crediting

Full emissions inventories set a crediting baseline in terms of total emissions from the cement sector or individual cement factories. Full emissions inventories are calculated by estimating total fuel, electricity, limestone and other raw materials used in the cement-making process.

Technology- or program-based crediting estimates and credits the emissions reductions resulting from specific technologies or from a specific conservation program. Examples of sector-scale technology penetration rates baselines are: a certain percent of fuel energy in cement kilns from agricultural waste, or a certain percent of raw materials ground with high efficiency roller mills. Emissions reductions are credited for reductions estimated from the use of the technology exceeding the baseline.

Measuring emissions comprehensively with a full emissions inventory has two main advantages. First, everything that a factory does that reduces emissions can be credited under this option. The emissions from a cement plant are not only affected by the technologies installed, but also by how technologies are used and how the plant is maintained. Full emissions inventories reward the effective use of technologies and efficient plant management practices, not just the implementation of technologies and therefore more accurately measure actual changes in plant emissions. A second advantage is that comprehensive accounting can allow for greater flexibility in how reductions can be achieved, and avoid "choosing winners." All actions taken by the Shandong government or individual enterprises are counted, rather than only those technologies or actions explicitly included under a technology-based program.

A technology-based approach also has several important advantages. First, it can be easier to monitor whether a technology has been installed and is functioning, than to conduct full emissions inventories of entire cement factories. China policies already involve the monitoring of the use of technologies and so implementing this program will fit easily into monitoring and enforcement mechanisms already being used (Center for Clean Air Policy 2010). Second, a technology-based program could start small, focusing on a few technologies, and then be expanded. This is especially advantageous in China where many policies and programs are started on a trial basis and then expanded. Third, for some technologies, business-as-usual technology penetration forecasts can be more accurately estimated than the emissions trajectory of an entire sector. Emissions intensity in the cement factory can be influenced by a large number of factors making it difficult to set an accurate business-as-usual baseline for the emissions of the entire sector. It may be easier to trace the influence of the support program if it focuses on a few technologies. This is especially true for technologies that are not cost effective on their own, or for focused programs that promote a technology that most likely would not have been pursued by the host country on its own.

Fourth, basing a program on full emissions inventories may possibly involve greater difficulty accounting for leakage, or changes in emissions outside of the sector caused by the program, since the program is blind to the specific activities and technologies used to bring down emissions. For example, if the boundary of the program is defined as the cement industry, promising opportunities for reducing emissions in the lifecycle production of concrete can be overlooked. Blending with alternative materials typically happens either at the cement production stage or at the concrete production stage but not both. So crediting blending at the cement factory can ignore missed opportunities to blend cement with other materials in the production of concrete.

4.4. Payment for credits vs. upfront payment for program

Most proposals for sectoral crediting programs assume that payments will be made in the form of carbon credit purchases, as is done with the CDM. Another option is for the support program to be funded upfront. The funding entity would then receive the number of credits estimated to result from that program after emissions are reduced. This approach decouples the amount of money paid and the number of credits received.

The main difference between these two approaches is who takes the risk that emissions will not be reduced as expected. When payments are made in the form of credit purchases the risk is borne by the government or the participating factories. Action is first taken in China to reduce emissions, and credits are rewarded based on the results of those efforts. The government and factories take the risks that the actions will not be successful, that credit prices will be lower than expected, and possibly that the credits will not be purchased at all. When upfront payments are offered, program risk is taken by the entity offering the upfront payments.

Upfront payments could be considered for two reasons. First, it eliminates the uncertainty associated with the benefits of the crediting program to the factory or the Shandong government. Second, the funder can support emissions reductions through a range of support measures, rather than only through paying for carbon credits. In the Shandong cement sector, a funder could work with the Shandong and Chinese governments on the various capacity building and analysis efforts identified in the background section above. These efforts could be necessary to enable the installation of certain technology, or could be less costly than financial incentives in the form of carbon credit sales, if they address non-financial barriers. A program involving upfront payments can take many forms, including capacity building, upfront subsidies, low interest loans, technical support, etc.

An advantage of paying for carbon credits in proportion to the reductions achieved is providing ongoing incentives based on performance. This avoids the problem, so common with development programs of, for example, solar panels sitting on rooftops not generating electricity (Green 2004), or technologies being installed in cement factories without being used effectively. Payment for credits creates a financial incentive not just to install a technology, but to properly run it and maintain it.

Second, while capacity building, analysis, technological assistance, etc. can all be important efforts to promote conservation in the cement sector, it can be difficult to measure the emissions reductions resulting from such efforts. How do you quantify the emissions resulting from information workshops, for example? More importantly, it can be difficult to determine how much of the reductions made in a sector are a result of the international program, versus a result of domestic efforts taken by the Chinese or Shandong governments and by the factories themselves. If all reductions below a baseline result in credits that are given to the payer of the international program in exchange for their upfront support, too many credits can be granted, and the incentive for domestic action will be lessened since credits for the reductions will go abroad.

This last concern could possibly be overcome if credits are shared between the participating industrialized and developing countries. Another possibility is for some proportion of the expected credit payments to be made upfront to help pay the costs of technology installment as is currently being done with the *Financial Rewards on Energy-Saving Technical Retrofits in China* program through which the Chinese government pays for reductions in primary energy use in participating factories.

5. CONCLUSIONS

This design study of a sectoral crediting program in the Shandong cement sector reveals a number of hurdles to implementing such a program. I discuss in turn the three main categories of sectoral crediting programs – crediting against a sectoral baseline, reformed CDM using standardized eligibility criteria, and credited NAMAs.

Crediting against a sectoral baseline has the challenge of determining a baseline that is both below BAU but also not too low to be irrelevant. BAU projections involve uncertainty that must be compared to the expected effect of the program. Revenues from sectoral-scale crediting are even less certain than from factory-scale crediting such as under the CDM, implying even weaker incentives generated by the program. Crediting against a sectoral baseline requires governments, instead of the private sector, to generate credits. Since governments have a range of motivations for its choice, design and enforcement of policies and programs, revenues have a weaker effect on decision-making and it is more difficult for an external program regulator or auditor to verify these effects.

Reformed CDM using standardized project eligibility criteria reduces two important hindrances to the effectiveness of the CDM: the uncertainty associated with the CDM's benefits, and the transaction costs associated with project registration. As a result, the support provided by a reformed CDM should better incentivize activities that reduce emissions. One important challenge to this approach is that unless project types and criteria are carefully chosen, this CDM reform could allow even larger numbers of non-additional projects to register and generate credits. Determining a deration rate to apply to credits generated under a factory-based program is just another version of the puzzle of determining an accurate sectoral baseline; the uncertainties are similar. Political will is needed to implement conservative deration rates, and to restrict a reformed CDM to project types that have a high likelihood of being additional and of being enabled by the revenues from the crediting program. A second weakness of this approach is that improving the financial viability of a technology that lowers emissions may not directly or cost effectively address the barriers to that technology. Possibly addressing non-financial barriers to technology improvements directly, such as through information, analytic tools or access to financing, can be more effective and less costly than the effects of directly crediting cement factories. This is evidenced by the substantial potential to reduce emissions in the Shandong cement sector with technologies that are already cost effective.

NAMAs, since they also credit government actions, have many of the same challenges as crediting against a sectoral baseline. Additionality is even more difficult to assess than individual projects under the CDM, and for many types of NAMAs, such as capacity building and information dissemination, emissions reductions are more difficult to estimate.

A hurdle that applies to any program targeting one or several specific technologies, in any of the three categories, is that those technologies that are most likely to be effective under a sectoral crediting program are also most likely to go forward without that program. A challenge of sectoral crediting targeting specific technologies is identifying those technologies that are both likely to be effective under the program but also not likely to have been pursued on their own.

Two architectures for a sectoral crediting program might effectively support emissions reductions in the Shandong cement sector while avoiding the over-crediting of emissions reductions if designed carefully. First, is a sectoral crediting program with crediting baselines that are clearly below BAU and which involves international support in collaboration with domestic efforts to bring emissions in Shandong's cement sector down to the crediting baseline. This international support, which could be in the form of trainings, provision of factory-level analytical tools, analytical support regarding the use of blended cement and alternative fuels, financing, and other efforts listed in the background section above, is important for assuring the crediting program will result in reductions at least as large as credits generated. Even though the effects of credit generation on government action are questionable and difficult to assess, and the baseline is uncertain, the concentrated pre-crediting support effort has the potential to make substantial improvements and is the central pillar of such a program.

A second potential program would focus on a few technologies with potentials for significant emissions reductions, but which most likely would not have been pursued in the near term without focused international support. This program could be structured like a reformed CDM or could credit against a technology penetration rate. Example technologies could be alternative fuels or new low-carbon or carbon neutral cement or concrete technologies. A potential challenge to this approach in Shandong is that those technologies that have a large potential for efficiency improvements and of being successfully implemented, such as the two named, may be implemented on their own without the international program but at a slower pace. It is difficult to assess how much slower it would have be pursued in a counterfactual scenario. This approach may be difficult to adopt as a global program used in many countries and sectors, since identifying technologies that are appropriate for this approach requires grounded knowledge of the sector and of the considerations of the host country government.

I offer these two options for further study with caution. The political will is needed for them to be enacted narrowly enough and conservatively enough to avoid over-crediting. Both developing and industrialized countries have financial incentives to exaggerate the number of carbon credits from a sectoral crediting program. Industrialized countries are seeking sources of relatively inexpensive offset credits to lessen the cost of meeting their emissions targets and are receiving pressure from domestic industries to enable this. Developing countries wish to receive as many credits as possible for the actions they take.

An underlying conclusion of this study is that sectoral offsetting programs must be designed based on grounded understanding of the sector in which it is being implemented, with careful analysis of the influence a crediting program can have, and the accuracy of setting a baseline. In designing a sectoral crediting program, it is important to assess both the ability to avoid over-crediting reductions by the program, and the effectiveness of the program at reducing emissions. It is worth examining the potential for bi-lateral approaches to program development, since bi-lateral cooperation could be based and built on the understanding, relationships and trust over time that is needed for such a program to be successful. The ability to design sectoral crediting programs that are both effective at reducing emissions and avoid generating spurious credits is not yet assured.

The analysis for this chapter was performed in collaboration with researchers at the Lawrence Berkeley National Laboratory China Energy Group: Lynn Price, Stephanie Ohshita, Nan Zhou, Ali Hasanbeigi and Hongyou Lu. The opinions expressed in this chapter are my own.

Chapter 6. Conclusion

Pressure to continue and expand international offsetting

Industries in industrialized countries are putting pressure on their governments to provide options for controlling costs of compliance with GHG emissions limits. An effective offsetting program has several strong appeals. Offsetting, in principle, allows entities with emission reduction obligations to find the cheapest options globally for reducing emissions, lowering the cost of meeting those obligations, and improving the efficiency of the whole regulatory system. By putting a price on carbon emissions reductions, offsetting creates incentives for those actors who have the most grounded knowledge of emissions reduction opportunities to reduce emissions. A reformed CDM also takes advantage of existing institutions. The CDM was promoted with numerous trainings, workshops and promises, and has attracted new players and new interest into the clean energy, energy efficiency and other low-emitting industries in India and elsewhere. Researchers and policy-makers have sought ways to reform the CDM to retain these benefits while improving its environmental integrity. In this dissertation, I examine the functioning and outcomes of the current CDM, and prospects for improving those outcomes through more rigorous additionality testing and reforming or replacing the CDM with sector-scale crediting approaches.

The CDM in practice

This study on how the CDM is working in practice in the Indian power sector reveals that large numbers of projects have been able to register using poor quality arguments to demonstrate additionality. Uncertainties associated with CDM registration and CER value reduce the useful value to developers of the funds passed through the CDM by more than half, and by much more to risk averse decision-makers such as lenders. In India, home of almost a quarter of all CDM projects, there is widespread opinion among those working with the CDM that the CDM is having little influence on project development and that many non-additional projects are registering under the CDM.

There are several limitations to improving the environmental integrity of the CDM as a project-based offsetting program. First, the "investment analysis," used to show that a proposed CDM project is not financially viability with an estimate of the project's expected financial return, is considered the most reliable method for proving the additionality of a project. But choices of assumptions used in a financial assessment have at least as large an effect on the financial return of CO_2 reduction CDM projects as the effect of CERs for most projects. This allows financial assessment inputs to be chosen strategically to demonstrate that cost effective projects are not cost effective. The investment analysis is not accurate even for a best case technology – wind energy in India – for which almost all costs and revenues are documented in official contracts prior to the start of construction. The investment analysis is even more gameable for other project types.

Second, an issue widely discussed in the literature is that the CDM creates "perverse incentives" for governments to refrain from implementing policy, and for companies to increase emissions, in order to enable the generation of more credits under the CDM. Another form of perverse incentives is that crediting emissions *reductions* rather than taxing emissions can improve the profitability of high emitting and harmful projects whenever CERs generate profits rather than simply covering the costs of the abatement technology. Examples include increasing the profitability of the production of HCFCs and electricity from coal-fired power plants. Testing additionality would become more accurate if CER prices were to increase substantially, making the influence of CERs on project financial return estimates large enough to overwhelm the effect of the choice of project cost and revenue assumptions. Currently, additionality testing is much more accurate for the more potent greenhouse gases, both because of the larger financial effect of CERs, and because for some projects CER generation is the only benefit from the project activity. However, in these cases, because of the greater financial benefit from the CDM, perverse incentives are also larger, as we have seen with the HFC example.

Third, project-based offsetting must choose between two sub-optimal strategies. It can credit only projects that would not have otherwise been built for the full crediting period, causing for example, less attractive wind power sites to be built before more attractive wind sites. Or it can credit wind projects even if they would likely have been built within the crediting period of the offset project, over-crediting reductions from the project. Neither are good options.

Lastly, even if we had perfect knowledge of future emissions, offsetting at a large scale as are currently being proposed in both US and EU, while lowering the cost of mitigation today, in a number of ways, risks make future global cooperation more difficult, especially considering the very weak post-2012 targets being proposed by industrialized countries.

Just as it is difficult for a CDM validator to assess if a proposed CDM project is additional, so too is it difficult for a researcher to estimate the percentage of CDM projects that are additional. Together, these findings indicate a high likelihood that the majority of CDM projects, and a large majority of CO_2 reduction projects registered under the CDM, is non-additional.

Is there a place for offsetting in our international climate change regime?

This study on the CDM suggests that any new or continuing offsetting program should: (i) employ an alternative approach to project-by-project additionality testing that would conservatively prevent the over-crediting of emissions reductions by the program, (ii) involve minimal risk for project developers targeted by the program, (iii) be designed to avoid creating perverse incentives, and (iv) be designed to match the support needs in the specific sectors and countries in which it is being implemented.

A range of approaches for the sector-scale crediting of emissions reductions in developing countries has been proposed as a partial replacement for the CDM. These approaches fall broadly into three categories: crediting against a sectoral baseline, a reformed CDM using standardized eligibility criteria instead of project-by-project additionality testing, and credited NAMAs.

Crediting against a sectoral baseline has several challenges. A crediting baseline needs to be determined that is clearly below business-as-usual emissions to avoid over-crediting, while not being too low to be irrelevant. Business-as-usual emissions and emissions intensity projections involve uncertainty, especially in growing sectors. The magnitude of these uncertainties must be compared to the expected effect of the crediting program. If the magnitude of the uncertainties is clearly less than the effect the program will have, then it is possible to set a crediting baseline that avoids over-crediting and is still relevant. If the uncertainties are large, a deep crediting baseline is needed with substantial uncredited support to bring emissions to the crediting baseline. Regarding the effectiveness of the program, revenues from sectoral-scale crediting are even less certain than from factory-scale crediting, such as under the CDM, implying even weaker incentives generated by the program. This is because investments must first be made to bring emissions down to the crediting baseline before credits start to be generated, and actions taken by all emitters in the sector affect the total amount of credits generated by the program. Further, crediting against a sectoral baseline requires governments, instead of the private sector, to generate credits. Since governments have a range of motivations for its choice, design and enforcement of policies and programs, revenues have a weaker effect on decision-making and it is more difficult for an external program regulator or auditor to verify these effects.

A reformed CDM using standardized project eligibility criteria, would lessen the uncertainties, as well as the cost and time, associated with the CDM application process, and therefore should be more effective than the CDM at enabling new project development. However, this approach risks allowing larger numbers of non-additional projects to also more easily register under the CDM. Project types would have to be carefully chosen that have a high likelihood of being additional and of being enabled by the revenues from the crediting program.

NAMAs*,* since they also credit government action, have many of the same challenges as crediting against a sectoral baseline. Additionality is even more difficult to assess than individual projects under the CDM, and for many types of NAMAs, such as capacity building and information dissemination, emissions reductions are more difficult to estimate.

The design of a sectoral crediting program requires assessing both the effectiveness of the program in the context of the specific sectors it is applied to, and the ability to measure the program's effects. If we could measure the emissions reduced by the crediting program with a high degree of accuracy, understanding the pathways of that influence would be less important. Or if we could be confident about the influence the program will have, conservative assumptions could be applied to avoid over crediting. If both emissions reduction estimates and the actual of influence of the program are uncertain, both need to be assessed together.

In the context of the Shandong cement sector, two architectures for a sectoral crediting program stand out as having the potential to effectively support emissions reductions while avoiding the over-crediting if designed carefully. First, is a sectoral crediting program with a deep below-BAU crediting baseline, involving international support in collaboration with domestic efforts to bring emissions down to the crediting baseline. This international support, which could be in the form of trainings, provision of factory-level analytical tools, analytical support, financing, etc, is important for assuring the crediting program will result in reductions at least as large as credits generated. Even though the effects of credit generation on government action are questionable and difficult to assess, the concentrated pre-crediting support program has the potential to make substantial improvements and is the central pillar of such a program.

A second potential program would focus on a few technologies with potentials for significant emissions reductions, but which most likely would not have been pursued in the near term without focused international support. A potential challenge to this approach is identifying those technologies that have a large potential for efficiency improvements and of being successfully implemented but also have a high likelihood of not moving forward without international support. Such an assessment requires grounded knowledge of the sector and of the considerations of the host country government, difficult to carry forward under a global program in many countries and sectors.

The CDM is governed in a passive manner since the CDM governance bodies simply respond to proposals of eligible project types (methodologies) and projects submitted to them. I have argued above that it is not possible to evaluate the additionality of most CDM projects. Evaluating methodologies also involves a high level of grounded analysis. Approaches, such as the two proposed above, can be actively developed based on grounded understanding of the sectors in which they are being implemented to be likely to be effective at incentivizing new reductions and to avoid over-crediting (what Sterk 2008 calls a "top-down" approach). A bilateral approach to designing and implementing such programs might foster the relationships, understanding and trust needed to carry out an offsetting program that is effective and has environmental integrity.

These proposals require the political will to be carried out in a way that is narrow enough and conservative enough to avoid over-crediting. One sentence from an interim negotiating text from the climate change negotiations in December 2009 in Copenhagen is informative. The negotiating text, titled *Further guidance relating to the clean development mechanism* looked like this on December 10:

> "*Decides* to extend the abolishment of the payment of the registration fee and share of proceeds at issuance to clean development mechanism projects hosted in small island developing states."

And a few days later looked like this (not exact quote):

> "*Decides* to extend the abolishment of the payment of the registration fee and share of proceeds at issuance to clean development mechanism projects hosted in small island developing states, least developed countries, and countries in Africa, Latin America, southeast Asia, south Asia and central Europe."

Will a committee set up to develop targeted offsetting programs, or determine which project types in which locations are eligible, be buffered from political pressure imposed by countries to include those projects they are currently building? And then will this committee be able to take technologies off of the list as the likelihood of their additionality is periodically reassessed?

A regulatory challenge posed by offsetting is that both the buyers and the sellers gain financially from a lenient offsetting program. Industrialized countries are seeking sources of relatively inexpensive offset credits to lessen the cost of meeting their emissions targets. Developing countries wish to receive as many credits as possible for the actions they take. This confluence of interests is directly at odds with the environmental integrity of the system.

Implications for carbon trading generally

Two similarities between California's Low Carbon Fuel Standard (LCFS) and the CDM suggest that some of the hurdles to an effective offsetting program should also be considered when designing any carbon trading program. My familiarity with the LCFS comes from being involved in an initial design analysis of the program (Farrell et al 2007a, Farrell et al 2007b). The LCFS[83] was enacted under California's Global Warming Law, AB32, requiring a reduction in the carbon intensity of California's vehicle fuels by at least 10% by 2020. The LCFS allows for carbon credits to be traded among the fuel producers and importers regulated under the program.

The first similarity between the LCFS and CDM that I would like to highlight is that uncertainties in measure emissions reductions undermine the effectiveness of both programs. If uncertainties in emissions measurements from an activity are larger than the differences in emissions between that activity and its alternatives, then the program could send a market signal in the wrong direction, increasing emissions. Under the LCFS, uncertainties in measuring lifecycle emissions from biofuels, especially emissions from changes in land use, make it unclear whether biofuels increase or decrease emissions compared to gasoline (Plevin et al 2010). If the

[83] See http://www.arb.ca.gov/fuels/lcfs/lcfs.htm (Last accessed on 16 December 2010)

program uses the best estimates of lifecycle emissions from biofuels, which are lower than the emissions from gasoline, promoting biofuels under the program could lead to an increase in emission if those estimates are incorrect. If this were the case, the LCFS would put us years behind in our efforts to reduce transportation emissions, while creating a new set of interest groups, supportive industries, infrastructure, and changes in land use that can lock in biofuels production in place of activities that have more certain emissions benefits.

Second, like with the CDM and sectoral trading, the outcomes of the LCFS are affected by the structure of the sector in which it is implemented and the specific opportunities for reducing emissions in it. The LCFS is basically a biofuels policy. The current vehicle fuel producers and importers – oil refineries, and gasoline and diesel blenders and importers – constitute the majority of those regulated under the policy, and therefore are the decision makers regarding the means for complying with the regulation. These companies are not only interested in the least expensive ways to comply with GHG regulation, but they are also interested in maintaining market share. They prefer meeting the regulation with biofuels rather than other transportation fuels like electricity, since biofuels are mixed with gasoline and diesel. Instead of seeking solutions that may be most efficient for California in the long run, taking into account a range of social factors, regulated companies will choose solutions that are in their own best interest.

Simply creating a price signal is not always sufficient or productive. A carbon price functions within the limitations of our regulatory institutions, uncertainties in emissions measurements, and the context of the specific barriers to and opportunities for reducing emissions in specific sectors in specific regions. Careful analysis of this context is needed in the design of carbon trading programs and any climate policy. Program designers need to examine the specific opportunities for reducing emissions in particular sectors and how the incentives created by the carbon trading program match those opportunities compared to other policy options.

Last thoughts

The CDM creates a market for emissions permits, not emissions reductions, since it is the permits to emit that are the interest to the credit purchasers. Since typical buyers and sellers of CDM credits are not primarily concerned about the quality of the credit in terms of emissions reductions, the main actor ensuring the quality of the credits is the program regulator. Offsetting is particularly difficult to regulate because it involves measuring emissions against an inherently uncertain counterfactual scenario. Even with the best of intentions and political will, it is very difficult to design an effective offsetting program, particularly because it is difficult to assess the influence the program is having, compared to what would have happened without it.

The most certain way for industrialized countries to reduce emissions is to reduce their own emissions. Developing countries will take calls for global action to control greenhouse gas emissions more seriously if they see that industrialized countries are serious about reducing their own emissions rather than buying possibly spurious credits from abroad. More attention and research should be placed on other means to contain costs, such as a safety valve, that could possibly fund activities that aid global efforts to reducing emissions.

Before establishing an offsetting program, or a carbon trading program of any kind, confidence is needed that the program is regulatable and does the job needed, not based on theory, but on grounded cautious analysis. The analysis contained herein, grounded in the Indian power sector, with analysis in the Chinese cement sector, shows that offsetting is inherently difficult to regulate, adds uncertainty to the emissions outcomes from a cap and trade program, and unless very carefully and conservatively designed, undermines the strength of a cap and trade program.

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POLICY BRIEF: The California Air Resources Board's U.S. Forest offset protocol underestimates leakage

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SUMMARY

Analysis of projects generating 80% of total offset credits issued by the California Air Resources Board's (ARB) U.S. Forest offset protocol finds that 82% of these credits likely do not represent true emissions reductions due to the protocol's use of lenient leakage accounting methods. The U.S. Forest protocol has generated 80% of the offset credits in California's cap-and-trade program. The total quantity of emissions allowed because of this over-crediting equals approximately 80 million tons of CO_2, which is one third of the total expected effect of California's cap-and-trade program during 2021 to 2030 (ARB 2017).

Leakage, in the context of the protocol, occurs when a reduction in timber harvesting at a project site causes an increase in timber harvesting elsewhere to meet timber demand. The way ARB's protocol accounts for leakage when calculating the number of credits awarded has three serious problems.

First, the protocol uses a 20% leakage rate when a rate of 80% or higher is supported by published studies of leakage rates from reduced timber harvesting in the United States (Gan & McCarl 2007, Wear & Murray 2004). Using an unsupported low rate results in over-crediting.

Second and more importantly, there is an inconsistency between the timing of when increases in on-site carbon storage and releases due to leakage are accounted for in the protocol's methods. Most improved forest management projects assume and credit a large reduction in timber harvesting in the first year of the offset project, but deduct the associated leakage over 100 years. This outcome is physically inconsistent, as it assumes the forest would be harvested in the first year for the purpose of giving credit but assumes harvesting would be spread out over 100 years for the purpose of reducing credits to account for leakage. As a result, most forest offset projects begin in greenhouse gas debt; project landowners generate offset credits that allow emitters in California to emit more than the state's emissions cap today, in exchange for promises that their lands will continue to increase their storage of carbon over 100 years.

Third, it is unclear whether the protocol requires forestland owners to increase carbon stocks to cover leakage for 25 years or for 100 years. The ambiguity relates to whether forestland owners are required to continue to maintain on-site growth to cover the impacts of leakage after the end of the project's 25-year crediting period. If forestland owners are only required to account for leakage for 25 years, participating projects could result in no net increase in carbon storage over 100 years compared to the baseline scenario.

The below table presents the actual emissions reductions achieved by projects under the protocol under different assumptions, reported as proportions of the credits already issued. For example, the cell on the upper left (100%) represents the assumptions underlying current policy. If these

assumptions are accurate, then 100% of the credits issued represent true emissions reductions. On the other hand, if these assumptions are inaccurate, the proportion of credits that represent actual emissions reductions can be much lower. The cell on the lower right (18%) shows that if the true leakage rate is 80% and ARB chose to only credit reductions already achieved, rather than reductions expected in the future, then the real reductions achieved to date by the project add up to only 18% of the credits issued.

This analysis was performed on all credits generated by 36 compliance forest offset projects through March 23, 2019. Collectively, these projects generated offset credits equal to 97 million tons of CO_2 reductions, which is 80% of the total credits that ARB has issued under its U.S. Forest protocol.

Actual emissions reductions by U.S. Forest offset projects as percent of credits issued to date

		Expected over 100 years (ARB's current approach)	Achieved to date (Recommended approach)
If the true leakage rate is:	20%	100%	65%
	40%	99%	49%
	60%	97%	33%
	80%	96%	18%

ARB can avoid the over-crediting discussed here with a few modifications to its protocol. ARB should (1) apply a leakage rate that is 80% or higher; and (2) determine the net benefits of reduced harvesting on an annual basis by accounting for both the increased carbon storage on site and the decreased carbon storage elsewhere due to leakage at the same time. This solution is reflected in the bottom right cell of the above table (18%).

These changes are needed for the protocol to be in accordance with current law and regulation. First, given the uncertainty in true leakage rates from reduced timber harvesting within the United States, using an 80% leakage rate or higher, as is supported by the academic literature, better fulfills the conservativeness principle laid out in ARB's cap-and-trade regulations.[1] Using low rates that are not reflected in published literature is unjustified and does not fulfill the conservativeness principle. Second, generating credits today for expected net reductions over many decades into the future runs contrary to the goals of California's Global Warming Solutions Act (AB32), the 2006 law authorizing California's cap-and-trade and offsets programs. This law states that for any trade in credits using a market-based compliance mechanism, the reductions credited should occur "over the same time period" and be "equivalent in amount to any direct emission reduction required" under California's climate change law.[2]

1 " 'Conservative' means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements." California Code of Regulations, title 17, § 95802.

2 California Health & Safety Code § 38562(d)(3).

DETAILED DISCUSSION

How the U.S. Forest offset protocol works

The large majority of U.S. Forest offset projects credit forestland owners for holding more carbon on site per acre than they would have in the business-as-usual baseline scenario. Landowners must commit to maintaining those higher carbon levels for 100 years. Projects can be anywhere in the United States, and to date, approximately 20% of credits generated have been from projects in California, and 80% have been from projects elsewhere in the United States.

Most of these improved forest management projects define a business-as-usual baseline scenario that involves aggressive timber harvesting that brings on-site carbon storage close to the average per acre for forests in their region. The assumption is that these offset projects maintain higher on-site carbon stocks by reducing timber harvesting.

In the first year of an improved forest management offset project, the landowner earns offset credits for the amount of carbon on their land above the business-as-usual baseline scenario minus two factors. First, estimates of carbon released due to leakage are deducted. Second, not all loss of on-site carbon is released into the atmosphere. The protocol accounts for the portion of harvested timber that remains long-term in wood products like in houses and furniture and buried in landfills, which would be reduced if total timber harvesting is reduced by the project. Each subsequent year, the landowner is credited for any incremental increase in carbon sequestration on the participating lands as trees grow and sequester more carbon, minus the same two factors.

Leakage rate

ARB's U.S. Forest offset protocol uses a 20% leakage rate. A 20% leakage rate means that 20% of the reduction in timber harvesting caused an offset project is replaced by an increase in harvesting on other forestlands. The other 80% of the reduction is assumed not to be replaced and simply represents a decrease in timber use (i.e., fewer houses built, less paper produced, etc.)

Published literature suggests the leakage rate from reduced timber harvesting in the United States is at least 80%. Using a computable general equilibrium model, Gan & McCarl (2007) estimate that if timber production were reduced in the United States, 77% of that that timber harvesting would be displaced to other countries. Wear & Murray (2004) use econometric modeling to trace the effects of reductions in federal timber sales in the western United States in the late 1980s through the 1990s. They estimate that 84% of the reduced timber production was displaced to elsewhere within North America. Both articles underrepresent total leakage from conservation on U.S. forestlands. The former only estimates international leakage, ignoring leakage that might occur among forestland within the United States; the latter only estimates leakage in North America, ignoring leakage that could occur elsewhere. The existing academic literature on leakage rates from reduced forest harvesting does not support a 20% leakage rate. A conservative approach to addressing uncertainty in the true leakage rate would apply a leakage rate that is at least 80%.

The Climate Action Reserve, which developed the original U.S. Forest offset protocol on which ARB based its own protocol, revised its leakage rate from 20% to a sliding scale up to 80%, depending on the amount of timber harvesting performed by the offset project itself. Under this protocol, an 80% leakage rate is applied to offset projects that do not harvest at all.

The timing issue explained

As is typically done with offset projects, emissions reductions are estimated against a baseline scenario representing what would likely have happened without the offset program. Almost all ARB improved forest management offset projects define baseline scenarios that are well below their actual carbon stocks in their first year. On average across all projects analyzed, these baselines equal 70% of current carbon stocks. This means that in the first year of a project, the land owner is issued a quantity of credits equal to, on average, around 30% of the carbon stocks on their project lands, adjusted downward to account for leakage and any reduction in carbon held long-term in harvested wood products and landfills.

To create a baseline, the landowner models the carbon stocks and fluxes associated with a 100-year timber harvest scenario that reflects the harvesting expected to take place without the financial incentives from the offset program. The modeled scenario should be financially feasible and fulfill all legal and contractual obligations. In order for most projects to earn credits under the protocol, the calculated average carbon stocks in the baseline scenario over 100-years should be no less than that of the average forestlands for the project's region and forest type.

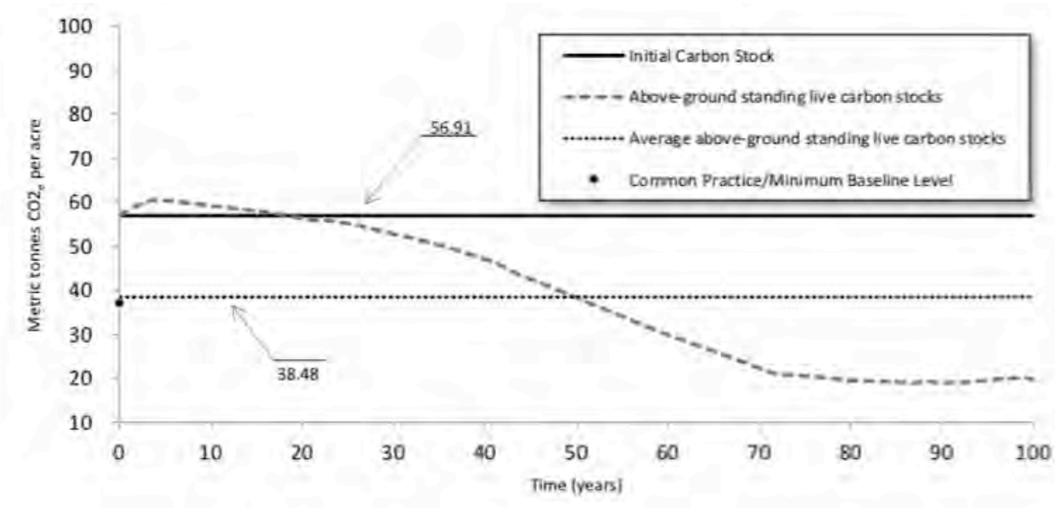
This modeled scenario is then abstracted into two key parameters used to calculate emissions reduced and credits generated by the project. Baseline on-site carbon storage and harvesting rates are assumed to equal the average values generated by the modeled scenario over 100 years. This simplified baseline is treated as equivalent, in terms of carbon accounting, to the range of financially feasible timber harvest scenarios that could have happened without the offset program. Flat average baseline values have the advantage of not requiring the landowner to calculate year-to-year increases in carbon storage against the harvest and growth cycles in one specific baseline management regime for each of 100 years. But this approach has one important disadvantage—flat average baseline values for carbon storage and harvest rates are internally contradictory and physically impossible.

The figure below presents an example of a modeled harvesting scenario used to define the baseline for one large offset project – ACR360, a half million acre project in southern Alaska. The curved dotted line is the modeled business-as-usual scenario for above-ground standing live carbon stocks. The straight dotted line is the baseline used to generate credits, which is the average above-ground standing live carbon stock in the 100-year modeled scenario. The solid line is the actual carbon storage on the project lands at the start of the project.

This simplified baseline scenario suggests that, if the project were not earning offset credits, its lands would be harvested to baseline levels in year 1 and maintained at those carbon stocking levels for 100 years. However, contradicting this assumption, the baseline also assumes that a constant quantity of timber is harvested each year over the project life, equal to the average rate over the 100-year modeled scenario. This second assumption is used to calculate leakage.

These two assumptions are contradictory because it is not possible for both carbon storage and harvesting to simultaneously remain at their respective average values over the project life. Carbon storage and harvesting rates are correlated with one another, and inextricably tied to the actual net growth rate of the project forest. If carbon storage is assumed to drop to the baseline in year 1, that would happen because of a large amount of timber harvesting. If the harvesting rate is assumed to be constant over 100 years, however, then the carbon storage on the land will also decrease slowly, rather than abruptly in year 1. By mixing these two assumptions into a physically impossible baseline scenario, the protocol maximizes credits generated without reflecting the actual rate at which emissions to the atmosphere are avoided. The protocol calculates gains in carbon against the baseline using the first assumption, and losses in carbon from leakage using the second assumption. As a result, credit generation is frontloaded, and landowners need to continue to increase net carbon storage for decades to make up for the leakage effects associated the reduced harvesting credited at the start of the projects.

Baseline carbon stocks for Finite Carbon – Ahtna Native Improved Forest Management offset project



From: ACR360 "Finite Carbon – Ahtna Native Alaskan IFM" Version 1.3, Attachments G and H: Baseline Carbon Stocks, Submittal Date: 1/19/2018

This over-crediting allows emitters in California to emit more than the state's emissions cap today in exchange for promises of forest carbon sequestration over 100 years to cover leakage from the start of the project. This is problematic for several reasons. First, emissions today are not equivalent to reductions decades from now given the urgency of climate change mitigation to avoid tipping points. California is designing its cap-and-trade and offset programs as models for other jurisdictions. If California exports a model that trades emissions today with reductions decades from now, California would promote a form of climate policy that fails to reduce emissions in these immediate critical years. Second, these promises can be difficult to keep since productivity slows in ageing forests (Gray et al 2016) and as forests respond to a warming climate. On project lands with less harvesting, fewer older trees will be replaced with younger trees, and the average tree age will increase over the 100 years of the project.

ACR360 generated close to 15 million offset credits in its first year, equal to more than 60% of the expected average annual effect of California's cap-and-trade program on emissions during 2021-2030.

The 25 year versus 100 year issue explained

If forestland owners are required to increase carbon to cover leakage for 100 years, then there would be no over-crediting over 100 years of the project. Over-crediting in the early years of the project would slowly be compensated as leakage is deducted each year for the project life.

However, it is unclear whether the protocol requires forestland owners to account for the emissions from leakage for 25 or for 100 years. The crediting period of a U.S. Forest offset project is 25 years. After the end of each 25-year crediting period, landowners can choose to renew their offset project for another 25 years but are not required to do so. For each year of a crediting period, landowners must report the net impact of the project on emissions taking into account any change in on-site carbon storage, and any releases due to leakage or reductions in carbon held long-term in harvested wood products and in landfills. If the net impact of the project in any year is negative, a *reversal* is understood to have occurred. The carbon reductions that were previously credited and later released must be replaced with additional procurement of allowance or offset credits.

How a reversal is defined after the last year of crediting is unclear in the protocol. Following the last year of crediting, forestland owners are required to maintain the credited on-site carbon storage for another 100 years. It is unclear if they are also required to ensure their forestland continues to grow to cover off-site releases due to leakage and due to reductions in carbon held long-term in harvested wood projects and landfills.

If forestland owners are only required to account for leakage for 25 years, crediting for reduced harvesting in the first year of the project will be awarded in full, while potentially, as low as only 1% of the leakage associated with that reduced harvest is deducted each year for only 25 years. It would be possible for participating projects to result in a net decrease in carbon storage over 100 years compared to the baseline.[3]

Methods

Landowners report how they calculate their requested credit issuance in Offset Project Data Reports (OPDRs) based on instructions laid out in the protocol. These reports are made public through the offset registries. We reproduce these calculations for all credits issued to 36 projects as of March 23, 2019. We use data provided by the landowner in their OPDRs and supplemental materials, and adjust the projects' assumptions for leakage and the timing of harvesting in the baseline to investigate the quantity of over-crediting.

Adjusted leakage rate

Using data reported in the OPDRs, we reproduce the calculations of leakage (also called *secondary effects*), carbon in harvested wood products and landfills (HWP&L), and total reductions achieved using leakage rates of 40%, 60%, and 80% instead of 20%.

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[3] Please see public comments submitted to ARB on May 10, 2018, *Comments on proposed cap-and-trade regulatory amendments*, for a more detailed discussion of this need to clarify and revise how the protocol defines a reversal after the last year of credit issuance, found at http://bhaya.berkeley.edu.

Adjusted timing of baseline harvesting

We recalculate the credits that would have been generated if the protocol's leakage calculations matched its assumption that timber is harvested in year 1 of the baseline scenario to bring carbon storage down to baseline levels, and continues to be harvested at smaller rates needed to maintain the baseline carbon storage level for one hundred years.

We do this in the following manner:

First, the baseline harvesting level prior to delivery to the mill (PDM) in the first year of the project is calculated as the difference between standing live carbon in the project compared to the baseline.

Second, we calculate the baseline carbon in trees harvested in years 2 to 100 so that the sum of the baseline PDM over 100 years is the same as the sum using ARB's current methods. We calculate the baseline PDM in years 2 through 100 (99 years) as:

$PDM_{\text{annual after year 1}} = (PDM_{\text{total}} - PDM_{\text{year 1}}) / 99$

Third, we recalculate the carbon in baseline HWP&L in a similar manner, by:
a) using the ratio of HWP&L to PDM in year 1 of the baseline in the OPDR to recalculate carbon in HWP&L in year 1 of the baseline for the revised PDM value;
b) calculating carbon in HWP&L in years 2 through 100 using the same process as for timber harvesting, so that the sum of carbon in HWP&L over 100 years of the baseline is the same in our estimates as it is in ARB's current estimates over the project life;

Fourth, we recalculate emissions reductions from the project using these revised leakage and carbon in HWP&L figures, and otherwise following the methods defined by the protocol.

When baseline or project PDM figures are missing from any of the OPDRs, we calculate the missing PDMs mathematically from other reported figures when possible, and apply the following assumptions when needed:

- The ratios of carbon in HWP&L to PDM remain the same across reporting periods.
- When the first reporting period does not equal exactly one year, the PDM in the first year is a prorated amount, reflecting what most projects with at least two reporting periods have done.
- The ratio of carbon in HWP&L to PDM is the same in both the baseline and project scenarios.

Other than the changes and assumptions described above, we repeat the methods used in the OPDRs to re-estimate emissions reduced and credits generated.

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Managing uncertainty in carbon offsets: insights from California's standardized approach

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RESEARCH ARTICLE

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Managing uncertainty in carbon offsets: insights from California's standardized approach

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ABSTRACT
Carbon offsets allow greenhouse gas emitters to comply with an emissions cap by paying others outside of the capped sectors to reduce emissions. The first major carbon offset programme, the United Nations' Clean Development Mechanism (CDM), has been criticized for generating a large number of credits from projects that do not actually reduce emissions. Following the controversial CDM experience, California pioneered a second-generation compliance offset programme that shifts the focus of quality control from assessments of individual projects to the development of offset protocols, which define project type-specific eligibility criteria and methods for estimating emissions reductions. We assess the ability of California's 'standardized approach' to mitigate the risk of over-crediting greenhouse gas reductions by reviewing the development of two California offset protocols – Mine Methane Capture and Rice Cultivation. We examine the regulator's treatment of three sources of over-crediting under the CDM: non-additional projects, inflated counterfactual baseline scenarios, and perverse incentives that inadvertently increase emissions. We find that the standardized approach offers the ability to reduce, but not eliminate, the risk of over-crediting. This requires careful protocol-scale analysis, conservative methods for estimating reductions, ongoing monitoring of programme outcomes, and restricting participation to project types with manageable levels of uncertainty in emission reductions. However, several of these elements are missing from California's regime, and even best practices result in significant uncertainty in true emission reductions. Relying on carbon offsets to lower compliance costs risks lessening total emission reductions and increases uncertainty in whether an emissions target has been met.

Key policy insights

- Substantial and ongoing oversight by offset programme administrators is needed to contain uncertainty and avoid over-crediting.
- California's Mine Methane Capture Protocol may have influenced federal decisions not to regulate methane emissions from coal mines on federally-owned lands.
- Government priorities and methodological choices drive outcomes in carbon pricing policies with large offset programmes, contrary to the common perception that these policies delegate decision-making to private actors.
- Offsets are better understood as a way for regulated emitters to invest in an incentive programme that achieves difficult-to-estimate emission reductions, than as accurately quantified tons of reductions.

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1. Introduction

Carbon offsets allow greenhouse gas (GHG) emitters regulated under a cap-and-trade programme to pay for emission reductions outside of capped sectors in lieu of reducing their own emissions or acquiring allowances from other regulated parties. Offsets have been widely used in cap-and-trade programmes to lower compliance costs and support reductions in regions and sectors outside of the cap (ARB, 2010; Bushnell, 2012). During the first commitment period of the Kyoto Protocol (2008–2012), for example, the European Union Emissions Trading Scheme utilized offset credits equal to 11% of covered emissions (Ellerman et al., 2014, 2015). In the first eight years of California's carbon market, regulated parties can submit offsets for up to 8% of their total emissions, or about 79% of the total reductions the California Air Resources Board (ARB) expects from the state's capped sectors (Haya, 2013).

Although carbon offsets are widely used in cap-and-trade programmes, they have also been controversial. Empirical studies of the Kyoto Protocol's offset programme, the Clean Development Mechanism (CDM), find that many CDM projects received credits far in excess of the additional reductions they achieved. These studies point to three principal sources of over-crediting. First, the CDM credited large numbers of 'non-additional' projects – projects that would have happened on their own, independent of the income from offset credits (Aldy & Stavins, 2012; Cames et al., 2016; Haya, 2009; He & Morse, 2013; Wara, 2008). This occurred, in part, because of difficulty evaluating project developers' individual claims that they would not have moved forward with their proposed offset projects without the offset programme (Haya, 2010). Second, the need to estimate emission reductions against an unobservable, and therefore uncertain, counterfactual baseline also allowed project developers to apply high emissions baseline scenarios, often resulting in inflated reduction estimates (Lazarus & Chandler, 2011). Third, offset programmes created perverse financial incentives that resulted in inefficient or harmful actions that physically increased emissions. For example, profits generated by offset sales from hydrofluorocarbon (HFC) destruction projects were large enough to create an incentive for refrigerant producers to increase production and reduce production efficiency in order to generate more HFC by-product that could be destroyed to generate offset credits (Schneider & Kollmuss, 2015; Wara, 2008). Considering the broader political effects of an offset protocol, carbon offsets can also create an incentive for governments to delay enactment of policies requiring reductions from sectors profiting from offset credits, since reductions are no longer eligible for offset revenue once they are required by law (Figueres, 2006; He & Morse, 2013).

These three potential sources of over-crediting – non-additional projects, inflated counterfactual baselines, and perverse incentives – create significant challenges for climate regulators. Proposed solutions include excluding project types that risk generating large quantities of false credits (Cames et al., 2016; Erickson et al., 2014; Thamo & Pannell, 2015); including only project types unlikely to go forward without the added incentive from offsets (Claassen et al., 2014); counterbalancing over-crediting with under-crediting via discount factors, conservative baselines, or shorter crediting periods (Bento et al., 2016; Erickson et al., 2014); using programme-, policy-, or sector-scale offset crediting (Lewis, 2010; van Benthem & Kerr, 2013); and replacing project-by-project additionality testing and baseline determination with standardized protocol-level criteria (Government of Italy, 2014; UNFCCC, 2014).

California took the latter approach, launching a second-generation compliance offset programme that concentrates quality evaluation at the protocol level, commonly called a 'standardized approach'. This approach was first implemented by the Climate Action Reserve (CAR), a state-chartered voluntary offset developer; in parallel, several CDM methodologies were modified to include a standardized approach to additionality testing (Hayashi & Michaelowa, 2013). Under California's standardized approach, each offset protocol specifies a set of eligibility criteria. Every project meeting these criteria is deemed to fulfil the additionality requirement and is allowed to generate credits according to the protocol's standardized methodology for calculating baseline emissions and net emission reductions. Under this paradigm, offset credit quality is managed for the portfolio of offset projects as a whole, rather than for each participating project individually. A regulator can address over-crediting from the participation of non-additional projects that meet a protocol's eligibility requirements by assessing the entire pool of credits a protocol generates. So long as the total number of credits awarded to non-additional projects is counterbalanced by conservative[1] accounting methods, such as stringent baselines (Bento et al., 2016), that reduce the estimated emission reductions and number of credits awarded, the protocol-level additionality standard is satisfied. This approach differs from previous offset programmes, which test additionality for each proposed project, allow more flexibility for project developers to customize baseline and emissions reduction methods, and accommodate a much wider set of project types.

The standardized approach is expected to lower transaction costs (Hayashi & Michaelowa, 2013; Spalding-Fecher & Michaelowa, 2013) and increase consistency (Schneider et al., 2012) for participating project developers that no longer need to demonstrate the additionality of their individual projects or to defend project baselines. It is also expected to better enable offset programme administrators to avoid over-crediting by substituting protocol-scale standards for evaluations of project-specific additionality and baseline claims that were largely ineffective (Haya, 2010), while also facilitating public stakeholder participation in programme decisions (Haya et al., 2016). If protocol-level eligibility criteria are too lenient, however, a standardized approach could lead to large-scale over-crediting (Bushnell, 2011; Cames et al., 2016; Haya, 2010; Hayashi & Michaelowa, 2013; Spalding-Fecher & Michaelowa, 2013) while potentially prohibiting some truly additional projects from participating (Schneider et al., 2012). Similarly, being overly conservative could backfire if the benefits of participation are made so small that predominantly eligible non-additional projects participate (Kollmuss & Lazarus, 2011; Thamo & Pannell, 2015).

In this paper, we explore whether and how California's standardized approach to carbon offset protocol design can address the risk of over-crediting, focusing on the three principal sources of over-crediting observed under the CDM: (1) non-additional projects, (2) inflated baseline emissions, and (3) perverse incentives. Our analysis focuses on ARB's process of developing two California offset protocols – Mine Methane Capture (MMC) and Rice Cultivation – and is rooted in our experiences during 2013 through 2015 as a team of researchers participating in the technical working groups established by California to support protocol development (see Haya et al., 2016). We draw on our observations of the protocol development process, discussions with researchers and practitioners, and our own quantitative and qualitative analyses. Our study is exploratory, using mixed methods and our respective disciplinary and topical training, which includes law, economics, biogeochemistry, engineering, geography, and energy resources, to assess the risk of over-crediting and strategies for avoiding that risk under the two protocols. Over-crediting is understood to occur when the quantity of credits generated by the set of projects under a protocol as a whole exceeds the actual effect of the protocol on emissions, taking into account effects outside of individual project boundaries. Our intent is to analyze the risk of over-crediting without judging the acceptability of that risk against offsets' expected cost reductions and political benefits.

The goals of this paper are to examine (1) if the standardized approach can be used to avoid substantial over-crediting, (2) the types of analysis and design decisions needed to do so, (3) how California's specific protocol design and review process can be improved, and (4) what California's experience tells us about the risks and opportunities of carbon offset programmes in general. Our results have important implications for climate policy design, especially as more jurisdictions and international bodies consider implementing offset programmes.

2. Background

2.1. California's cap-and-trade programme

California's climate laws, known as AB 32 (2006) and SB 32 (2016), require the state to reduce its GHG emissions to 1990 levels by 2020 and to 40% below 1990 levels by 2030. ARB was tasked with developing policy to achieve the state's GHG targets and eventually adopted a suite of policies that include direct regulatory instruments and an economy-wide cap-and-trade programme (Wara, 2014).

The cap-and-trade programme covers approximately 75% of the state's GHG emissions (ARB, 2019a, 2019b) – about 450 large emitters in the state's highest emitting sectors: electricity, industrial, transportation fuels, and natural gas (ARB, 2015b). Covered emitters must submit compliance instruments (allowances and offsets) equal to their reported GHG emissions. ARB describes cap-and-trade as a 'backstop' policy, while traditional regulations do most of the work needed to meet California's 2020 target (ARB, 2014; Bang et al., 2017). Cap-and-trade has likely played only a modest role in driving emissions reductions due to the oversupply of compliance instruments on the market (Legislative Analyst's Office, 2017). Going forward, however, ARB expects cap-and-trade to deliver approximately 38% of the cumulative emission reductions projected to be necessary over the period 2021 through 2030, and fully 47% of the annual reductions needed to achieve the state's 2030 climate target (ARB, 2017: Figure 7).

2.2. California's offset programme

ARB's cap-and-trade regulations limit the use of offsets to 8% of each regulated emitter's total emissions each year through 2020.[2] Thus, if all emitters fully exploit this limit, their total emissions would increase to approximately 8% above the cap, with offsets crediting reductions in sectors outside the cap in an amount that is equal to that increase. In the market's post-2020 period, the offsets limit will be reduced to 4% of capped emissions from 2021 to 25 and 6% from 2026 to 30. Companies submitted offset credits equal to 4.4% of their emissions in the market's first compliance period (2013–14) (ARB, 2015a) and 6.4% of their emissions in the second (2015–17) (ARB, 2018). Many regulated companies would prefer to increase their use of offsets because these are expected to be less expensive than reductions under the cap (Borenstein et al., 2018).

Although the offset limits might seem small compared to total emissions, they constitute a large share of the reductions required under cap-and-trade. ARB forecasted that cumulative reductions required in capped sectors through to 2020 will be approximately 10% of those sectors' business-as-usual emissions (Haya, 2013). The 8% offsets limit therefore represents approximately 80% of the mitigation required in capped sectors through to 2020. From 2021 to 2030, the lower offset limits are equivalent to 20% of total expected cumulative statewide mitigation requirements, and over half of the reductions expected to be achieved by the cap-and-trade programme itself (Haya, 2018). As a result, the environmental effectiveness of the cap-and-trade programme will likely depend on the quality of the carbon offset programme.

Each California offset protocol defines a specific set of activities eligible to generate offset credits and includes detailed methodologies for estimating the emissions reduced (and therefore credits generated) by each participating project. California's first four offset protocols were largely based on protocols developed for the voluntary market by CAR: US Forest, Livestock, Ozone Depleting Substances (ODS), and Urban Forest. In 2013, ARB started developing two more offset protocols: MMC and Rice Cultivation. Like the four original protocols, both were largely based on voluntary CAR protocols; however, the final MMC and Rice Cultivation protocols were developed through a multi-year stakeholder process that involved technical working groups in which the authors participated (Haya et al., 2016).

2.2.1. Mine methane capture (MMC) projects protocol

Many coal deposits contain methane, a potent GHG that can be released into the atmosphere during or after coal mining. The MMC Protocol, adopted in April 2014, credits the destruction of methane that would otherwise have been released into the atmosphere from active underground and surface coal mines, abandoned underground coal mines, and trona mines[3] in the United States. Creditable methane destruction methods include (1) flaring from drainage wells, which tend to have high methane concentrations; (2) methane capture from drainage wells for use, including through pipeline injection, fuel for vehicles, and on-site electricity generation; and (3) oxidizing methane from ventilation systems, which tend to have low methane concentrations.

2.2.2. Rice cultivation projects protocol

Rice cultivation is an important source of anthropogenic methane and nitrous oxide emissions. Rice is grown in flooded fields where anaerobic decomposition of organic material produces methane and anaerobic denitrification produces nitrous oxide. The Rice Cultivation Protocol, adopted in June 2015, credits reductions in methane emissions resulting from shorter flooding periods achieved by (1) seeding fields under dry, rather than wet, conditions; (2) draining fields earlier in the autumn; or (3) drying fields periodically during the summer cultivation period. The protocol uses the DeNitrification-DeComposition (DNDC) process-based biogeochemical model (University of New Hampshire, 2012) to estimate net CO_2, nitrous oxide, and methane emissions from changing rice cultivation practices in the United States, based on field-specific crop management, fertilizer, field management, and weather parameters.

3. Analysis

Our qualitative and quantitative analysis of ARB's MMC and Rice Cultivation protocol design processes focuses on whether and how the standardized approach can be used to avoid substantial over-crediting from three environmental integrity challenges: (1) additionality: would the credited reductions have happened without offsets, (2) baseline emissions: more broadly, does the protocol conservatively estimate the emissions that would occur without offsets, and (3) perverse incentives: do the incentives created by offsets inadvertently increase emissions.

3.1. Additionality

Because an offset credit enables its holder to emit one extra ton above a cap-and-trade programme's cap in exchange for one ton reduced or sequestered outside of the capped sectors, the offset project must cause (and not merely be coincident with) emission reductions. California's climate law, AB 32, codifies this additionality standard by requiring that reductions from market-based compliance mechanisms be 'in addition to … any other greenhouse gas emission reduction that otherwise would occur'.[4] As described above, a major challenge of protocol-level additionality assessments is that even non-additional projects can generate offset credits if they meet eligibility criteria.

ARB has chosen to operationalize its protocol-level additionality requirement with a 'common practice' assessment. Under this approach, a project type is considered additional if it is not common practice, a determination that is based on 'staff's best estimate of the percent of the technology or mitigation in use' for the relevant sector (ARB, 2013a, pp. 7–8). Here we analyze ARB's application of its common practice assessment to methane capture at abandoned coal mines under the MMC Protocol, illustrating how different applications can significantly alter offset credit quality.

After ceasing operation, gassy underground coal mines continue to emit methane (US EPA, 2008). At the time of MMC Protocol development, only 38 (6%) of the approximately 645 abandoned gassy underground mines in the United States engaged in methane capture (Ruby Canyon Engineering, 2013). An early draft of the protocol concluded: 'from the population of … abandoned underground mines in the United States, few currently capture and destroy mine methane' and therefore 'abandoned underground mine methane recovery activities are deemed additional' (ARB, 2013b, p. 7). This initial approach to evaluating common practice risked generating a large proportion of credits from non-additional activities for four reasons.

First, ARB initially focused its common practice assessment on the number of mines, rather than the quantity of emissions. The difference matters because methane concentrations vary substantially across mines. Even though only 6% of abandoned mines captured methane in 2011, these projects captured approximately 33% of total methane released from abandoned mines in the United States (US EPA, 2013b).

Second, methane capture is financially or technologically infeasible at most of the 645 abandoned mines in the United States. One study found that additional methane capture is feasible at only 67 US abandoned mines (Ruby Canyon Engineering, 2013). Based on this study, abandoned mines already captured approximately half of total feasibly captured methane emissions. Thus, if ARB assessed common practice based on the quantity of *feasible* methane capture already occurring, it would have determined that abandoned mine methane capture is already common practice.

Third, an aggregated, sector-wide assessment may fail to identify sub-categories of projects that are common. For example, all mines abandoned between 1993 and 2012 that captured methane when they were active continued to capture methane after abandonment (Collings, 2013, US EPA, 2016b). If past rates of coal mine abandonment and abandoned mine methane capture development continue – and all abandoned mines are eligible to generate credits – business-as-usual methane capture could generate credits equal to 44–54% of total feasible new methane capture potential at the current pool of abandoned mines (see Supplemental Materials, Table SM-2). Thus, the quantity of non-additional credits generated from abandoned mines would likely exceed – possibly by a large amount – the total credits generated from truly additional abandoned mine methane projects.

Fourth, even if ARB had amended its common practice analysis to focus on quantity of emissions instead of numbers of mines, and on mines where methane capture is technically and financially feasible, while categorically excluding mines that captured methane when they were active, one more step would still be needed to avoid the risk of substantial non-additional crediting. During 1993–2012, new methane capture systems were built at 30 abandoned coal mines that did not capture methane when they were active. If this implementation rate continues unchanged, new business-as-usual abandoned mine methane capture projects at similar mines could generate non-additional credits equal to 8–16% of total feasible methane capture (see Supplemental Materials, Table SM-2). Given uncertainty in the effect of the protocol on new project development, non-additional projects could still make up a large share of credit generation.

In its final protocol, ARB did explicitly exclude abandoned mines that captured methane when they were active on the grounds that methane capture at this particular sub-category of mines is already common practice. ARB's decision to assess a common practice at a higher resolution avoided a significant risk of non-additional crediting. But as we show, even with this exclusion, the risk of substantial over-crediting remains.

To contain this risk of over-crediting, ARB could conduct a market analysis to assess the likely business-as-usual deployment of mine methane capture systems going forward and the expected effect of the protocol on new project development. ARB could then reduce the credits expected to be generated from the total portfolio of abandoned mine methane capture systems by the amount of anticipated non-additional crediting that is eligible to generate credits. This could be done using conservative methods to estimate emissions reduced by projects participating under the protocol (Bento et al., 2016; Erickson et al., 2014). While this approach risks weakening the effectiveness of the protocols in incentivizing emissions reductions (van Benthem & Kerr, 2013), it is needed to avoid over-crediting. If total under-crediting from the discounting of additional credits equals total over-crediting from participating non-additional projects, then the credits generated would equal the net impact of the protocol on emissions and all credits could be considered additional.

The MMC protocol example explores the implications of methodological choices for conducting a common practice analysis on the ability to avoid significant over-crediting from the participation of non-additional projects. It also illustrates the potential high levels of uncertainty in additionality assessments of project types that are already being implemented without the aid of carbon offsets. In our view, uncertainty in both business-as-usual development of eligible abandoned mine methane capture systems and the expected effect of the protocol on new development is so large that the share of credits from non-additional projects could be anything from 0 to 100%. ARB might be able to reduce this uncertainty with more market and financial analysis, but that would require detailed industry expertise that may be out of reach to programme regulators, in a sector with minimal relevance to the agency's core jurisdiction.

3.2. Baseline emissions

Establishing additionality is one aspect of a broader challenge – estimating baseline emissions (emissions that would occur in the absence of the offset incentive). Project emissions can be observed and independently validated, but the baseline scenario never occurs. As a result, baseline emissions are inherently deeply uncertain. This section explores how the standardized approach can be used to avoid over-crediting given uncertainty in baseline emissions.

3.2.1. Scientific uncertainty in the baseline: abandoned mines

Estimating baseline emissions in the MMC Protocol is difficult because methane capture devices can extract more methane than would have escaped to the atmosphere in the absence of the device (ARB, 2013b). Because these extra emissions would not occur in the absence of MMC projects, the quantity of methane captured by offset projects cannot be used as a baseline. Instead, the protocol estimates baseline emissions from abandoned mines using a hyperbolic emission rate decline curve model (US EPA, 2016c). Project developers can input either default coefficients or measured site-specific values into the model. This choice can lead to over-crediting if developers make methodological choices to generation more credits.

For projects at mines that never drained methane when active and use default parameter values, ARB discounts the number of credits awarded by 20% to account for possible discrepancies between the default and the actual project-specific baseline. ARB's decision to apply a discount factor addresses a known uncertainty, but the specific discount factor – 20% – reflects the agency's subjective expert judgment, based on stakeholder feedback. The environmental integrity of offsets depends on whether this subjective value is sufficiently conservative to avoid over-crediting. Without a more explicit analysis of uncertainty associated with baseline estimates, possibly including audits of specific projects, it is difficult to evaluate whether this discount factor is appropriate.

3.2.2. Behavioural uncertainty in the baseline: rice farmer practice

The Rice Cultivation Protocol defines baseline cultivation practices – such as when fields are drained or how much fertilizer is applied – in two ways, depending on the project location. Both methods make assumptions about farmers' cultivation choices. For projects in the Mid-South of the United States, baseline emissions are projected using the widely-used DD50 rice management model developed to aid farmers in cultivation decisions (University of Arkansas, 2018). For projects in California, however, baseline emissions are defined based on what each farmer reports about past cultivation practices, rather than model projections.

Both approaches to baseline setting are uncertain and vulnerable to over-crediting. Modelled common farmer practice in the Mid-South does not necessarily predict any single farmer's practice. For example, farmers who were already draining fields earlier than the DD50 model recommends can earn credit for early drainage without changing their practices. Similarly, in California, simple averages of a specific farmer's past cultivation practice are not necessarily good predictors of future practice because cultivation decisions reflect each season's specific conditions. It is also common for farmers to experiment with new practices to reduce risk, improve yield, lower costs, respond to market prices, or achieve other goals like water conservation. Furthermore, it can be difficult for third party auditors to verify past farmer practice, potentially allowing California rice farmers to exaggerate the emissions associated with past practice to earn more credits.

In light of these challenges, ARB decided to test alternative methods at different project sites that third-party verifiers can use to verify baseline emissions to explore their feasibility and effectiveness.

While the standardized approach reduces information asymmetry by moving away from project-by-project determinations of additionality and baselines, it also increases the risk of adverse selection, since projects that already meet the eligibility criteria or exceed the standardized baseline can earn credits for business-as-usual activity.

3.3. Perverse incentives

A third major over-crediting risk is that offsets can create perverse financial incentives that inadvertently increase emissions, such as by increasing the profits of high-emitting activities, creating disincentives to enact legally binding regulations, and inducing business-as-usual mitigation projects to shift their activities to earn offset credits.

3.3.1. Increasing profits: coal mining

The US coal industry has been in decline in recent years (US EIA, 2016, 2019b). In a shrinking market for coal production, increased profits from offset credit sales might extend the lives of otherwise uncompetitive coal mines, leading to increased emissions from burning the additionally produced coal.

To assess the scale of this risk, we analyze potential profits from implementing mine methane capture projects at the eight active underground coal mines in the United States that the Environmental Protection Agency (EPA) identified as having methane drainage wells that vented the majority of drainage methane to the atmosphere and that did not already have pipeline injection systems (US EPA, 2016b). These coal mines are prime candidates for mine methane capture systems because of their large and high-concentration methane releases (US EPA, 2013a), and because capture is more economically favourable when mines are active.

We used EPA's Coal Mine Methane Project Cash Flow Model version 3.0 (US EPA, 2016a), and 2012 data for coal production (Fiscor, 2013), coal sales prices (US EIA, 2013), and methane releases (US EPA, 2016b) for each of the eight mines (see Supplemental Materials, Table SM-3). Our analysis indicates that ARB's MMC Protocol could increase coal mining profits by as much as 17% if offset credits sell at \$10 per tCO_2e (lower than prevailing allowance prices in California), with a coal mass production-weighted average increase in mining profits of 3% across the eight mines analyzed. At \$50 per tCO_2e – a price for carbon credits that is not imminent but is plausible in coming years (Borenstein et al., 2017) – mine profits could more than double at some mines, with a production-weighted average increase of 23% across the eight mines analyzed. Although the size of the effect is uncertain, there is a clear risk that the financial incentive created by the MMC protocol will result in increases in emissions from mines that produce longer than they otherwise would have.

3.3.2. Increasing profits: inducing a switch from corn to rice production

By providing an additional source of revenue to rice farmers, the Rice Cultivation Protocol could shift the relative profitability of rice in comparison to other crops, leading to crop switching with emissions impacts. In areas of the US Mid-South, farmers commonly shift between rice and corn production (Jekanowski & Vocke, 2013). However, rice production is about four times more emissions-intensive than corn production in those areas (Nalley et al., 2011). Corresponding changes in Arkansas crop prices and acreage since 2005 indicate that shifts between rice and corn in Arkansas are correlated with changes in relative crop prices (data from USDA 2013a, USDA 2013b). Assuming historical elasticities between prices and acreage, offset profits of \$10 per tCO_2e could induce a shift of 1–2% of corn acreage to rice production. If only a fraction of this crop switching were to occur, the emissions benefits of the protocol would be weakened by 9–41% (see Supplemental Materials). The potential emission increases associated with such offset-induced crop switching are material enough to warrant monitoring if offset prices increase and Rice Cultivation Protocol projects start to be implemented. This example highlights the potential for carbon offsets to affect emissions by changing the relative profitability of competing products.

3.3.3. Weakening or delaying climate regulation

Carbon offsets can also exert perverse effects on the political economy of climate policy development. By definition, any emission reductions that are required by law are non-additional and therefore ineligible to earn offset credits. As a result, carbon offset revenues create an added incentive for those benefiting from offset projects to advocate against legally binding regulations that apply to their activities.

These concerns have manifested themselves in California's carbon offset regime, which may have affected federal climate policy decisions during the Obama Administration. In April 2014, the Bureau of Land Management (BLM) issued an Advance Notice of Proposed Rulemaking (ANPRM) on reducing emissions of waste methane from active underground mines on federal lands (Bureau of Land Management, 2014). The ANPRM contemplated various options, including mandating or creating incentives for capture. However, mandatory regulations would preclude affected mines from earning offset credits through California's MMC Protocol. BLM issued a final rule limiting methane emissions from oil and gas operations on federal lands effective January 2017 (Bureau of Land Management, 2016) without mention of methane from coal mines.

Preliminary evidence suggests, though does not conclusively establish, that incentives from California's MMC Protocol may have contributed to BLM's decision not to require methane capture at coal mines on federal lands. At the 2014 US Coal Mine Methane conference held by the US EPA in Pittsburgh, Pennsylvania, BLM representatives stated during their presentation that BLM was taking California's MMC Protocol into account in deciding whether and how to regulate or incentivize the capture of waste methane from active underground coal mines on federal lands (Leverette & LaSage, 2014). The representatives further indicated to conference participants that BLM intended to support California's offset programme. It is not possible to know what BLM action (and by extension, methane mitigation activity) would have occurred in the absence of California's offset programme. Nevertheless, it is notable that the BLM subsequently opted to regulate methane emissions from oil and gas operations but not from coal mines, and that the BLM representative conveyed that the California protocol was part of the federal agency's deliberations. We believe this example illustrates the potential for carbon offset programmes to delay or weaken legally binding climate regulations.

3.3.4. Accidentally increasing emissions through eligibility restrictions

To avoid over-crediting, offset protocols using the standardized approach generally exclude project types likely to result in substantial non-additional crediting. Though necessary, such exclusions can lead to unintended effects. For example, since pipeline injection is considered common practice and is thus ineligible under California's offset programme, but flaring remains eligible at qualifying drainage wells, mine operators face a choice. If they sell captured methane into the natural gas pipeline network, they receive the market value of methane's use as a fuel. Alternatively, mine operators could choose to flare the captured methane to sell offset credits.

Figure 1 illustrates the relative revenues from pipeline injection versus flaring for different combinations of carbon and natural gas prices. Given current and likely future carbon market prices (Borenstein et al., 2017), flaring captured methane for carbon credits is likely to be much more valuable than the productive use of

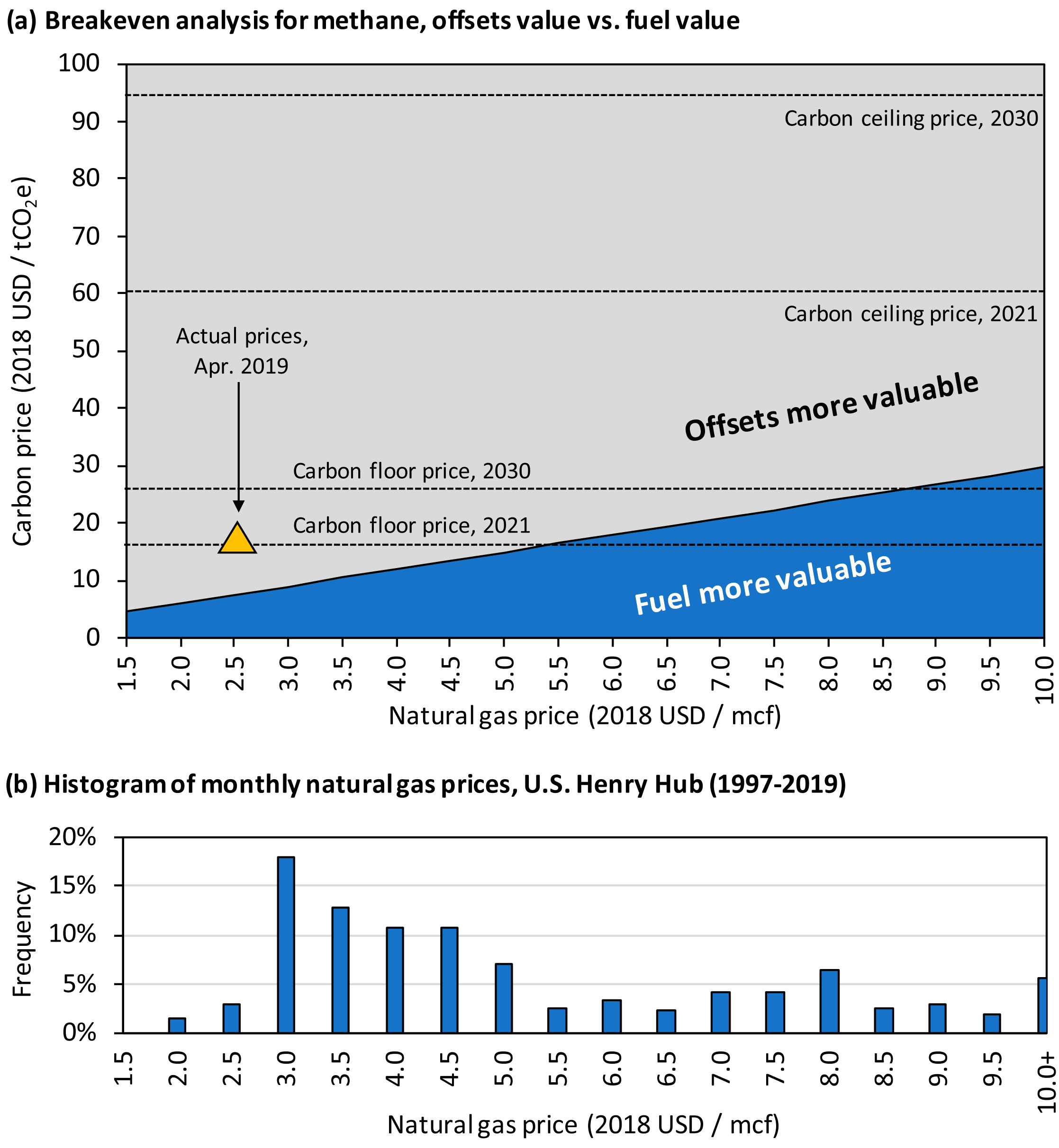

Figure 1. Income from flaring methane for offset credits versus sale of natural gas. Natural gas captured at drainage wells can be sold for fuel, or, if eligible for the MMC Protocol, flared to generate carbon offset credits. Panel (a) shows the market conditions under which flaring will be more valuable (top area) and under which fuel sales will be more valuable (bottom area). Dashed lines indicate California's minimum carbon price floor in 2021 and 2030, as well as the maximum price ceiling in 2021 and 2030. Panel (b) shows a histogram of monthly natural gas prices from 1997–2019, which have generally ranged from \$3-8/thousand cubic feet (mcf), with recent prices in the \$2-4/mcf range (U.S. EIA 2019a). If carbon prices remain near program minimums, then flaring methane to sell offset credits will generate higher revenues than selling methane as fuel, unless natural gas prices reach historically high levels. At carbon prices a few dollars above the minimum carbon price, drainage wells will generally profit more from offset sales, no matter the price of natural gas. This analysis indicates that mine owners face a perverse incentive: it is more profitable under a wide range of scenarios to flare methane captured from drainage wells, even if it would be economic to capture the methane for productive, private use.

that methane – even under relatively high natural gas prices that occurred prior to the expansion of unconventional hydrocarbon resource production in the United States. Since capital costs are often lower for flaring than for pipeline injection (US EPA, 2018) and are not taken into account in Figure 1, flaring methane instead of capturing it for beneficial use may be preferable under an even wider range of conditions.

To avoid creating an incentive for mine owners that are already pipeline injecting to shift to flaring that methane to sell offsets, the MMC Protocol excludes flaring methane from wells that captured and injected methane into pipelines within the previous year. Because protocol eligibility criteria are determined for each drainage well, however, this restriction does not affect the incentives for operators of new wells or mines, or of wells for which pipeline injection ceased for at least one year.

This suggests that operators of these wells who may have chosen to sell methane into a pipeline in the absence of the protocol might now have a financial incentive to flare this methane instead to earn carbon credits. In these cases, the protocol would not only result in non-additional crediting, but would also increase emissions by flaring methane that would otherwise have been used as a fuel.

While the first three examples of perverse incentives are just as likely to occur under first and second generation offset protocols, this last example is more likely to occur under the standardized approach since the standardized approach is more selective about the project types allowed to participate.

4. Discussion and conclusions

Drawing on qualitative and quantitative analysis of the development of two California offset protocols, we examine whether and how the standardized approach to carbon offset programme design can address three interrelated sources of over-crediting experienced under first generation offset programmes: non-additional projects, inflated baseline emissions, and perverse incentives that increase emissions. Our core finding is that large uncertainties persist in protocol-level assessments of additionality, baselines, and perverse incentives. Although the standardized approach offers offset regulators the potential to reduce, but not eliminate, the risk of over-crediting, that promise is contingent on the use of a transparent set of analytical methods.

4.1. Lessons from California's protocol design process

We highlight five key findings from our analysis that inform how ARB and other offset programme regulators can contain the risk of over-crediting using the standardized approach.

First, a simple 'common practice' assessment as used by ARB is insufficient to avoid the risk of substantial crediting from non-additional projects. As discussed in Section 3.1, ARB can reduce the risk of non-additional crediting by focusing the common practice assessment on emissions rather than number of projects; on feasible rather than all potential projects; and on project type sub-categories individually.

Second, avoiding non-additional crediting and containing the risk of over-crediting requires conducting and periodically reviewing an explicit, quantitative analysis of the expected portfolio-level balance of over- and under-crediting. Regulators could deliberately choose methods for estimating emissions reductions that under-credit the number of credits generated by an amount that at least compensates for over-crediting due to the participation of non-additional projects that meet protocol eligibility criteria. Additionality would be preserved at the protocol level if total credits generated by a protocol do not exceed conservative estimates of the effect of the protocol on emissions. Even though this approach could make some truly additional projects uneconomic, it is needed to preserve credit quality. Under this approach, protocol development would involve three estimates: (1) expected business-as-usual trends that lead to non-additional but eligible projects (non-additional credits), (2) expected additional projects (truly additional credits), and (3) estimated under-crediting from conservative protocol methods. Assumptions about business-as-usual and additional project development should be reassessed periodically, enabling the regulator to dynamically modify project type exclusions, emission estimation methods, and discount factors.

Third, offset protocols can create a range of perverse incentives that can increase emissions, requiring careful assessment, monitoring, and precautionary measures. We have shown how offset profits create incentives to keep coal mines operating longer than they otherwise would, and to shift farm production from corn to rice.

By making only some project types eligible, the MMC Protocol creates a perverse incentive for mine owners to flare methane that they might otherwise have captured for productive use as fuel. Perhaps most notably, the MMC Protocol may have even influenced federal policymakers' decision not to regulate methane emissions from coal mines on federally-owned lands.

Fourth, offset administrators could explicitly document uncertainty in all of its assessments and exclude project types for which they lack confidence that the portfolio of credits as a whole does not exceed the effect of the protocol on emissions. In some of our examples, uncertainty overwhelms emission reduction estimates. In the additionality assessment of abandoned mine methane projects, for example, uncertainty is so large that credits from these projects could be anywhere from completely additional to completely non-additional. Each type of perverse incentive we discuss could potentially result in large increases in emissions but are difficult to detect and measure. To contain the risk of substantial over-crediting, eligible project types need to be limited to those with expected reductions well above expected business-as-usual project development, with manageable uncertainty in the baseline, and without the risk of substantial effects from perverse incentives.

Fifth, implementing high-integrity carbon offset programmes requires substantial, ongoing, and often under-appreciated regulatory capacity. Resolving uncertainty in additionality, baseline emissions, and perverse incentives with *ex ante* and *ex post* review of protocol outcomes requires industry knowledge that may be out of reach to some regulators.

4.2. Implications for governance

Even with best practice protocol design and updating, carbon offsets increase uncertainty in whether an emissions cap has been met. This is because offsets pay for reductions, rather than charge for emissions. Estimating emission *reductions* requires quantifying the emissions of an unknowable counterfactual scenario, including the proportion of participating projects that are non-additional. *Paying* for reductions can create a range of perverse incentives that increase emissions such as those discussed above.

In the political and technical context of carbon offsets, uncertainty tips the scale towards over-crediting. Regulators must make subjective judgments under pressure from both buyers and sellers of credits who benefit from over-crediting, without definitive analysis from independent researchers or other financially disinterested parties. Thus, offset protocols are likely to err on the side of over-crediting in the absence of substantial internal technical capacity and political independence.

The challenge of managing uncertainty illustrates a critical disconnect between the perception and practice of cap-and-trade programmes that feature large offset programmes. Cap-and-trade programmes have been promoted as market-oriented solutions that allow private actors to identify the least-cost compliance portfolio with minimal direction from government (e.g. Washington Post Editorial Board, 2016). In turn, offsets are often seen as an essential mechanism for reducing compliance costs and extending carbon price incentives to sectors not covered by cap-and-trade. Yet the practical operation of offset programmes rests on a complex set of government-determined protocol standards needed to manage uncertainty in reductions achieved. The choices regulators make about what project types to include and how to calculate reductions drive outcomes in the market. Therefore, to the extent that offsets are used to deliver a substantial share of claimed emission reductions – as is the case in California – programme outcomes will be strongly influenced by government priorities and quality judgments, rather than primarily determined by private actors' decisions.

Under cap-and-trade, offsets are treated as accurately quantified tons of emissions reductions. Due to deep and pervasive uncertainty, however, it may be more useful to think of offsets as government-intermediated incentive programmes in which regulated emitters are allowed to invest in lieu of reducing their own emissions. Like many technology incentive programmes, offset programme outcomes are difficult to quantify and largely determined by administrative choices. Treating offsets as payments into incentive programmes, rather than as verified tons of emissions reductions, more accurately and transparently reflects the limitations, risks, administrative responsibilities, and policy choices involved in using offsets to achieve an emissions target.

Public comments at ARB offset workshops indicate that stakeholders hold profoundly different conceptions of the offset programme's purpose. Some emphasize the role offsets play by offering low cost options for reducing emissions. Others view offsets primarily as a much-needed source of funding for activities that reduce emissions and increase co-benefits in uncapped sectors. Offsets are often portrayed as win-win, delivering both benefits at once (Anderson et al., 2017). Our experience with protocol development, detailed here, shows how decisions about programme size and stringency involve trade-offs between these goals. An offset programme that prioritizes the environmental integrity of the cap-and-trade programme needs to carefully target project types that are not already being implemented on their own and for which emissions reduction estimates are relatively certain. Such a programme could miss some of the most promising opportunities to reduce emissions in the sectors eligible for offset credits (Thamo & Pannell, 2015), such as pipeline injection at underground coal mines. On the other hand, relaxed monitoring requirements or less conservative baselines for rice cultivation projects would increase the incentive to participate but would also diminish confidence in credited reductions.

The standardized approach to carbon offsets aims to avoid problems associated with widely criticized first generation offset programmes. In theory, the standardized approach provides regulators with better tools to manage the risk of over-crediting compared to project-centered programmes. However, that potential depends on regulators' use of comprehensive and transparent risk analysis that is dynamically managed on an ongoing basis. This includes protocol-level analysis as discussed and illustrated above, conservative methods for estimating emission reductions that balance anticipated over-crediting with under-crediting, restricting the programme to project types with manageable levels of uncertainty in emission reductions achieved, and ongoing monitoring of programme outcomes. Using examples from California's offset regime, we have illustrated how incomplete analysis and the lack of ongoing risk management may limit efforts to avoid the problems of earlier offset programmes. These practices could be improved, but even the most careful and conservative programme design and oversight process will result in uncertainty in true emission reductions. As a result, it may be more accurate to think of the standardized approach to carbon offsets as shifting risk from project- to protocol-level assessments, where government decisions about eligible project types and crediting rules drive private sector outcomes. It also may be more accurate to treat offset programmes as offering private actors the ability to compensate for their direct emissions, not with verified tons of emissions reductions, but rather by investing in an incentive programme resulting in difficult-to-estimate reductions.

Ultimately, offsets allow regulated entities to emit more than the programme cap levels, in exchange for a corresponding but less certain amount of reductions outside of the cap. Thus, using carbon offsets to meet an emissions cap – whether based on the standardized or first-generation approach – risks lessening total emission reductions achieved and increases uncertainty in whether a climate policy goal has been achieved. To the extent that offsets are used, lessening these risks requires a combination of systematic analysis of over-crediting risks; the political will to make conservative decisions about offset protocol design in the face of pressure to increase crediting volumes at the expense of quality; and broader climate policy design based on a realistic understanding of offsets and their limitations.

Notes

1. California Code of Regulations, title 17, § 95802.
2. California Code of Regulations, title 17, § 95854.
3. Trona is a form of sodium carbonate (used as soda ash) that is mined in the United States.
4. California Health & Safety Code § 38562(d)(2).

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Response to comments by the California Air Resources Board on

POLICY BRIEF: The California Air Resources Board's U.S. Forest offset protocol underestimates leakage

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The May 2019 policy brief, *The California Air Resources Board's U.S. Forest offset protocol underestimates leakage* (Haya, 2019), presents findings that the California's U.S. Forest offset protocol has over-credited its effect on emissions due to lenient methods for accounting for leakage. We thank the California Air Resources Board (ARB) for their recent response to this brief (ARB, 2019). Below we address the key points in ARB's response with the goal of advancing discussion about updating the protocol's leakage accounting methods to address two issues—the timing of leakage accounting, and the leakage rate applied.

Summary of the policy brief's original criticisms

California's U.S. Forest Projects offset protocol credits forestland owners for managing their lands to hold more carbon stocks than baseline levels based on common practice for the region.[1] Credits are generated on the assumption that without the offset program, participating forestland owners would harvest timber in a way that reduces on-site carbon stocks from current levels down to baseline levels.

The policy brief's criticisms concern an issue known as leakage, which occurs when reduced timber harvesting in one location induces an increase in harvesting elsewhere to meet timber demand. The policy brief analyzes 36 projects credited under the protocol, which together generated 80% of the total forest offset credits issued to date. The study concludes that 82% of credits generated by these projects are unlikely to represent emissions reductions achieved by the protocol as a result of lenient methods for accounting for leakage effects.

The protocol underestimates emissions from leakage in two ways.

- First, there is an inconsistency in the timing of leakage accounting. In the first year of an improved forest management project, the landowner receives credits for committing not to harvest timber in a way that reduces on-site carbon stocks to baseline levels. The protocol

[1] Project baselines are based on a modeled financially feasible timber harvesting scenario that is in line with regulations and other obligations and results in average on-site carbon stocks not lower than common practice in that region.

accounts for that commitment by crediting all of the on-site carbon benefits of that commitment upfront, but deducting the associated off-site carbon deficits from inducing more harvesting elsewhere (leakage) over 100 years. This frontloads the crediting, which forestland owners effectively need to pay back over the project 100-year lifetime with increased tree growth and/or sustainable timber harvesting—a commitment that may be hard to meet as forests age and the climate changes. Instead, leakage from reduced harvesting should be deducted at the same time that increased on-site carbon from that reduced harvesting is credited.

- Second, the protocol uses a low 20% leakage rate to account for increases in harvests that occur elsewhere to meet consumer demand for wood products such as building materials, packaging, and paper that we all use on a daily basis. This leakage rate is unsupported in published literature. It is important to note that the protocol uses a single leakage rate, 20%, for all projects located in widely varying forest types.

The resulting excess offset credits have important consequences for California's global warming efforts and to other jurisdictions learning from California's experience given their large quantity. The U.S. Forest Projects offset protocol has generated 80% of California's offset credits to date, and offsets can be used to achieve over half of total reductions expected by California's cap-and-trade during 2021 to 2030 (Haya, 2018). Each offset credit replaces one ton of reduction in greenhouse gas pollution that would otherwise need to happen within California's capped sectors.

We now address responses from ARB.

Timing: projects start in greenhouse gas debt

ARB (May 30, 2019): "Should carbon stored above baseline in first year be considered "greenhouse gas debt"? No, crediting is based on activities to date, not future performance"

Projects are awarded credits in their first year for the commitment to hold and increase forest carbon over 100 years, not on the basis of project activities to date.

In its first year, each project receives credits for the carbon already held on-site, with the number of credits calculated as the difference between current carbon stocks and the 100-year average of a modeled baseline scenario, minus the estimated increase in emissions off-site due to the displacement of timber harvesting to elsewhere (i.e. minus the effects of leakage in year one). Each subsequent year, projects are rewarded for any increase in on-site carbon storage compared to the previous year, minus carbon releases from leakage in those years. Most projects generate a large sum of credits in their first year, followed by smaller amounts each subsequent year. The forest projects analyzed started with on-site carbon stocks 48% higher than their baselines on average. Forestland owners must commit to holding the credited on-site carbon for at least 100 years and to increasing carbon storage for 100 years to cover any carbon losses from leakage.

What is the justification for awarding forestland owners offset credits for on-site carbon they already hold above baseline levels? It is important to remember that offset credits are used in lieu of reductions in California's capped sectors. California's global warming law, AB 32, specifies that offsets should not generate credits for past behavior, but must only credit *additional* reductions caused by the offset program. Credited reductions have to be "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur" (California Health & Safety Code § 38562(d)(2)). In other words, only truly new units of sequestration should be used to offset the emissions of the entities that will purchase the ARB offset credits. That some forestland owners across the United States historically managed their lands to hold more carbon than the average does not in itself justify increases in emissions in California's capped sectors above the cap.

The credits generated in the first year of a project must therefore be for a change in forest management practice caused by the protocol. The protocol estimates emissions reductions based on the assumption that without the offset program, forestland owners would harvest participating lands so that average on-site carbon stocks fall to baseline levels. ARB chose to credit forestland owners for refraining from this harvesting in the first year of each project even though it is unknown when and if carbon stocks would have been reduced without the offset protocol. In contrast, ARB chose to account for the carbon releases associated with the resulting leakage evenly over a project's 100-year lifetime. Ignoring whether it is justified to generate credits today for a commitment not to reduce carbon stocks over 100 years, to be consistent, the leakage associated with the reduced harvesting credited in a project's first year should also be accounted for in the first year. American Carbon Registry's voluntary market Improved Forest Management protocol already accounts for leakage in this way (American Carbon Registry, 2018).

In addition to consistency, there is a second reason to deduct leakage at the same time that the associated increases in on-site carbon stocks are credited. Practically, to maintain higher on-site carbon stocks, forestland owners will let the average tree age increase. There is considerable empirical evidence that growth rates decline as the average tree age increases in most commercial species in North America (Gray, Whittier, & Harmon, 2016; Ryan, Binkley, & Fownes, 1997; Tang, Luyssaert, Richardson, Kutsch, & Janssens, 2014). So project forest stands may experience declining rates of annual carbon sequestration. ARB's protocol, by accounting for the on-site effects of reduced harvesting in the first year of the project, while requiring landowners to pay back the leakage associated with that reduced harvesting over 100 years, creates a challenge for participating landowners. To cover the emissions impact from leakage, landowners must continue to increase on-site carbon storage for 100 years, and/or to harvest more to prevent leakage. This requirement can be difficult to meet consistently year-after-year for 100 years with older forests. This need to pay back credits (greenhouse gas debt) over the life of a project would partly be avoided if the leakage associated with increased on-site carbon stocks compared to the baseline at the start of the project was also deducted at the start of the project.

Leakage rate: ARB uses a low leakage rate unsupported by published literature

ARB (May 30, 2019): "Are cited leakage studies in the policy brief applicable to the Forest Protocol? No, comparing the cited studies to the activities included in the Forest Protocol results in an apples-to-oranges comparison"

ARB cannot point to evidence supporting its choice of a 20% leakage rate from reduced timber harvesting within the United States. Whether reduced harvesting is temporary, as it could be with managed timberlands, or long-term as in conservation forestry, reduced harvesting causes leakage as other forests will need to be harvested to meet demand for timber products. Existing published literature on leakage rates from reduced timber harvesting in the United States, though imperfect, suggests that leakage is likely to be 80% or higher. A high leakage rate is also in line with a common sense understanding of the U.S. timber market.

Published literature on leakage rates

Only three studies have been published that estimate leakage rates from reductions in timber harvesting in the United States: Wear & Murray (2004), Gan & McCarl (2007), and Murray, McCarl, & Lee (2004).

Wear & Murray (2004) use econometric modeling to trace the effects of reductions in federal timber sales in the western United States in the late 1980s through the 1990s. They estimate that 84% of the reduced timber production from federally-owned Douglas-fir and pine forests in Oregon and Washington was displaced to elsewhere within North America.

Gan & McCarl (2007)*,* use a computable general equilibrium model, and find that if timber production were reduced in the United States 77% of that that timber harvesting would be displaced to other countries.

Murray, McCarl, & Lee (2004) perform a more refined analysis that not only traces leakage in terms of board feet of timber harvested, but also takes into account the carbon implications of that shift in harvesting, given that harvesting different forest types results in different amounts of carbon loss per board foot of timber produced. Focusing only on leakage within the United States, they estimate carbon-density weighted leakage rates of for old growth forest in the Pacific Northwest to be 16% and for mature forests in the South Central region to be 68%. This study also assesses leakage for avoided deforestation projects, but these lower figures are less relevant to improved forest management projects which generate leakage primarily from reduced timber harvesting rather than from reduced conversion of forests to other land uses.

Even though Murray, McCarl, & Lee use a more refined method for estimating leakage, applying these figures to ARB's protocol has two shortcomings. First, the article only analyzes leakage within the United States. The other two articles predict substantial international leakage, so the figures in Murray, McCarl, & Lee underestimate leakage. Second, since neither forest type is representative of the portfolio of forests participating in California's protocol it was unclear how to translate those two carbon density analyses into the effects of offset projects all over the United States. It is appropriate to apply a lower leakage rate to reduced harvesting in old growth forests. But the majority of forestlands participating in the protocol are not old growth forests. Without refined carbon-density data in many regions, it is more accurate to assume no difference in carbon density between the forests where logging is reduced and where leakage occurs, as is done by the two articles cited in the policy brief, rather than extrapolating carbon density analysis from only two specific forests types to reduced harvesting anywhere in the United States.

Further, the 68.3% leakage rate within the United States is more than the within-U.S. leakage rate estimated by Wear & Murray, (57.7%, see table 8). So if the rate of international leakage were the same in the South Central of the United States, as it is in the Pacific Northwest, then the carbon-density-based leakage rate for reduced harvesting in the South Central region is likely to be higher than 84%.

All three articles underrepresent total leakage from conservation on U.S. forestlands. Gan & McCarl only estimate international leakage, ignoring leakage that might occur among forestland within the United States. Wear & Murray only estimate leakage in North America, ignoring leakage that could occur elsewhere. As noted, Murray, McCarl, & Lee only estimate leakage within the United States. These three articles suggest that the leakage rate from reduced timber harvesting in the United States is greater than 80%.

As Professor Murray noted in a letter from June 3, 2019 (Murray, 2019), the two studies cited by the policy brief are not ideal predictors of leakage rates from improved forest management projects in the United States that reduce timber harvesting, and more research is needed. A more refined analysis of the carbon densities and regional timber markets that also take into account potential land conversion effects would be more accurate. However, Murray, McCarl, & Lee (2004) is the only study that we are aware of that tries to do this and as noted above, they only do the analysis for two forest types. The short-term reduction in the output of generic softwood lumber from federal lands in the Pacific Northwest is more similar to improved forest management projects on generic private timberland than modeling of changes in land use and forest utilization across other forest types. They are also more relevant than leakage estimates from reforestation and avoided deforestation projects. Given this, the best published estimates of leakage are the two studies cited by the policy brief.

Given the limited studies available and the need to choose a method for estimating leakage under ARB's offset protocol, the studies that are most relevant to improved forest management offset projects point to a leakage rate that is higher than 80%. This is supported by a common sense understanding of the timber market in the United States and in neighboring Canada.

A high leakage rate is expected from the well-integrated U.S. timber market

Let's take a look at what a 20% leakage rate means. On the U.S. west coast, more than 90% of the houses we all live in are built with wood (Butsic et al., 2017). If the ARB 20% leakage rate is accurate, that would mean either that four out of fives houses that would have been built from the timber produced by the offset project lands are never built, or they are built but with other materials such as cement and steel which are more greenhouse gas intensive than wood. The former option is simply not credible; the latter suggest that the protocol is perversely incentivizing an increase in emissions.

When estimating the full global change in forest carbon sequestration from a project that reduces timber harvesting in the United States, whether temporarily or long-term, it is logical to start with a leakage number close to 100% (van Kooten, Bogle, & Vries, 2014). The lumber market in the

United States is extremely well integrated across U.S. regions and with Canada. Marginal shortages in this well-traded commodity from one supplier will simply be made up from putting in a bigger order to other suppliers. For example, the reduction in large volumes of timber harvested on federal lands the Pacific Northwest in the 1990s was nearly all made up by increased sales and harvests from other producers in Canada and the U.S. Southeast (Wear & Murray, 2004).

ARB requires all offset protocols to take a conservative approach to addressing uncertainty in emissions reduction estimates. ARB defines "conservative" as choosing emission reduction methods that are more likely to under-credit than to over-credit (California Code of Regulations, title 17, § 95802). The burden of proof is on ARB to justify the use of a low leakage rate that requires the assumption that many homes in the United States will simply not be built due to lower global harvest rates of commercial softwood lumber species. There is no justification for a 20% leakage rate for U.S. forests in the published literature. Common sense understanding of the U.S. timber market and the best the literature estimating leakage rates from reduced timber harvesting in the United States point to a leakage rate that is 80% or higher.

The policy brief accurately interprets the protocol

ARB (May 30, 2019): "Does UC Berkeley policy brief accurately portray Forest Protocol leakage considerations? No, the policy brief misrepresents how leakage is accounted for in the Protocol. Policy brief only identifies the 20% activity-shifting leakage in the Protocol, and asserts it should be 80% based on inapplicable studies. Policy brief neglects to mention the 80% market-shifting leakage included in the Protocol."

The protocol only applies a single 20% rate to estimate the carbon impacts of leakage. The 80% figure mentioned by ARB is mathematically derived from the 20% leakage rate and is used to calculate the effects of the protocol on carbon held long-term in harvested wood products, rather than the application of a second separate market-shifting leakage rate.

To ensure that the policy brief is based on an accurate understanding of the protocol, the analysis starts by recalculating the number of credits generated, and does so very accurately for all 36 projects analyzed.

The analysis accurately reproduces ARB's calculations

The analysis presented in the policy brief accurately reproduced the calculations for the credits issued for all 36 projects analyzed before evaluating the impact of ARB's problematic treatment of leakage, as discussed above. Across the 36 projects, the policy brief's replicated calculation of the total number of credits issued for those projects differed from the actual number reported in project documents by only 0.1%. This indicates that the analysis is consistent with ARB's own calculations.

The analysis spreadsheet, along with a table comparing the number of credits calculated by this spreadsheet and reported in the project documents for all 36 projects, are available on the Berkeley Carbon Trading Project website. An earlier version of this spreadsheet was shared with ARB for their comment on April 9, 2018 without a response.

The 80% factor in Equation 5.1 is mathematically derived from the choice of a 20% leakage rate, and is not the application of a separate 80% leakage rate

The calculation in the analysis spreadsheet is based on Equation 5.1, which is used to calculate the emissions reduced by each improved forest management offset project. ARB notes in their response that they use two leakage rates in that equation—20% and 80%. This is not the case. The 80% factor in Equation 5.1 is mathematically derived from the use of a 20% leakage rate. Here is a brief explanation of why this is. For the first year of each project, Equation 5.1 is used to calculate the emissions reduced by the project as the difference in actual on-site carbon compared to the baseline scenario, minus two factors:

Factor 1: Carbon held long-term in harvested wood products. When timber is harvested, not all of the carbon taken from the site enters the atmosphere in the near term; some remains long-term in wood products like houses and furniture. The number of credits awarded to projects is lessened by the reduction in carbon held long-term in wood products.

Factor 2: Leakage. The protocol takes into account the loss of carbon due to the leakage induced by the project—the displacement of timber harvested to other forestlands.

These two factors interact. When timber harvesting is displaced to somewhere else, some of that harvested forest carbon induced by the project ends up being held long-term in timber products. If 20% of the reduction in timber harvesting on project lands is displaced to somewhere else, 20% of the reduction in carbon held long-term in harvested wood product is made up for by that increase in harvesting on those other lands. So for Factor 1, instead of deducting 100% of the reduction in carbon held long-term in harvest wood products, only 80% is deducted. The 80% leakage factor in Equation 5.1 is thus mathematically derived from the use of a 20% leakage rate.[2] If the 20% leakage rate were increased, the 80% leakage factor would decrease by the same amount.

Recommended changes to the protocol

The policy brief lays out how the protocol can be amended to more accurately account for leakage from improved forest management projects:

(1) In the first year of each project, leakage should be deducted equal to the product of the leakage rate and the difference in on-site carbon stocks between the project and the baseline. This difference is the loss that would occur if the forestland owner chooses to manage their

[2] Here is a specific example using figures from the sample project described by ARB (2019, p12). According to ARB's example, each year in the baseline, 20,000 tons of carbon in trees would have been harvested, and that harvesting would have resulted in 4,500 tons of carbon held long-term in wood products. (I include here the longer descriptions of these values as per Equation 5.1 in the protocol itself.) In the example project, 10,000 tons of carbon in trees was actually harvested, resulting in 2,000 tons of carbon being held long-term in harvested wood products. Using the protocol's 20% leakage rate, we can calculate the effect of the protocol on carbon held long-term in harvested wood products as: 80% of (4,500 minus 2,000) (the second term in the equation). The 80% factor takes into account that 20% of harvesting is leaked to elsewhere, so 20% of the reduction in harvested wood products produced by the project is compensated for by increased harvesting elsewhere due to leakage.

land as per the baseline scenario, which the protocol assumes would happen without the offset project. In all subsequent years, the average carbon in harvested trees in the baseline scenario can be recalculated so that the average harvest rate over 100 years remains the same;

(2) The protocol should apply a leakage rate that is at least 80%.

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Report 14: March 2013

AN AUDIT OF CARBON NEUTRAL GOVERNMENT

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Auditor General
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Auditor General
of British Columbia

The Honourable Bill Barisoff
Speaker of the Legislative Assembly
Province of British Columbia
Parliament Buildings
Victoria, British Columbia
V8V 1X4

Dear Sir:

I have the honour to transmit to the Legislative Assembly of British Columbia my 2012/2013 Report 14: *An Audit of Carbon Neutral Government.*

In its 2007 Speech from the Throne, the provincial government announced its goal of becoming carbon neutral by 2010. In addition to making capital investments and reducing greenhouse gases, a significant part of its plan was the purchase of carbon offsets.

This audit examined two projects which accounted for nearly 70 percent of the offsets purchased by government to achieve their claim of carbon neutrality: the Darkwoods Forest Carbon project in southeastern B.C. and the Encana Underbalanced Drilling project near Fort Nelson. However, this claim of carbon neutrality is not accurate, as neither project provided credible offsets.

John Doyle, MAcc, FCA
Auditor General
Victoria, British Columbia
March 2013

CONTENTS

CLIMATE CHANGE IS SEEN BY MANY as the major environmental issue facing us today. The evidence of its impacts (extreme storms, increased droughts, warming and cooling shifts) is a constant feature in the daily news and the lives of many. With it comes the increasing recognition from governments around the world that greenhouse gas emissions (GHGs) must be reduced to mitigate these impacts.

In its 2007 Speech from the Throne, the provincial government announced its goal of becoming carbon neutral by 2010. In addition to making capital investments and reducing GHGs, a significant part of its plan was the purchase of carbon offsets. These offsets represent a reduction or sequestration of greenhouse gas emissions that can be used to compensate for emissions from another organization, such as a public sector body. Government established the Pacific Carbon Trust (PCT), a Crown corporation, to purchase the carbon offsets needed by government to meet its carbon neutral goal.

This audit examined two projects which accounted for nearly 70 percent of the offsets purchased by government to achieve their claim of carbon neutrality: the Darkwoods Forest Carbon project in southeastern B.C. and the Encana Underbalanced Drilling project near Fort Nelson. However, this claim of carbon neutrality is not accurate, as neither project provided credible offsets.

The credibility of carbon offsets is the crux of the entire concept. Within a complex system of dense terminology and calculations is mired a common sense test: Would the project have happened in the absence of carbon finance? Regarding the projects examined, the answer is a straightforward "yes".

The main reason for this is that offsets can only be credible in B.C. if, among other things, the revenue from their sale is the tipping point in moving forward on a project. It must be an incentive, not a subsidy, for the reduction of GHGs. Yet neither project was able to demonstrate that the potential sales of offsets were needed for the project to be implemented. Encana's project was projected to be more financially beneficial to the company than its previous practices, regardless of offset revenue, while the Darkwoods property was acquired without offsets being a critical factor in the decision. In industry terms, they would be known as 'free riders' – receiving revenue ($6 million between the two) for something that would have happened anyway.

The challenge of proving the credibility of carbon offsets is not limited to B.C. For example, the United Nation's Clean Development Mechanism, the largest offset certification body in the world, recently acknowledged that it needs to enhance its own processes and outcomes. It is, in part, recognition of these concerns that led me to undertake this audit.

With all my public reports, I aim for the results to be useful to individuals and groups beyond the specific organization audited, so that British Columbians and their elected representatives can get full value for the work of my Office. This audit is no different – not only would the Pacific Carbon Trust and the Climate Action Secretariat benefit from it, but so too could the broader international carbon offset community. However, I have reasons to be concerned whether such benefits will be realized.

John Doyle, MAcc, FCA
Auditor General

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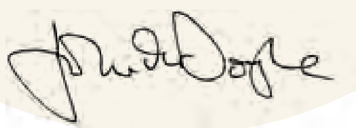
Mike McStravick,
Director

Tanya Wood,
Senior Performance
Audit Associate

AUDITOR GENERAL'S COMMENTS

Of all the reports I have issued, never has one been targeted in such an overt manner by vested interests, nor has an audited organization ever broken my confidence, as did the senior managers at PCT by disclosing confidential information to carbon market developers and brokers. The orchestrated letter-writing campaign from domestic and foreign entities which followed this disclosure demanded considerable staff time, and resulted in the delay of this report. I cannot sufficiently express my surprise and disappointment that a public sector entity, with a fiduciary duty to the people of British Columbia, chose to expend its time and energy in this manner, rather than addressing the concerns raised in the audit – and that they did so with the knowledge of their governing board.

In that context, government's response is small encouragement, and my Office will continue to follow-up on their progress in implementing the recommendations in this report.



John Doyle, MAcc, FCA
Auditor General of British Columbia
March 2013

EXECUTIVE SUMMARY

Climate change, which is widely attributed to rising levels of greenhouse gas (GHG) in the atmosphere as a result of fossil fuel use and land-clearing, is considered by many to be the largest threat to the global environment today. In its 2007 Throne Speech, the Province announced it would be taking an aggressive stand to reduce emissions of greenhouse gases. Bill 44, the *Greenhouse Gas Reduction Targets Act* (GGRT), called for a 33 percent reduction of GHG emissions by 2020 and 80 percent by 2050. It also required each public sector organization to become carbon neutral by 2010. The Province announced it had achieved this goal in July 2011.

While the Act called on public sector organizations — which includes all core government ministries, school districts, post-secondary institutions, Crown corporations and health authorities — to pursue actions to minimize their greenhouse gases, there are some emissions that cannot be avoided. In order to achieve carbon neutrality, public sector organizations are required to purchase eligible carbon offsets.

The Ministry of Environment's Climate Action Secretariat (CAS) directs government's policy actions in the areas of climate change and facilitates the legislated mandate to be carbon neutral. The Pacific Carbon Trust (PCT) is a Crown corporation with the mandate to purchase quality B.C.-based offsets to help the public sector meet their carbon reduction goals and to help grow B.C.'s low-carbon economy.

We carried out this audit to determine whether government achieved its objective of creating a carbon neutral public sector for 2010. We asked three questions:

1. Has government established reasonable procedures to allow public sector organizations to determine their greenhouse gas emissions and assessed whether they have taken sufficient actions to reduce those emissions?
2. Has the Pacific Carbon Trust purchased credible offsets?
3. Is government evaluating and reporting on the achievement of its objectives?

AUDIT CONCLUSION

We concluded that the provincial government has not met its objective of achieving a carbon neutral public sector:

- Government has established reasonable procedures to allow public sector organizations to determine their greenhouse gas emissions. However, government has not yet established criteria to evaluate whether government as a whole is taking sufficient actions to reduce emissions.
- Pacific Carbon Trust has not purchased credible offsets.
- Government is reporting on its efforts to reduce emissions and its progress in achieving a carbon neutral government. However, the PCT has not provided sufficient information in its reporting about the cost and quality of its purchases.

SUMMARY OF KEY FINDINGS

Government is determining greenhouse gas emissions but has not established criteria to evaluate whether reduction actions are sufficient

The *Greenhouse Gas Reduction Targets Act* requires all government organizations to "pursue actions to minimize their greenhouse gas emissions" for each calendar year, beginning in 2010. We found that while some organizations had GHG reduction targets, most did not. We also found the CAS has not established criteria to evaluate whether public sector organization's actions to reduce emissions are sufficient.

The Pacific Carbon Trust has not purchased credible offsets

We looked at two offset projects that together accounted for approximately 70 percent of the total offsets for 2010 – the Darkwoods Forest Carbon Project, comprising 450,000 offsets and Encana's Underbalanced Drilling Project, comprising nearly 85,000 offsets. We found that both offset projects started without showing that the value of offsets was considered to the extent that it provided the incentive for going ahead – an important consideration for demonstrating the eligibility of offset projects.

We also found that neither project had a baseline that could be supported. The Darkwoods baseline was not conservative and did not recognize the legal constraints on the project area. The Encana baseline was not supported by an appropriate test to show it was the most likely scenario.

Government and the Pacific Carbon Trust report on their achievements, but improvements could be made

We found that government reported on actions taken to reduce emissions, on the total emissions generated, the emissions required to be offset, and the offsets purchased. Although the reports highlight specific work taking place across the public service, they did not sufficiently address the risks facing public sector organizations in reducing GHG emissions, nor did the reports discuss key barriers.

We also found that while the Pacific Carbon Trust reports its offset purchases, their reporting lacked details needed to demonstrate the cost-effectiveness of the offsets purchased. The PCT is restricted to purchasing offsets generated in B.C. and had challenges demonstrating value-for-money in its purchases. For the projects examined in this audit, we found that the Pacific Carbon Trust had to pay more than market rates for both offset projects.

SUMMARY OF RECOMMENDATIONS

WE RECOMMEND THAT:

1 The Climate Action Secretariat work with public sector organizations to ensure each is pursuing reasonable actions to reduce emissions. As part of this, government should consider establishing public sector emission reduction targets.

2 The Climate Action Secretariat ensure supplementary guidance to the Emission Offsets Regulation be finalized and adhered to.

3 The Pacific Carbon Trust, to better manage offset purchase risks, ensure that the results of its due diligence efforts are satisfactorily analyzed, concluded and documented.

4 The Climate Action Secretariat provide stronger oversight to ensure that the offsets purchased on behalf of government are credible.

5 The Pacific Carbon Trust provide greater transparency about the cost-effectiveness of its purchases.

6 The Climate Action Secretariat and the Pacific Carbon Trust ensure that reporting on carbon neutrality assesses the trade-offs between reducing government emissions and offsetting those emissions through the purchase of offsets.

In 2010, BC became the first carbon neutral government in North America. We met this achievement again in 2011 and are poised to do so for 2012 as well. The Auditor General of British Columbia has completed a performance audit of our first year as a Carbon Neutral Government and in particular two of the first offsets purchased by the Pacific Carbon Trust.

The Government appreciates the Auditor General's recommendations on how we can improve the program. We will move forward on these recommendations and have already accomplished a lot in these areas while the audit has been underway, including:

- Developed a diversified offset portfolio of 32 projects in all sectors of the economy and all regions of BC;
- Completed extensive engagements across the public sector, with offset professionals, and with academics and experts to improve our Carbon Neutral Government program;
- Eliminated reporting costs to the entire public sector;
- Implemented a new Carbon Neutral Capital program which has already provided $10 million dollars over two years in new capital funding to the education sector;
- Created a Carbon Offset Advisory Panel to advise the Pacific Carbon Trust on the development of its offset portfolio;
- Provided greater transparency by publicly releasing the purchase price of every offset in the Pacific Carbon Trust's portfolio; and,
- Initiated a review to determine if the financial surplus we currently generate from offset purchases should be used to lower public sector costs or invested to further reduce emissions.

BC is recognized internationally as a climate change leader, and our offset system is based on international standards. BC is the chair of the Western Climate Initiative's offsets committee, and is referred to by the International Emissions Trading Association as a best practice for offsets internationally. A key feature of BC's offset program is that third party accredited professionals validate and verify projects to ensure they meet the requirements of the Emission Offsets Regulation. This approach is consistent with new offset systems now being implemented in Quebec, California, Australia, China, South Korea, and elsewhere.

BC stands by the importance of having qualified and independent experts make the professional judgement calls necessary to determine whether a project can be considered an offset, but note that the Auditor General has a difference of opinion on the judgement calls made on two offset projects. We will work with the private audit firms involved, as well as the American National Standards Institute, to ensure that BC offsets are credible.

BC is the first Carbon Neutral Government in North America. Program improvements we have made since 2010 underscore our commitment to be the best. Within that context, we will incorporate the Auditor General's recommendations into our strategic planning for carbon neutral government as noted below to further strengthen our program.

RESPONSE FROM THE MINISTRY OF ENVIRONMENT

RECOMMENDATION #1:

The Climate Action Secretariat work with public sector organizations to ensure each is pursuing reasonable actions to reduce emissions. As part of this, government should consider establishing public sector emission reduction targets.

The audit examined BC's Carbon Neutral Government achievement in 2010, our first year of establishing our carbon footprint and the baseline to assess our future actions to reduce emissions.
By law, all public sector organizations are required to publicly report on their emissions as well as the actions they have taken to reduce them. The Climate Action Secretariat has worked across the public sector on these plans and has highlighted key success stories through our Carbon Neutral Government reports in 2010, 2011, and soon for 2012.

To reduce emissions across the public sector, BC has taken efforts such as :

- committed $75 million from 2007 to 2010 to reduce emissions across the public sector
- reduced emissions from core government travel by 60%;
- required that new government buildings be built to LEED Gold or equivalent standards
- required that all new vehicle purchases first consider hybrid or clean energy vehicles;
- established agreements with BC Hydro and Fortis BC to provide financial incentives to energy projects as well as energy managers to work with public sector organizations across the province to develop plans to reduce emissions and save energy costs;
- Established a new Carbon Neutral Capital Program that has provided $10 million towards energy efficiency projects in school districts to help them reduce GHG emissions;
- Used the fixed price of offsets of $25/tonne as a concrete financial incentive to change capital planning and influence behaviour change across the public sector.

In support of this recommendation, the Climate Action Secretariat will take greater efforts to promote emission reductions across the public sector. As we report on BC's Carbon Neutral Government commitment over time, we will assess whether emission reductions are broadly in line with BC's provincial greenhouse gas reduction targets to ensure government's achieving appropriate results.

RECOMMENDATION #2:

The Climate Action Secretariat ensure supplementary guidance to the Emission Offsets Regulation be finalized and adhered to.

The audit has assessed two of the first offset projects purchased by the Pacific Carbon Trust. Since that time, the Climate Action Secretariat has been working with the Pacific Carbon Trust and the professional community to ensure that roles and responsibilities are clear and that the requirements of the Emission Offset Regulation are understood by all parties.

In support of this recommendation, the Climate Action Secretariat will review guidance provided to date with the Pacific Carbon Trust and the professional community and formalize the guidance and procedures for offsets.

RECOMMENDATION #3:

The Pacific Carbon Trust, to better manage offset purchase risks, ensure that the results of its due diligence efforts are satisfactorily analyzed, concluded and documented.

The Pacific Carbon Trust is a relatively new Crown corporation supporting the development of a new market in BC, and as such it recognizes the need to continuously improve, and implement processes to manage risk. With this in mind, PCT has been working with Deloitte & Touche to improve its business processes, policies and risk management. Since 2010, Pacific Carbon Trust has:

- Supported the development of provincially-approved protocols such as the Protocol for the Creation of Forest Carbon Offsets in BC.
- Implemented risk management policies and procedures including an enterprise risk management registry.
- Implemented a second risk assessment for all offset projects.
- Clarified Pacific Carbon Trust's role in relation to protocol development.
- Initiated monthly data reporting to better monitor supply chain risk.

In support of this recommendation, Pacific Carbon Trust will continue to work with Deloitte & Touche and other industry experts to implement continuous improvement. Deloitte has provided a follow-up performance review to assess PCT's implementation of previous recommendations and to suggest further areas for improvement.

RECOMMENDATION #4:

The Climate Action Secretariat provide stronger oversight to ensure that the offsets purchased on behalf of government are credible.

The Emission Offset Regulation defines BC's offset system and includes key elements to ensure offsets are credible including:

- Projects must be validated and verified by independent, accredited third parties;
- Offsets are purchased by a Crown Corporation arms-length from government and under the direction of an independent Board of Directors; and,
- A Director at the Climate Action Secretariat has statutory authorities to work with the professional community as well as set protocols to ensure the effectiveness of BC's offsets system.

The Climate Action Secretariat has been working with the Pacific Carbon Trust and the professional community to continuously improve BC's offset system. This has included increasing the number of CAS employees with ISO training in validation and verification of offsets.

In support of this recommendation, the Climate Action Secretariat will consult with the professional community and international experts and release formal procedures on how the Director's oversight role will be delivered.

RECOMMENDATION #5:

The Pacific Carbon Trust provide greater transparency about the cost-effectiveness of its purchases.

With the maturation of the BC carbon market and a portfolio of more than 30 carbon offset projects, Pacific Carbon Trust now has sufficient data to establish the range of prices it will negotiate with suppliers. The purchase price ranges correspond to the three project types in the PCT portfolio: forest sequestration, energy efficiency and fuel switching. Pacific Carbon Trust is restricted to purchase offsets within BC, and each project is evaluated on its own costs, risks and value.

- On February 15, 2013, the Pacific Carbon Trust released a pricing framework for each of the three project types in its portfolio. This will help guide potential offset project developers as they build financing for their projects.
- In addition, PCT has made all carbon offset payment and pricing information from 2009 through 2011 available on its **website**.
- Going forward, PCT will release this information on an annual basis every June in conjunction with the release of its annual carbon neutral government portfolio.

The carbon market has sufficiently matured to allow for more transparent financial reporting and a clear pricing structure ensures that releasing these details will not create any potential financial risk to B.C. taxpayers.

RECOMMENDATION #6:

The Climate Action Secretariat and the Pacific Carbon Trust ensure that reporting on carbon neutrality assess the trade-offs between reducing government emissions and offsetting those emissions through the purchase of offsets.

Since the time of the audit, BC has reported on its 2011 Carbon Neutral Government commitment and will soon report on its 2012 commitment. Since beginning this program, the Climate Action Secretariat, the Pacific Carbon Trust and the broader public sector has been able to develop a series of public information products communicating the value of Carbon Neutral Government, including both the benefits of reducing emissions and energy costs in the public sector as well as the value of the Pacific Carbon Trust's offset portfolio across BC.

The Climate Action Secretariat and the Pacific Carbon Trust have also introduced since 2010 expert committees to improve the measurement and reporting of actions taken by PSOs as well as the effectiveness of the Pacific Carbon Trust's offset portfolio.

In support of this recommendation, Government will take further actions to communicate the value of reducing public sector emissions as well as investing in emission reductions across BC.

BACKGROUND

Climate change is believed by many to be the biggest global environmental threat of this century. The provincial government has reported that British Columbia is experiencing the symptoms of climate change right now – from the pine beetle epidemic to increased forest fires and flooding – which is costing the province millions of dollars. Scientists attribute much of the climate's warming over the last half-century to human influences — in particular the burning of fossil fuels and land-clearing. These activities have been linked to increased carbon dioxide and other greenhouse gases (GHGs) in the atmosphere.

In the 2007 Speech from the Throne, the provincial government announced it would take an aggressive stand to reduce GHG emissions. It passed the *Greenhouse Gas Reduction Targets Act* that put into law B.C.'s targets for carbon reduction: 33 percent by 2020 and 80 percent by 2050. The Act also includes an annual requirement for the public sector to achieve carbon neutrality beginning in 2010. Government sees its carbon neutral commitment as being an important way to demonstrate leadership in climate action.

This commitment covers the entire public sector, including all core government ministries, school districts, post-secondary institutions, Crown corporations and health authorities.

The Act requires each public sector organization to become **carbon neutral** beginning in 2010. To be carbon neutral, a public sector organization must:

- pursue actions to minimize its GHG emissions for each calendar year;
- determine its GHG emissions for each calendar year;
- purchase **carbon offsets** by the end of June in the following calendar year; and
- issue a Carbon Neutral Action Report each year to describe the actions taken to reduce emissions and plans to continue minimizing those emissions.

In July 2011, British Columbia announced it was the first jurisdiction in North America to achieve carbon neutrality.

CARBON NEUTRAL
The concept of achieving carbon neutrality involves purchasing carbon offsets for any emissions generated to achieve net-zero GHG emissions.

CARBON OFFSET
A **carbon offset** represents a reduction or sequestration of GHGs generated by activities – such as improved energy efficiency – that can be used to compensate for, or offset, the emissions from another source, such as a plane trip. One carbon offset represents the reduction of one tonne of carbon dioxide (or its equivalent in other GHGs).

Carbon Neutrality: Roles and Responsibilities

The Climate Action Secretariat (CAS) was established in 2007 to direct the Province's policy actions related to climate change and oversee the legislated mandate to be carbon neutral. In 2008, government then established the Pacific Carbon Trust (PCT), a Crown corporation with the mandate to purchase B.C.-based offsets to help the public sector meet its carbon reduction goals and help British Columbia develop a low-carbon economy.

Achieving carbon neutrality through this initiative is a four-step process (Exhibit 1).

EXHIBIT 1: The four steps to achieving carbon neutrality in British Columbia

MEASURE	Public sector organizations (PSOs) measure the energy consumed from their buildings, transportation fleets, equipment and paper use. Core government (ministries and agencies) also measure emissions from travel.
REDUCE	Putting a price on GHG emissions is intended to create an incentive for public sector organizations to take reduction action. Such actions may include reducing staff travel, promoting behavioural changes such as turning off computers and lights when not in use, and retrofitting buildings to make them more energy efficient. Even with best efforts to reduce, PSOs will still generate greenhouse gas (GHG) emissions.
OFFSET	Public sector organizations pay the Pacific Carbon Trust $25 per tonne of carbon dioxide equivalents (CO_2e)* they generate. In turn, the Pacific Carbon Trust uses these funds to purchase offsets.
REPORT	Government reports annually on the results. In this way, legislators and the public learn about the outcomes achieved (both positive and negative) from reducing and offsetting GHG emissions, and government can determine what changes might be needed to improve the outcomes.

Adapted from *Carbon Neutral B.C. – Transforming B.C.'s Public Sector Report*

* CO_2e is a common unit of measurement used to compare the relative climate impact, or global warming potential, of the different greenhouse gases. Global warming potential is a relative scale that compares the gas in question to that of the same mass of carbon dioxide.

Ensuring the integrity and credibility of carbon offsets

Under the *Greenhouse Gas Reduction Targets Act*, carbon offset projects must meet the criteria laid out in the Emission Offsets Regulation. The regulation, based on international standards, is intended to ensure that offsets purchased by the PCT are, among other things, measureable, permanent and additional to business-as-usual.

One of the most challenging aspects of ensuring the integrity and credibility of offsets is demonstrating that the project in question is additional to business-as-usual — also referred to as demonstrating "additionality." (See Appendix 1.)

The Emission Offsets Regulation includes several requirements designed to ensure projects demonstrate that they are additional to business-as-usual. These requirements include:

- The project has to start after November 29, 2007, the date of the passage of the Act.
- The project cannot be required by law or regulation.
- It must be demonstrated that the project faces financial, technological or other obstacles which are overcome, or partially overcome, by the incentive of being recognized as an emission offset.
- The financial implications of the baseline scenario need to be considered.

Beyond these requirements, the PCT has also indicated that proponents must have considered and included the value of developing offsets as part of the justification for going ahead with the project. When projects have already started (or have been completed) it can be difficult to demonstrate that offsets were part of the decision to implement the project. Supporting evidence in these circumstances may include the original business case, legal documents or board minutes showing how the value of offsets was factored into the decision to implement the project. If this evidence does not exist, the offset purchaser may be investing in projects that would have happened anyway. A project that would have happened anyway is not additional.

Another important characteristic of credible offsets is a conservative estimate of the quantity of greenhouse gas reductions. To do this, project developers establish an emissions baseline, which is an estimate of the scenario that would reasonably have occurred if the offset project was not undertaken. The baseline is what the project is compared against to determine the quantity of emission reductions. A baseline is always a hypothetical scenario, therefore establishing a credible baseline is critical. If the emissions baseline is overestimated, the project would claim an artificially high number of offsets, a portion of which are not real greenhouse gas reductions.

B.C. project development and approval processes

When a project is ready to be undertaken, the developer creates a project plan. This plan contains a detailed description of the proposed GHG reduction project and several baseline scenarios. The plan must also identify the selected baseline scenario, describe why it was selected and explain how the project is additional to the baseline. The plan follows a protocol — a detailed set of requirements, similar to a recipe, prescribing how emission reductions will be quantified and monitored.

They must see evidence, such as meeting minutes that show companies were factoring in the ability to earn money for emission reductions in determining the project's viability.

~ Pacific Carbon Trust CEO

The Vancouver Sun, April 21, 2012.

Under the Emission Offsets Regulation, offset projects must be validated and verified by independent, accredited third parties. The job of a validator is to ensure that the project plan follows the protocol and substantiate whether the planned GHG reductions are valid, reasonable and in compliance with B.C.'s Emission Offsets Regulation. The work of a verifier is to review the emission reductions that have taken place compared to the theoretical baseline developed in the project plan to determine the amount of offsets that have been generated. PCT relies on the work of validators and verifiers to ensure offsets are credible, only purchasing offsets from projects that have statements of assurance provided by appropriately accredited bodies.

Risks of the carbon offset market

The carbon offset market as an industry is relatively young and the concepts associated with offsets are quite complex. It involves a significant amount of scientific understanding and technical expertise. To build the integrity of this system, several international standards, such as the Verified Carbon Standard and the Clean Development Mechanism (CDM), have been developed with varying degrees of regulation and oversight. The International Organization for Standardization (ISO) has also developed offset definitions and procedures to account for GHG offset reductions. Many offset standards, including B.C.'s program, require adherence to the ISO standards. The role of the Pacific Carbon Trust is to ensure the offsets they purchase are credible.

Recent studies and audits have identified a number of risks to the assessment and quality of offsets. The CDM, established by the United Nations under the Kyoto Protocol, has developed one of the most influential carbon offset standards in the world. A 2007 report[1] looking at 93 projects registered by the CDM found that additionality was unlikely or questionable for roughly 40 percent of the projects. Furthermore, 64 percent of the projects that started before seeking offsets did not show that "the incentive from CDM was seriously considered in the decision to proceed with the project activity" even though this is a CDM requirement. Subsequently, the CDM examined a number of projects itself and temporarily suspended several organizations from validation and verification work. In 2012, the agency acknowledged that it needed to improve its standards and outcomes.

These issues are not isolated to projects approved under the CDM standards. Other offset programs have experienced similar challenges. Emission reductions that "would have happened anyway" are something the industry calls "free-riders."

The Pacific Carbon Trust is mandated to purchase offsets from projects in British Columbia that reduce greenhouse gas emissions. This can create risks around availability and quality and makes the PCT dependent on a restricted pool of projects. Given these factors, our audit included examining whether the offsets purchased met the key requirements of the Emission Offsets Regulation and the PCT's expectations. The audit also assessed whether the PCT used appropriate due diligence in their acquisitions to ensure that they only purchased credible offsets.

[1] "Is the CDM fulfilling its environmental and sustainable development objectives? An evaluation of the CDM and options for improvement". Report prepared for World Wildlife Fund, 2007.

AUDIT PURPOSE AND SCOPE

We carried out this audit to determine whether government achieved its objective of creating a carbon neutral public sector for 2010. We asked three questions:

1. Has government established reasonable procedures to allow public sector organizations to determine their greenhouse gas emissions and assessed whether they have taken sufficient actions to reduce those emissions?
2. Has the Pacific Carbon Trust purchased credible offsets?
3. Is government evaluating and reporting on the achievement of its objectives?

We developed the audit objectives using the *Greenhouse Gas Reduction Targets Act*, the Emission Offsets Regulation, Pacific Carbon Trust guidance and an understanding of the risks associated with carbon offset projects. For purposes of this audit, credible offsets are defined as offsets that are additional, conservative and real.

The audit focused on the actions of the Climate Action Secretariat and the Pacific Carbon Trust. In confirming the credibility of offsets purchased by the Pacific Carbon Trust, we also extended our work, as necessary, to obtain evidence from agencies outside of government involved with the offset projects development and approval.

We carried out our work between January and August 2012. Subsequently, we went through an extensive clearance process with a number of organizations involved in these projects. We conducted the audit in accordance with section 11(8) of the *Auditor General Act* and the standards for assurance engagements established by the Canadian Institute of Chartered Accountants.

AUDIT CONCLUSION

We concluded that the provincial government has not met its objective of achieving a carbon neutral public sector:

- Government has established reasonable procedures to allow public sector organizations to determine their greenhouse gas emissions. However, government has not yet established criteria to evaluate whether government as a whole is taking sufficient actions to reduce emissions.
- Pacific Carbon Trust has not purchased credible offsets.
- Government is reporting on its efforts to reduce emissions and its progress in achieving a carbon neutral government. However, the PCT has not provided sufficient information in its reporting about the cost and quality of its purchases.

KEY FINDINGS AND RECOMMENDATIONS

Government is determining greenhouse gas emissions but has not established criteria to evaluate whether reduction actions are sufficient

Determining emissions

In order to calculate a carbon footprint, each public sector organization needs to determine their greenhouse gas (GHG) emissions. The province's Carbon Neutral Government Regulation requires these organizations to measure specific GHG emissions related to their energy, fuel and paper consumption. Emissions are categorized into three groupings:

1. Direct emissions (referred to as scope 1) are from sources owned or controlled by the organization, such as emissions from furnaces, boilers and company vehicles.
2. Indirect emissions (scope 2), such as those arising from electricity consumption.
3. Other indirect emissions (scope 3) that are a consequence of the activities of the organization, but occur from sources not owned or controlled by it such as employee commuting, business travel, paper consumption, waste disposal and outsourced activities.

The organizations are required to determine their scope 1 and 2 emissions. The only scope 3 emissions included are those from business travel (core government only) and paper consumption.

Calculating the emissions was a significant undertaking for the organizations because they had not previously been tracking them. Each organization had to establish procedures for identifying its sources of emissions at all facilities and recording emissions data.

Our audit did not directly assess the procedures used or test emissions data, but focused on whether the Climate Action Secretariat (CAS) has provided reasonable tools and procedures for PSOs to use in calculating their emissions. We found that the CAS provides training and oversight to help ensure the data recorded is complete and accurate and there are processes in place to identify errors and omissions.

In addition to calculating emissions, public sector organizations (PSOs) must verify the accuracy of those calculations. For the 2010 reporting period, organizations certified that the emission information they submitted was correct. During this time, the Climate Action Secretariat piloted a more detailed self-certification process that included an independent verification of a sample of PSOs. The independent assessors concluded that the sample had implemented satisfactory procedures to "facilitate reasonable carbon emissions reporting". This self-verification process was expected to be rolled out to all PSOs after the conduct of our audit and should further support the reliability of the emissions data.

Actions to reduce emissions

The *Greenhouse Gas Reduction Targets Act* requires all government organizations to "pursue actions to minimize their greenhouse gas emissions" for each calendar year, beginning in 2010. It also requires these organizations to describe the actions taken by them during the year to reduce their emissions and their plans to continue doing so. See Exhibit 2 for an example of a greenhouse gas reduction initiative in the public sector.

We expected government to set clear criteria to be able to evaluate whether public sector organization's actions to reduce emissions are sufficient. We also expected government to have clear reduction targets in place against which to evaluate reduction efforts across government.

The CAS sets out the content requirements for the Carbon Neutral Action Reports and ensures that each organization submits the report to them, which they then make available on the CAS website. There is no requirement for public sector organizations to have GHG emissions reduction targets. We reviewed a sample of reports for 2010 and found that while some organizations had GHG reduction targets, most did not.

For 2011, government reported a 6 percent increase in emissions over the previous year. This increase is contrary to government's expectation to reduce GHG emissions. However, the total increase was reported as a relative reduction of approximately 3 percent when normalized for climate variability (i.e. a colder average temperature in 2011).

These factors suggest that without clear emission reduction objectives in place for public sector organizations, efforts to reduce emissions may be limited. Reduction targets can act as an incentive, encouraging organizations to substantially reduce their own GHG emissions. Otherwise, organizations may choose to purchase offsets to reduce their carbon footprint rather than invest in reduction activities.

WE RECOMMEND THAT:

The Climate Action Secretariat work with public sector organizations to ensure each is pursuing reasonable actions to reduce emissions. As part of this, government should consider establishing public sector emission reduction targets.

EXHIBIT 2: Northern Lights College

In 2011, Northern Lights College completed the Centre for Clean Energy and Technology. This LEED Platinum building will showcase water conservation and the latest "off the grid" technology for electricity production including solar and geothermal heating.

Source: Northern Lights College

The Pacific Carbon Trust has not purchased credible offsets

The provincial public sector's GHG emissions for 2010 were calculated at 814,149 tonnes[2]. In all, 128 public sector organizations provided $18.2 million to the Pacific Carbon Trust to purchase offsets on their behalf. We expected the Pacific Carbon Trust to have purchased high-quality offsets consistent with the Emission Offsets Regulation, and their own expectations.

In assessing the credibility of the offsets purchased by the PCT, we looked at two projects that together accounted for approximately 70 percent of the total offsets for 2010. One, the Darkwoods Forest Carbon Project, involved the purchase of 450,000 offsets. The other, Encana's Underbalanced Drilling Project, involved the purchase of 84,671 offsets. A description of these projects is presented in Exhibit 3.

EXHIBIT 3: Two offset projects purchased by the Pacific Carbon Trust

Darkwoods Forest Carbon project

In April 2008, the Nature Conservancy of Canada (NCC) bought a 54,792-hectare property in southeastern B.C. known as Darkwoods, with the objective of managing the land for ecological conservation. Darkwoods is an area of significant habitat for at least 19 species at risk, including grizzly bear and endangered mountain caribou.

The project plan states that the property was "under immediate threat of liquidation logging" by a market-driven acquirer. This became the hypothetical baseline scenario for the project. Under this scenario, the project expected to achieve GHG emission reductions by avoiding the release of carbon associated with aggressive logging practices. The NCC claimed that carbon finance would help it overcome financial obstacles, allowing them to implement the project. The Darkwoods project was developed, validated and verified under the Verified Carbon Standard.

Source: Canadian Geographic

[2] Of this total, 84, 367 tonnes do not require offsetting under the Carbon Neutral Government Regulation. As per the regulation, some of the emissions reported in the total do not require the purchase of offsets in order to reach carbon neutrality. This includes emissions from mobile or stationary combustion of biomass as well as emissions from school buses and BC Transit buses.

EXHIBIT 3 (CONTINUED): Two offset projects purchased by the Pacific Carbon Trust

Encana Underbalanced Drilling project
This carbon project, located near Fort Nelson, B.C., was developed by Encana Corporation and resulted in emission reductions from reduced gas flaring. The project used an existing technique known as underbalanced drilling, but with natural gas used as the drilling lubricant instead of nitrogen. This natural gas was conserved through on-site recovery and capture, and then streamed directly into a pipeline, eliminating the need for flaring. Encana claimed that carbon finance would help overcome technological obstacles, allowing them to implement the project. The Encana project was developed under the Pacific Carbon Trust Standard, meaning it was validated and verified against the requirements of the Emission Offsets Regulation.

Source: Encana Corporation

Project eligibility concerns

We expected the Pacific Carbon Trust to ensure it only purchased offsets that met the additionality criteria of the Emission Offsets Regulation (EOR) and the PCT's expectations. This includes ensuring that the proponents considered and included the value of developing offsets as part of the justification for going ahead with the project. This is a stated expectation of the PCT and is consistent with EOR and good practice. Carbon experts also confirmed this to be an important expectation.

We found that both projects started without showing that the value of offsets was considered to the extent that it provided the incentive for going ahead. Offsets are supposed to be the tipping point to make a project happen.

- The Nature Conservancy of Canada (NCC) decided to purchase the Darkwoods property in 2006, but the transaction did not close until April 1, 2008 (Exhibit 4). For the NCC, offsets were not a critical factor in the decision to acquire the Darkwoods property. A carbon offsets feasibility study was not completed until January 2009. The NCC did not approach the Pacific Carbon Trust about offsets until late 2009.
- In the case of Encana's underbalanced drilling project, the company started the project in 2008 and had already successfully completed many wells by the time they met with the Pacific Carbon Trust in August 2009 (Exhibit 4). We found that carbon credits were not part of the decision to proceed with the project.

The project baselines were not properly determined

Even if the projects had considered the value of offsets, they would still be problematic because of their flawed baselines. The baseline scenario is a hypothetical representation of what would reasonably be expected to have occurred in the project's absence. Section 3(2)(j) of the Emission Offsets Regulation requires baselines to result in a conservative estimate of the GHG reduction by considering legal requirements and any other factors needed to support the selected baseline. We expected projects purchased by the Pacific Carbon Trust to demonstrate that the baseline met these requirements. We found that both projects had problems satisfying these baseline requirements.

Neither project had a baseline scenario that could be supported. The Darkwoods baseline was not conservative and did not recognize the legal constraints on the project area. The Encana baseline was not supported by an appropriate test to show it was the most likely scenario.

Darkwoods baseline determination

We found the baseline assumptions in this project were not conservative and resulted in a baseline far above what would likely have occurred had common practice been reasonably established. We also found that the NCC's potential harvesting activities are significantly constrained by a legal obligation to conserve the land, thereby limiting the baseline options available to the NCC.

EXHIBIT 4: Darkwoods and Encana timeline of activities

The Darkwoods and Encana projects were underway before seeking offset credits.

NCC = NATURE CONSERVANCY OF CANADA; PCT = PACIFIC CARBON TRUST

DARKWOODS

2005

JUNE 2005
Darkwoods property put up for sale.

2006

EARLY 2006
The Nature Conservancy of Canada (NCC) makes an offer to purchase Darkwoods

2007

AUGUST 2007
Initial property appraisal for Ecological Gifts Program

NOVEMBER 29, 2007
Offset projects must start after this date

2008

MARCH 2008
PCT is incorporated

APRIL 2008
NCC acquires Darkwoods property (project start date)

2009

JANUARY 2009
Carbon offset project feasibility study

OCTOBER 2009
PCT has first discussions with NCC about the project

2010

OCTOBER 2010
Offset purchase agreement signed

2011

APRIL 2011
Project protocol approved, project validated, project verified

ENCANA

APRIL 2008
Encana project start date

AUGUST 2009
PCT has first discussions with Encana about the project

NOVEMBER 2010
Project protocol approved by PCT, project validated

DECEMBER 2010
Offset purchase agreement signed

JANUARY 2011
Project verified

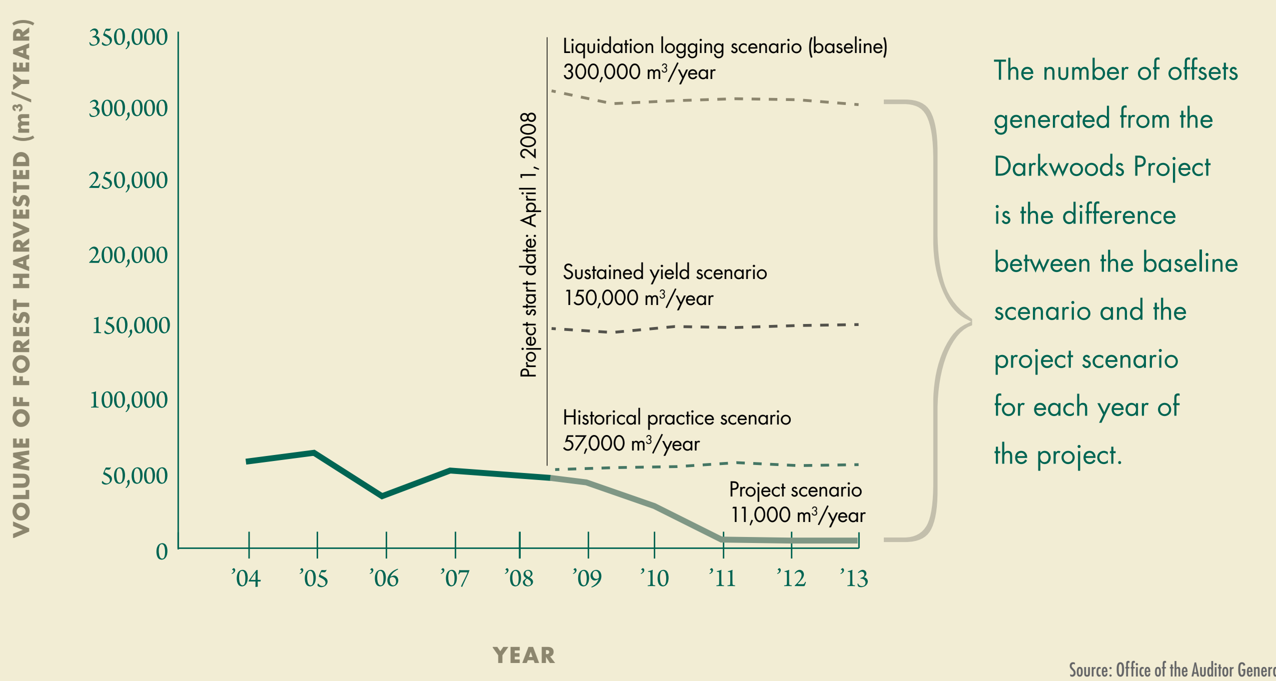
Source: Office of the Auditor General

Baseline assumptions not conservative
The Darkwoods project was designed under the assumption that if the Nature Conservancy of Canada had not purchased the property, the most likely owner would have been a liquidation harvester, who would purchase the property to generate the "maximum financial return" "with little regard for environmental protections." Following this scenario, the project expected to achieve GHG emission reductions by avoiding the release of carbon associated with aggressive logging practices. Other alternative baselines presented in the project plan included a sustained yield harvesting scenario, and the previous owner's historical practice which involved limited annual harvesting.

The selected baseline (liquidation logging), as well as the other options available to the project developer, is shown in Exhibit 5.

Darkwoods Photo: Bruce Kirby

EXHIBIT 5: Comparison of harvesting volumes in potential baseline scenarios developed for the Darkwoods project



Source: Office of the Auditor General

However, we found limited support for a “liquidation logger” scenario: no such companies bid on the property, and it was widely reported at the time of sale that the owner’s preference was to sell to a buyer who would appreciate or maintain the area’s forest and wildlife values. Our assessment is that a logging company, certified to one of three internationally recognized forest certifications, would be the most likely alternative purchaser of the Darkwoods property. Most logging companies in the province are certified and sawmills in this region are also certified. Such certification requires forestry practices to reflect key values (see sidebar). Forest companies that do not preserve environmentally sensitive areas can face public pressure to do so. As such, an alternative owner would likely have followed sustainable forestry practices as opposed to the unsustainable practices assumed in the selected baseline.

The project assumed a “liquidation logger” would not follow the requirements of the *Private Managed Forest Land Act* (PMFLA), even though the project plan identified that most private forest land owners in the area followed these requirements. This is common practice in the area, as significant tax benefits are gained by registering a forest under the Act. The project documentation provided no explanation for omitting such registration from the baseline calculation. By not registering under the PMFLA, a liquidation owner would not follow the minimum forest management objectives for private land (e.g. for soil conservation, protection of water quality, fish habitat and critical wildlife habitat, and reforestation). The baseline assumed that areas classified as environmentally protected by the previous owner such as sensitive habitat for mountain caribou and other at-risk species, would be logged, and not replanted by a liquidation owner.

We found that aggressive assumptions around the harvesting practices under the baseline scenario resulted in 30 percent more harvestable wood than was projected in the timber appraisal used for establishing the property purchase price. This resulted in overestimating the emission reductions and in overstating the carbon offsets generated by the project.

Darkwoods Photo: Bruce Kirby

FORESTRY PRACTICES IN THE KOOTENAY REGION

The Sustainable Forestry Initiative (SFI) is a globally recognized standard that covers key values such as protection of biodiversity, species-at-risk, wildlife habitat and water quality, as well as sustainable harvest levels and prompt regeneration. For example, one company located in Creston, B.C., issued a guide for timber producers encouraging adherenceto the SFI program and including the statement that its mill will not purchase timber from unknown sources or producers whose practices are illegal or do not meet regulations for private land management.

The sustained yield scenario considered by the project was the closest to following the requirements of the PMFLA but was not selected as the most likely option. While this scenario would have resulted in significantly lower harvest levels and fewer offsets (see Exhibit 5), even this scenario is not the most likely baseline. Baselines are required to meet any legal obligations on the project area. For the Darkwoods project, significant legal constraints on harvesting were not accounted for in the project plan.

The Nature Conservancy of Canada had a legal obligation to conserve the property

The Nature Conservancy of Canada acquired the Darkwoods property using a Natural Areas Conservation Program grant of $25 million and a donation of a major portion of the property through the federal **Ecological Gifts Program** (see sidebar). These two sources accounted for the majority of the property's purchase price of approximately $100 million. Under the Ecological Gifts Program, the Nature Conservancy of Canada becomes legally obligated at the time of purchase to manage these lands for conservation.

To stay within their legal obligations, the NCC is restricted to a minimal harvest required to maintain ecological values and the health of the forest. With such a minimal amount of harvesting available to the NCC, the project baseline should have been no greater than the historical practice.

Encana baseline determination

Encana developed its own protocol for the proposed **underbalanced drilling** project. This protocol was approved by the Pacific Carbon Trust, although the EOR does not give such approval authority to the PCT. We found that the protocol included an inappropriate process to determine the baseline. In the protocol, the baseline is defined as historical practice – gas flaring. This approach is inconsistent with EOR and ISO expectations for establishing a baseline, which require a test to select the baseline from several potential scenarios. This limitation allowed Encana to avoid conducting a financial test to determine whether the project was more financially attractive than the baseline scenario.

UNDERBALANCED DRILLING is a procedure used to drill gas wells where the pressure in the wellbore is kept lower than the pressure in the formation being drilled. As the well is being drilled, formation gas flows into the wellbore and up to the surface. Historically, this gas has been flared, as venting has more serious atmospheric impacts. Commercially available technology allows this gas to be captured and sold into the pipeline.

THE ECOLOGICAL GIFTS PROGRAM

This federal government program allows Canadians who own ecologically sensitive land to ensure its protection through tax benefits to land owners who donate land to a qualified recipient. For an "ecogift" to meet the requirements of the program, the federal Environment Minister must certify that the land is ecologically sensitive, approve the recipient to receive the gift, and certify the fair market value of the donation. The donor receives a tax receipt for the full value of the ecogift. The land recipient must then ensure that the land's biodiversity and environmental heritage are conserved in perpetuity.

When a carbon offset project involves revenue, good practice typically requires a financial analysis test to show that the proposed project is not the most attractive course of action.

We expected Encana to have considered the financial benefits of this project, to ensure this project could not be considered business-as-usual.

Encana Photo: Encana Corporation

Instead, we found that Encana did not assess the financial implications of the project. Based on the preliminary information provided to the PCT on the project costs and gas recovery levels, the project was projected to be more economical than the historical practice of flaring the gas. The project had the potential to provide a significant financial return on the incremental project costs. Actual results confirm the projections: the company providing the technology reported that the gas conserved over the course of the project had a market value of more than $7 million. This is substantially greater than the projected incremental cost of the technology. Gas valued at more than $3 million was still flared because the compressors employed had insufficient capacity for the stronger gas flows.

Despite the lack of financial information, the Pacific Carbon Trust purchased offsets from the Encana project. As the only offset purchaser of this project, the PCT could have directed Encana to use specific tests. The PCT is able to select projects based on their own requirements (as long as these do not contradict the requirements of the B.C. Emission Offsets Regulation). Knowing that revenues were a highly relevant factor in this proposal, the PCT should have pursued a financial analysis by Encana.

The Climate Action Secretariat supports the PCT in creating their own purchase requirements, and the CAS has indicated that offsets should not pay companies to do what they had a solid business case to do already. Encana's project does not pass this test.

Why this happened

The intentions of the Emission Offsets Regulation have not been clearly defined

The Emission Offsets Regulation (EOR) provides the regulatory framework for offset projects but is designed to not be overly prescriptive. Government has intentionally placed reliance on the expertise of third parties to interpret the regulation during their validation and verification work.

These third parties are required to assess the projects against the regulation and applicable ISO standards—both include language that allows for considerable flexibility and judgment.

While professional judgment is necessary to evaluate these projects, government's intention was that guidance would be created to supplement the regulation and provide clarity where appropriate. For example, the EOR does not provide any requirements regarding quantification protocols that are developed by proponents. As there were no "government approved" protocols when the regulation was created, proponents created their own protocol or adapted a protocol developed under a different standard.

We expected to find clear guidance for proponents in key risk areas such as additionality and protocol development. Instead, we found that while the PCT had developed "draft" guidance documents, proponents are not required to adhere to this guidance, and it does not sufficiently address key risk areas such as those identified in this audit. We also found that there is currently limited guidance for protocol development and approval. Over the course of the audit, the PCT acknowledged that gaps exist between EOR and a fully functioning greenhouse gas program regarding protocol development and approval. The PCT has acknowledged that defining these protocol requirements will increase the credibility of the program, streamline the process of approving projects, expand the scope of the GHG program, provide greater certainty for project developers, and outline criteria for validation bodies to validate against.

WE RECOMMEND THAT:

The Climate Action Secretariat ensure supplementary guidance to the Emission Offsets Regulation be finalized and adhered to.

Due diligence concerns were not satisfactorily addressed

The carbon offset market has been referred to in literature as lacking the critical competitive check found in well-functioning markets, in which the interests of buyer and seller are naturally balanced against each other. In offset markets, both the buyer and seller benefit from maximizing the number of offsets a project generates:

- Sellers have a financial incentive to overestimate the baseline scenario—artificially inflating emission credits to increase profitability.
- Buyers seeking offsets as part of a carbon reduction requirement are inclined to focus more on the volume of available offsets rather than their quality.

This was particularly relevant for the Darkwoods project as one of the project developers had a contract with the NCC to purchase offsets from the project it was helping to develop. The project developer also helped develop the protocol for the Darkwoods project. Similarly, the validator was involved in the initial feasibility study, protocol approval and project validation. In such circumstances, potential purchasers should exercise enhanced due diligence and risk management.

> Because commercial exploitation was the counterfactual used to justify the Nature Conservancy of Canada (NCC) carbon offsets, offsets were subsequently sold to non-arms-length buyers, and numbers of carbon offsets are highly sensitive to assumptions, one can only conclude that the carbon offsets generated by this (and probably many other) forest conservation projects are simply spurious.

Source: G. Cornelis van Kooten, Tim Bogle, Frans P. de Vries, "Rent Seeking and the Smoke and Mirrors Game in the Creation of Forest Sector Carbon Credits: An example from British Columbia," 2012, p 1.

The two projects, Darkwoods and Encana, were among the first with which the Pacific Carbon Trust was involved. For assistance with these projects, the trust hired consultants to review certain key aspects of the projects and identify issues related to their credibility. This due diligence appeared to be a valuable component of the review, bringing several significant issues to the trust's attention.

We found the concerns raised by these consultants to be valid, but noted that many were not satisfactorily addressed by the PCT before purchasing the offsets. The PCT's due diligence lacked the necessary rigour. Overall, the Pacific Carbon Trust was not a prudent purchaser.

For example, due diligence comments on the Darkwoods project included an assessment that the baseline represented "rape and pillage" of the forest, rating a "3 out of 10 for conservativeness." It also stated that "even the most aggressive forest practices would not be able to log every hectare identified as operable on the landbase" – yet no changes were made to address these concerns. As described in an earlier section, we had similar concerns with the realism of the baseline.

The Pacific Carbon Trust's guidance material recognizes that skepticism and common sense should be used when evaluating a baseline. The guidance also acknowledges that "rules-based approaches can encourage 'gamesmanship' with the interpretation of the rules."

We concluded that the problems in these projects were primarily rooted in a lack of skepticism and common sense being applied by the PCT. The Pacific Carbon Trust's main concern seemed to be with justifying that rules were adhered to, and less in assessing whether the results made sense.

WE RECOMMEND THAT:

The Pacific Carbon Trust, to better manage offset purchase risks, ensure that the results of its due diligence efforts are satisfactorily analyzed, concluded and documented.

The Climate Action Secretariat did not provide sufficient oversight

The Pacific Carbon Trust's mandate to build the carbon industry in B.C. creates a tension with its mandate to purchase credible offsets. The governance arrangements applied to purchase offsets currently run counter to good practice. The Climate Action Secretariat (CAS) is the agency designated by legislation to regulate offsets. We found that, because it has not considered the efficacy of the credits purchased by the PCT, the CAS has effectively delegated this work to the PCT. Consequently, the PCT acts as a regulator and buyer in the market place. We found that the PCT has not been diligent in its purchase of credible offsets. The Climate Action Secretariat should be more active in developing guidance and assessing the PCT's offset purchases to ensure they meet government's intention of achieving carbon neutrality.

WE RECOMMEND THAT:

The Climate Action Secretariat provide stronger oversight to ensure that the offsets purchased on behalf of government are credible.

Government and the Pacific Carbon Trust report on their achievements, but improvements could be made

Public sector organizations are required to report to the Climate Action Secretariat on their GHG emissions as well as the actions they have taken to minimize those emissions. The organizations fulfill this requirement by submitting a Carbon Neutral Action Report. From these, the Climate Action Secretariat summarizes government's overall performance in a report titled *Carbon Neutral B.C.* The first of these reports was issued in July 2011. It was the first year the provincial government was required to measure and report its GHG emissions, and it established 2010 as a baseline year. In July 2012, government reported its 2011 GHG emissions.

We expected government to be evaluating and reporting on the achievement of its objective of carbon neutrality. We also expected this reporting to include the costs and benefits of reducing emissions and of offsetting the remainder, providing government with an opportunity to evaluate its success towards achieving the outcome of carbon neutrality.

Requiring the province's public sector organizations to identify, quantify and report their emissions was a significant challenge for organizations. Before this, GHG consumption was not something the public sector calculated. Nevertheless, we found that government reported on actions taken to reduce emissions, as well as reporting on the total emissions generated, the emissions required to be offset and the offsets purchased. The emissions for 2010 and 2011 are presented in Exhibit 6. The total increase was reported as a relative reduction of approximately 3 percent when normalized for climate variability (i.e. a colder average temperature in 2011).

EXHIBIT 6: Greenhouse gas emissions in British Columbia's public sector, 2010 and 2011

ORGANIZATION	2010 EMISSIONS (TONNES)	2011 EMISSIONS (TONNES)	INCREASE
Core government	92,951	96,678	4%
Crown corporations	92,245	96,817	5%
Health authorities	217,135	231,472	7%
Post-secondary	150,779	159,207	6%
School districts	176,672	191,335	8%
Public sector total	**729,782**	**775,509**	**6%**

Source: *Carbon Neutral B.C.* reports

Although the reports highlight specific work taking place across the public service, they did not sufficiently address the risks facing public sector organizations in their continued work towards reducing GHG emissions, nor did the reports discuss key barriers to continued improvement.

We also found that while the Pacific Carbon Trust did report its offset portfolio (including the name of the project, validator and verifier), the reporting lacked details needed to demonstrate the cost-effectiveness of the offsets purchased.

Reporting on value-for-money

An important aspect of transparent reporting for the Pacific Carbon Trust is to demonstrate how funds spent on behalf of the public sector reflect good value-for-money. The Pacific Carbon Trust recognizes that this is an important part of managing public sector costs and identifies "providing cost-effective offsets" as a way to achieve its mandate. In this regard, we noted that the Pacific Carbon Trust's annual reporting only states that it pays, on average, less than $25 per tonne (a target tied to the current price that public sector clients pay to offset their emissions). This measurement is too broad to be of any value – the average cost could be anywhere from $1 to $24, which represent very different views of the PCT's purchasing practices. Greater transparency should be provided, as well as an analysis or comparison to the wider marketplace.

The PCT is restricted to purchasing offsets generated in B.C. It had challenges demonstrating value-for-money in its purchases. For the projects examined in this audit, we found that the Pacific Carbon Trust had to pay more than market rates for both.

Darkwoods offsets costs

The Pacific Carbon Trust paid $4.5 million for 450,000 Darkwoods offsets ($10 per offset), while one of the project's developers paid $1.5 million for 250,000 offsets ($6 per offset). The Pacific Carbon Trust suggested it paid more because the project developer would have negotiated a lower price. This type of arrangement highlights the conflicts of interest inherent in carbon markets as a result of financial incentives for those involved with developing carbon projects. Compared to the wider marketplace, the Pacific Carbon Trust paid about 80 percent more than the average global price ($5.49) for all forestry projects and more than double the average price ($4.61) for projects in regulated markets.

The Pacific Carbon Trust's contract with the Nature Conservancy of Canada was based on escalating prices, meaning the Pacific Carbon Trust paid more for a higher volume of offsets. Had it bought 250,000 or fewer offsets, it would have only paid $8 for each one. The PCT explained that they were uncertain whether they could acquire the significant volume of offsets necessary to meet government's carbon neutral goal and were therefore dependent on Darkwoods as the offset supply in B.C. was not extensive.

The Pacific Carbon Trust cited the need to provide incentives for projects to deliver higher volumes. As a result, the PCT was willing to pay more to encourage larger volumes be delivered by the Darkwoods project developers.

The value-for-money aspect of the Pacific Carbon Trust's approach was further eroded as a result of the agency having bought more offsets than needed from the Darkwoods project. This was a result of the project's "leakage" not being conservatively estimated. The leakage factor reduces the amount of offsets available from a project (see sidebar). The PCT told us that it was not satisfied with the leakage factor calculated for the Darkwoods project, because the amount was much lower than pending provincial standards at the time on this issue. It was also lower than the amount estimated as being appropriate in a study of Pacific Northwest forests.

LEAKAGE

"Leakage" is a complex issue. However, in simple terms it refers to what happens when an offset project causes an increase in GHG emissions at another location. For example, if a project reduces harvesting in the project area, it is possible that demand for forest products could push logging operations to another location thus negating GHG reductions in the original location.

Because the Pacific Carbon Trust was unable to negotiate a higher leakage factor, it purchased 450,000 offsets instead of the required 403,112 Darkwoods offsets at an additional cost of $468,880.

Encana offsets costs

The contract with Encana provided for varying prices depending on the amount purchased. The Pacific Carbon Trust paid $20 per offset for the first 47,000 and $18 per offset for the balance. In all, the trust purchased 84,671 offsets (most of which were applied to the 2010 carbon neutral year) for over $1.6 million. The average price in the voluntary carbon market at this time was about $10 per offset for similar types of projects.

As the project developed, Encana became concerned about whether the Pacific Carbon Trust would follow through on the purchase agreement. To provide some level of security, the Pacific Carbon Trust agreed to a $30,000 penalty provision, calling for the PCT to pay Encana's project development costs if it did not complete the transaction. In our view, this provision raises questions about the Pacific Carbon Trust's ability to be objective when it assessed the quality of the Encana project.

WE RECOMMEND THAT:

The Pacific Carbon Trust provide greater transparency about the cost-effectiveness of its purchases.

The Climate Action Secretariat and the Pacific Carbon Trust ensure that reporting on carbon neutrality assesses the trade-offs between reducing government emissions and offsetting those emissions through the purchase of offsets.

LOOKING AHEAD

We will follow up on the implementation status of the recommendations in our April 2014 follow-up report. Given the nature of the findings in this report, we will consider examining other offset projects such as the Great Bear Rainforest project. The credibility of offsets is imperative if the expected environmental benefits are to be realized.

Source: Office of the Auditor General

Many organizations are already voluntarily reducing their emissions and some are following government in becoming carbon neutral. However, purchases of carbon offsets alone will not lead to government meeting its climate change objectives for the province. Government has a goal of a 33 percent carbon emissions reduction by 2020. A comprehensive suite of policies and programs will need to be implemented to meet this goal. We will consider examining the effectiveness of plans and programs focused on that goal.

Even if the provincial emissions reduction goal is being attained, climate change will still have impacts on our economy and society. All levels of government will need to understand these impacts and implement appropriate adaptation measures to reduce the risks. This also is an area that we will look into for future audit work.

APPENDIX 1: DEFINITIONS OF ADDITIONALITY

While there are a number of definitions of additionality, they all focus on the need for showing that offset benefits were a serious consideration in the decision to implement the project. Offsets are meant to be the tipping point to make projects happen.

The Pacific Carbon Trust - news release, May 5, 2011

Real GHG reductions or removal that would not have occurred without the revenues associated with the purchase of offsets.

Clean Development Mechanism

The CDM Executive Board deems a project additional if its proponents can document that realistic alternative scenarios to the proposed project would be more economically attractive or that the project faces barriers that CDM helps it overcome.

Climate Action Reserve program manual

GHG reductions must be additional to any that would have occurred in the absence of the Climate Action Reserve, or of a market for GHG reductions generally. "Business as usual" reductions – i.e., those that would occur in the absence of a GHG reduction market – should not be eligible for registration.

Climate Action Reserve

Means that the emission reduction is not required by law and would not have occurred but for the incentive provided by the carbon market. President CAR, June 29, 2011.

Electric Power Research Institute

A GHG emission reduction project designed to create offsets is considered to be "additional" if the reductions created by the project activity would not have occurred but for the implementation of the project and the incentives created by the offset program.

Offset Quality Initiative

The revenue from the project's emission reductions should be reasonably expected to have incentivized the project's implementation for an offset project to be considered additional.

Pembina Institute and the David Suzuki Foundation

To be additional, an offset project must not have happened without the incentives arising from the offset market.

Stockholm Environment Institute

Would the project have happened anyway? If the answer to that question is yes, the project is not additional.

UK Department of Energy and Climate Change

Projects must demonstrate that they produced a saving in carbon that would not have happened otherwise i.e. the project could not take place without the carbon finance from selling credits.

U.S. Government Accountability Office (GAO)

An offset is additional if it would not have occurred without the incentives provided by the offset program.

APPENDIX 2: GLOSSARY

Additionality:
The principle that only those projects that would not have happened anyway should be eligible for carbon credits. Additional emission reductions are those emission reductions that would not have occurred under business-as-usual or in the absence of actions associated with an offset project. Pacific Carbon Trust requires proponents to demonstrate that the incentive of having project emission reductions recognized as offsets helps the project overcome, or partially overcome, obstacles to carrying out the project. See Appendix 1.

Baseline scenario:
A scenario that reasonably represents the emissions by sources of greenhouse gases (GHGs) that would occur in the absence of the proposed project activity.

Carbon Dioxide (CO_2):
This greenhouse gas is the largest contributor to human-induced climate change. For example, CO_2 is emitted by deforestation and the burning of fossil fuels.

Carbon Dioxide Equivalent (CO_2e):
A measure of the global warming potential of a particular greenhouse gas compared to that of carbon dioxide. One unit of a gas with a CO_2e rating of 21, for example, would have the warming effect of 21 units of carbon dioxide emissions (over a time frame of 100 years).

Carbon offset:
A carbon offset represents a reduction or sequestration of greenhouse gas emissions generated by activities – such as improved energy efficiency – that can be used to compensate for, or offset, the emissions from another source, such as a plane trip. One carbon offset represents the reduction of one tonne of carbon dioxide (or its equivalent in other GHGs).

Carbon neutral:
The concept of achieving carbon neutrality involves purchasing carbon offsets for any emissions generated to achieve net-zero greenhouse gas (GHG) emissions.

Conservative:
A principle or set of practices designed to avoid overestimating emissions reductions. In the Emission Offsets Regulation the term "conservative" is used to mean a GHG reduction that is unlikely to have been overestimated.

Greenhouse Gases (GHGs):
Gases that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the earth's surface, the atmosphere and clouds. For purposes of *Greenhouse Gas Reduction Targets Act* (GGRTA), greenhouse gases are limited to the six main GHGs whose emissions are human-caused: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6).

APPENDIX 2: GLOSSARY

Greenhouse Gas Reduction:
For the purposes of the Emission Offsets Regulation, the definition is a reduction of GHG emissions or an enhancement of GHG removals.

Kyoto Protocol:
An international treaty that requires participating countries to reduce their emissions by 5 percent below 1990 levels by 2012. The Protocol, developed in 1997, is administered by the Secretariat of the UN Framework Convention on Climate Change.

Leakage:
Leakage is defined as the net change of human-caused emissions by sources of greenhouse gases (GHGs) which occurs outside the project boundary, and which is measurable and attributable to the project activity.

Offset Project:
A discrete action undertaken to achieve a GHG reduction (Emission Offsets Regulation definition), which includes both enhancement of GHG removals and reductions in emissions.

Project Plan:
Plan prepared by or on behalf of a Proponent and in accordance with Sections 3 or 7 of the Emission Offsets Regulation.

Project Protocol:
A document that provides specific principles, concepts, and methods for quantifying, monitoring and reporting GHG reductions for a project.

Proponent:
Person who proposes either to carry out or to engage another person to carry out a project to generate emission offsets for the purposes of the Act.

Regulated Market:
The market for carbon credits used to reach emissions targets under the Kyoto Protocol or the European Union Emissions Trading Scheme (EU ETS). Also called the Compliance Market.

Validation:
An initial assessment of an offset project against a set of criteria. Under the Emission Offsets Regulation this is established through assurance by an independent, ISO 14065 accredited firm or organization that the content and assertions of the Project Plan comply with the requirements of the regulation.

Verification:
In the context of reductions associated with an offset project, verification is the assessment and confirmation that the claimed reductions have occurred. Under the Emission Offsets Regulation this is established through assurance by an independent, ISO 14065 accredited firm or organization.

Voluntary Market:
The non-regulated market for carbon credits that operates independently from Kyoto and the EU ETS. Also called the Non-Regulated Market.

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Mountain Caribou cover photo courtesy of G. Beaudry.

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forest management

Forest Carbon Offsets Revisited: Shedding Light on Darkwoods

Gerrit Cornelis van Kooten, Timothy N. Bogle, and Frans P. de Vries

This paper investigates the viability of carbon offset credits created through forest conservation and preservation. A detailed forest management model based on a case study of a forest estate in southeastern British Columbia, owned by The Nature Conservancy of Canada (NCC) is used to demonstrate the challenging nature of estimating forest carbon offsets. For example, the NCC management plan creates substantial carbon offset credits because the counterfactual is that of a private forest liquidator, but when sustainable management of the site is assumed, the commercial operator would sequester much more carbon than under the NCC plan. The broader message is that the creation of carbon offsets is highly sensitive to ex ante assumptions and whether physical carbon is discounted. We demonstrate that more carbon gets stored in wood products as the discount rate on carbon rises (addressing climate change is more urgent). A high discount rate on carbon favors greater harvests and processing of biomass into products, while a low rate favors reduced harvest intensity. Further, since carbon credits earned by protecting forests may find their way onto world carbon markets, they lower the costs of emitting CO_2 while contributing little to mitigating climate change.

Keywords: forest management, carbon flux, discounting physical carbon, climate change

In the face of global warming, climate mitigation strategies that enhance carbon sequestration in ecosystems are becoming increasingly important. It makes intuitive sense to take account of carbon offsets generated by projects that promote tree growth or otherwise cause more carbon to be stored in ecosystems, including those that enhance soil organic carbon (IPCC 2000). Five categories of forest offset projects can be identified (Malmsheimer et al. 2011): (1) afforestation (planting trees where none existed previously); (2) reforestation (regenerating previously forested sites); (3) forest management (management of existing forests to achieve specific carbon uptake objectives while maintaining forest productivity); (4) forest conservation (managing existing forests to prevent their conversion to other uses); and (5) forest preservation (managing forests to prevent their deterioration or degradation). Although forest conservation and preservation are currently not eligible for emission reduction (or carbon) offsets, concerns about tropical deforestation have led many to commend their use in developing countries as a tool for addressing global warming (Kaimowitz 2008, Buttoud 2012). Indeed, forest conservation and preservation projects are increasingly considered alternative means for earning certified emission reduction (CER) credits under the rubric of reducing emissions from deforestation and forest degradation, or REDD (Law et al. 2012).

In this paper, we contribute to the emerging literature on these forms of forest offset credits by addressing the following question: What are the implications for reducing atmospheric CO_2 if carbon offsets from forest protection projects are used in lieu of emissions reduction? To answer this question, we examine the role of a particular forest preservation project in creating carbon offset credits, focusing on the procedures used to determine the extent of carbon offset creation (including identification of counterfactuals) and, more generally, the challenges of measuring the corresponding impact on carbon sequestration in forests.

Background

It may be helpful to recall that the European Union originally opposed the use of carbon sequestration as a means for countries to meet their greenhouse gas emission reduction targets under the Kyoto Protocol of the United Nations' Framework Convention on Climate Change (UN FCCC). Yet, after the United States withdrew from the Kyoto negotiations following the Sixth Conference of the Parties (COP6) to the UN FCCC in The Hague, the Kyoto signatories agreed at COP7 in Marrakech to permit carbon uptake from

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This article uses metric units; the applicable conversion factors are: meters (m): 1 m = 3.3 ft; cubic meters (m^3): 1 m^3 = 35.3 ft^3; kilometers (km): 1 km = 0.6 mi; hectares (ha): 1 ha = 2.47 ac.

land use, land-use change, and forestry (LULUCF) activities in lieu of greenhouse gas emissions in meeting targets but only for the first Kyoto commitment period (2008–2012). More specifically, the November 2001 Marrakech Accord permitted carbon sequestration in trees planted as a result of an afforestation or reforestation program to be counted as a credit but also required carbon lost by deforestation to be debited (Article 3.3).

While only carbon sequestered in wood biomass was counted under Marrakech, it still left open the possibility for including such components as soil and wood product carbon sinks and wetlands that store methane (Article 3.4). CO_2 offset credits could also be obtained for activities in developing countries under Kyoto's Clean Development Mechanism (CDM), which enables private companies and industrialized nations to purchase (certified) offsets from developing countries by sponsoring projects that reduce CO_2 emissions below business-as-usual levels in those countries. As a result, there are strict guidelines regarding projects to establish or re-establish plantation forests in developing countries under CDM, which has made it difficult for such projects to overcome the hurdles for acceptance (van Kooten et al. 2009). A more troublesome aspect relates to the role of forest conservation and preservation activities.

An emerging number of studies have assessed the economic functioning of carbon offset policies. A key issue relates to the extent to which projects would have been undertaken anyway, something known as "additionality." Mason and Plantinga (2013) argue that the problem of additionality is inherently downplayed or ignored as a result of asymmetric information; sellers of carbon offsets possess information about the opportunity costs of offset projects that is not available to buyers. This results in the sale of offsets, particularly in voluntary markets, at prices that do not reflect true opportunity costs of mitigating CO_2 emissions. For example, Millard-Ball (2013) finds that in the transportation sector many offsets are not additional, primarily due to uncertainty surrounding estimates of business-as-usual emissions.

In a systematic account of offset policies, Hahn and Richards (2013) argue that offset programs have the potential to reduce the costs of achieving environmental targets but that in practice this is difficult to establish due to the complex nature of market design. In addition to the difficulty of setting appropriate baselines (counterfactuals), Hahn and Richards (2013) also highlight problems related to units of measurement, monitoring requirements, and the process of certifying offset credits. Overall, the problem is that a wider array of options for trading alternative sequestration services typically increases the complexity of the market, primarily as a consequence of such dynamic complications (see Wilman and Mahendrarajah 2004).

A special task force of the United States' organization of professional foresters (Society of Foresters) charged with investigating forest carbon offsets takes a similar view: "Offset projects are highly variable and depend on numerous assumptions, most of which are susceptible to bias and 'virtually insurmountable' measurement errors" (Malmsheimer et al. 2011, Oliver 2013). It points out that one of the main problems with forest carbon offset credits appears to be the misguided belief that an unmanaged forest will accumulate and retain an amount of carbon greater than what the offset buyer is emitting over time—a false sense that, on purchasing offsets, a buyer's activity is carbon neutral. Further, it concludes that the global benefits of forest offsets are overstated due to additionality. Finally, there is a general failure to account for leakage—that harvest takes place elsewhere when a forest is protected; indeed, the task force points to econometric evidence suggesting that leakage is often close to 100% (Malmsheimer et al. 2011).

The international community is currently engaged in deliberations concerning whether the UN FCCC's Kyoto process ought to certify forest conservation and preservation projects under the CDM (Bosetti and Rose 2011). Sathaye et al. (2011) indicate that the cobenefits of such projects—the noncarbon benefits—amount to between 57.5 and 76.5% of the total protection benefits, while Rose and Sohngen (2011) argue that Kyoto's current focus on afforestation leads to a decline in the global carbon stored in ecosystems. However, they suggest that, although not ideal compared to immediate implementation of a tax/subsidy scheme for emissions/uptake of CO_2, the initial loss can be overcome by crediting avoidance of deforestation in the future. Bosetti et al. (2011) report that greater reliance on reduced deforestation and other land-use activities could reduce the net costs of achieving a global target of 550 parts CO_2 per million by volume in the atmosphere by upwards of $2 trillion. These results are based on output from climate models, and assume that a new climate agreement will be struck and administered under ideal global governance, which is an ideal that the current study disputes.

In the meantime, forest conservation and preservation projects play a large role in the voluntary emission reductions (VERs) market, a market that amounted to $424 million in 2010, with trades averaging $3.24 tCO_2^{-1} in 2010, down from a high of $5.81 tCO_2^{-1} in 2008 (Peters-Stanley et al. 2011). This compares to a total global carbon market estimated to be worth €92 billion (approximately $125 billion) in 2011, an increase of 10% over 2010. There is the suggestion, however, that VERs affect not only the voluntary market but also compliance markets, most notably the EU's Emission Trading System (EU ETS) (e.g., see Peters-Stanley et al. 2011).[1] Thus, while CER credits created by forest conservation and preservation activities are currently not available for sale in international markets, VER offsets created in this way are marketed in global carbon markets.

When carbon offsets can be created by changing land management practices, the supply of ecosystem services or other cobenefits can be financed from the sale of such offsets, thereby creating enhanced incentives for landowners to increase other services from the land, such as biodiversity. We show that this multimarket interaction creates incentives for rent seeking, thereby highlighting the difficulty of establishing claims related to forest offset credits. Rent seeking occurs because economic agents are able to lobby for opportunities to sell carbon offsets even though there is no associated reduction in the atmospheric concentration of CO_2. In particular, to demonstrate that the carbon offsets created are questionable in terms of their contribution to climate change mitigation, we use an example of a forest preservation activity in British Columbia (BC), which generated forest offset credits for the voluntary market but imposed real costs on the province's citizens.

Using a detailed forest management model, our study finds that forest carbon sequestration is highly sensitive to assumptions about the postharvest use of wood products, substitution of wood for concrete and steel in construction, and the ability to regenerate harvested sites with improved genetic stock. We demonstrate that the carbon offsets claimed to have been generated by a relatively small-scale forest protection project in the BC interior are overstated. In particular, we show that credits created by activities that enhance preservation of biodiversity enter the global carbon market without really contributing to net carbon reduction. Rather, by lowering the costs of emitting CO_2, such offsets signal that the future damages to society from climate change are lower than warranted so that more emissions can be tolerated. Overall, we illuminate how the institutional complexity of offset markets interacting with forest protection leads to rent seeking (Helm 2010), which undermines the notion that society can accept cost-effective, wide-scale, and more complex offset programs that are deemed economically efficient. In essence, we argue that there are many ways ex ante to create forest carbon offset credits, but, unfortunately, their soundness can only be established ex post.

The remainder of the paper is structured as follows. We begin in the next section by describing a forest preservation activity in BC that generated important voluntary offset credits. We then develop a Geographic Information Systems (GIS)-based forest management model of the study area, using publicly available data, which we subsequently use to compare carbon fluxes under different management regimes. The data are then described, followed by the results comparing carbon sequestration under various management regimes. We end with a summary and conclusions.

Carbon Offset Credits from Forest Protection: The Case of Darkwoods

Some 14.8% of BC's land base is officially protected, while 42% of forestland (22.6 million ha) has trees that are 140 years or older (BC Ministry of Forests, Mines, and Lands 2010). There are vast areas of forestland that are protected or inaccessible and, thus, unaffected by commercial timber operations. These forestlands have been impacted by wind throw (mainly on the coast) and by wildfire and the mountain pine beetle (mainly in the interior) but are left to regenerate naturally because of their inaccessibility. One might make the case that artificial regeneration that leads to higher and faster rates of growth—greater overall carbon uptake—should be eligible for VER credits, but then it would seem logical to also count the CO_2 emitted as a result of wildfire and/or decay of biomass as a debit. However, since natural processes have always contributed to atmospheric CO_2, it might make more sense neither to count CO_2 emissions from natural disturbance nor its removal from the atmosphere as a result of activities to mitigate the impact of the disturbance.

In 2008, The NCC purchased the 54,800 ha Darkwoods property on the west side of the south arm of Kootenay Lake near the US border (Figure 1) for $125 million from the German logging company Pluto Darkwoods, having received financial support for this purchase from the federal government.[2] Although nearly half of the Darkwoods site had previously been logged and regenerated, there remains a significant tract of natural forest with some trees as old as 500 years. Because the site also suffers from mountain pine beetle damage, logging of pine-beetle-killed timber has continued under NCC ownership, although annual harvests have fallen from over 50,000 m^3 under the private owner to 10,000 m^3 under NCC ownership.

In June 2011, NCC announced that it had completed a sale of 700,000 metric tons of CO_2 (tCO_2) offset credits to Pacific Carbon Trust, a BC government-owned corporation, and to Ecosystem Restoration Associates (ERA), a North-Vancouver-based company. The latter subsequently sold the credits in Europe through its German affiliate, the Forest Carbon Group—a German certifier of CERs under the CDM. NCC received more than $4 million for the sale, or nearly C$5.75 tCO_2^{-1}, at a time when offset credits were trading for more than C$15.00 tCO_2^{-1} on the European carbon exchange (ETS). An international environmental nongovernment organization (ENGO), the Rainforest Alliance (2011), certified the carbon offsets under the Voluntary Carbon Standard (VCS) label.[3]

Figure 1. Location of the Darkwoods site in southeastern BC.

The number of carbon offsets generated was determined as the difference in the carbon flux between the proposed NCC management regime (harvests of 10,000 $m^3\ yr^{-1}$) and the operation of the Darkwoods site by the hypothetical commercial operator.[4] The comparison between these management alternatives raises an issue regarding the counterfactual scenario. In making the case for certifying carbon offsets under the VCS label, the auditors note that: "Private land regulations in BC are quite strong compared to many other jurisdictions and the land is expected to be managed in compliance with all laws, under the direction of experienced land managers and Registered Forest Professionals" (Rainforest Alliance 2011, p. 34–35). However, when it comes to the counterfactual, the "proponent assumes that in the absence of the project, the most plausible baseline scenario is a market driven acquirer who implements a 15-year depletion of current mature timber stocks to provide a reasonable rate of return on investment, and a 100 year harvest schedule implemented with the typical regional practice of clearcut logging with minimum legal requirements for private forestlands in BC and comparable regional practices … [This is possible because] liquidation logging with little regard for basic environmental protections or sustainable timber production is legal and not uncommon in BC" (Rainforest Alliance 2011, p. 32). Not only does the latter statement contradict the earlier one, but private forest landowners would take offense at being told that their actions fail to take "basic environmental protections" into account.[5] Nor would it be possible for a timber liquidator to sell logs into a market that requires forest management standards to be certified by the Forest Stewardship Council (FSC) or another international certifier of forest practices. The counterfactual used to determine the carbon offsets generated on the Darkwoods site is not likely to be plausible.

In calculating the carbon offset benefits, the carbon sequestered annually in living biomass and long-term carbon stored in wood products constituted a credit, while CO_2 emissions associated with harvesting, hauling, processing, and silviculture constituted a source.[6] From the carbon stored in wood at the time of harvest, the analysts then subtracted the carbon released from decay during the period from the time of harvest to the end of the time horizon. Since physical carbon flows were not discounted, the release due to decay was substantial. As indicated in the next sections, these assumptions would have reduced the carbon benefits attributable to the commercial operator relative to a less exploitive management regime.

As to the purchasers in the Darkwoods case, Pacific Carbon Trust and the Forest Carbon Group engaged in rent seeking so as to acquire carbon offsets and resell them in a way that maximized their net returns. Such rent seeking by the buyers adversely impacts the efficient functioning of the carbon market at the forest level since the below market price received by the NCC for offsets results in too little forest preservation. Ideally, the buying and selling of carbon credits should take place in one market without the resellers, and it should not include project certifiers as eventual purchasers.

In a reassessment of the Darkwoods project and the claim that forest conservation can generate more carbon offsets than under private management, we examine a situation where the Darkwoods site is sustainably managed for commercial timber production while maintaining or increasing carbon stocks. If harvested fiber is stored in wood products, substituted for other material in construction or used to produce energy, this "will generate the largest sustained mitigation benefit" (IPCC 2007, p. 543). We demonstrate this in the following sections.

Forest Management Model of Darkwoods

In this section, we outline the forest management model as applied to the Darkwoods property, with a particular focus on carbon accounting. As the basis of our study we have adapted a forest model and accounting approach developed by Krcmar and her colleagues (Krcmar et al. 1998, 2001, 2003, van Kooten et al. 1999, Krcmar and van Kooten 2008). Besides modifications required for application to the current study site, major changes related to carbon accounting have been made—in particular, carbon data come from the Carbon Budget Model (as discussed in the data section) and an updated accounting approach is employed.

Let $x_{s,a,z,m,t}$ denote the ha of timber species s of age a in zone z that are harvested in period t and managed according to regime m, which refers in this case to the type of postharvest silviculture (natural or artificial regeneration). Also, let $v_{s,a,z,m,t}$ be the associated total merchantable volume ($m^3\ ha^{-1}$) of the stand at time t that is to be converted to lumber, wood chips (used in pulp mills or the manufacture of oriented-strandboard, medium-density fiberboard, etc.), or for production of energy and assume the stand's initial volume is given by $v_{s,a,z,m,0}$. Then we define total harvest in period t as follows

$$H_t = \sum_{s=1}^{S}\sum_{a=1}^{A}\sum_{z=1}^{Z}\sum_{m=1}^{M} v_{s,a,z,t}\, x_{s,a,z,t},\ \forall t, \tag{1}$$

where S is the total number of tree species, A the number of age classes, Z the number of zones, and M the management regimes. Zones constitute a combination of 12 biogeoclimatic subzones and two slope classes. Sites are further classified by seven primary and 10 secondary species.

We define the total costs (C_t) in period t as

$$C_t = C_t^{\log} + C_t^{\text{haul}} + C_t^{\text{silv}} + C_t^{\text{admin}} + C_t^{\text{process}}, \tag{2}$$

where

$$C_t^r = \sum_{s=1}^{S}\sum_{a=1}^{A}\sum_{z=1}^{Z}\sum_{m=1}^{M} c_{s,a,z,m,t}^r v_{s,a,z,m,t} x_{s,a,z,m,t},$$
$$\forall t,\ r \in \{\text{log, haul, silv, admin, process}\}. \tag{3}$$

In Equation 3, costs are much more coarsely defined than indicated. Thus, at time t, $c_{s,a,z,m,t}^{\log}$ are logging costs per cubic meter, but they only vary by slope; $c_{s,a,z,m,t}^{\text{silv}}$ are regeneration costs per ha and vary only according to whether regeneration is natural or by replanting, and $c_{s,a,z,r,t}^{\text{admin}}$ are administrative and development costs that are assumed to be constant on a per ha basis. Processing or manufacturing costs are embodied in the net value of logs, except as these relate to greenhouse gas emissions (see below). Finally, because the study region is small, trucking costs from a harvest site to the mill are nearly constant across the region and are given by $C_t^{\text{haul}} = c^{\text{truck}} \times H_t$.

Because the timber on the Darkwoods site is relatively homogenous, we assume that a proportion ε_1 of all the harvested timber is converted to lumber, a proportion ε_2 is sold as chips and a proportion ε_3 is used to produce heat or generate electricity, while the remaining proportion, $\varepsilon_4 = 1 - (\varepsilon_1+\varepsilon_2+\varepsilon_3)$, is left to decay at the logging site or as a result of processing. The price of chips is the same regardless of how chips are used. Let p_{lum}, p_{chip}, and p_{waste} be the fixed prices, respectively, of lumber, chips, and residual/waste wood fiber used for other purposes, including as fuel for heating or generation of electricity.

The constrained optimization problem can be formulated as a linear programming model with the following objective

$$\text{NPV} = \sum_{t=1}^{T} \beta^t \left[(p_{lum}\varepsilon_1 + p_{chip}\varepsilon_2 + p_{waste}\varepsilon_3)\, H_t - C_t - p_C(E_t + CO2_t^{eco} + CO2_t^{product} + S_t^{C\&S})\right], \tag{4}$$

where p_C refers to the (shadow) price of carbon dioxide ($\$\ tCO_2^{-1}$), and $\beta = 1/(1+r)$ is the discount factor with r the discount rate on monetary values. For simplicity and given fixed product prices and proportions ε_i, we assume that the price of logs ($\$m^{-3}$) ($= p_{lum}\varepsilon_1 + p_{chip}\varepsilon_2 + p_{waste}\varepsilon_3$) is the value of interest in the objective function (Equation 4). On the other hand, the price of CO_2 is used to incentivize the decisionmaker to manage the forest not only to harvest trees for commercial purposes but also to produce CO_2 sequestration services.

In the current implementation, the carbon price consists of a per unit tax on emissions, regardless of their source, and a subsidy for any removal of CO_2 from the atmosphere and subsequent storage in a variety of carbon pools. Notice that $CO2_t^{eco}$ and $CO2_t^{product}$ are the carbon stored in ecosystem and product sinks at time t. Because carbon is stored and released slowly over time, the associated carbon fluxes need to be aggregated to a single point in time, which is unnecessary for emissions that occur at a point in time. That is, it is necessary to account for the length of time that the carbon remains in a sink, preventing CO_2 from returning to the atmosphere—it is important to weight carbon flux as to when it occurs.[7] This issue is discussed further below. Finally, $S_t^{C\&S}$ refers to the CO_2 emissions from fossil fuels that are avoided in the production of cement and steel, say, if wood substitutes for nonwood products in construction.

Objective function 4 is maximized subject to Equations 1–3, a variety of technical constraints (see Krcmar et al. 1998, 2001, 2003), and the carbon dynamics. The technical constraints relate to the limits on harvest imposed by the available inventory in any period as determined by tree species, biogeoclimatic zones, slope, and age characteristics; a total area constraint (55,000 ha); growth from one period to the next (which is affected by management practices);

reforestation (management) options; limits on the minimal merchantable volume that must be on the stand before harvest can occur; sustainability constraints; nonnegativity constraints; and other constraints relating to the specific scenarios that are investigated. We also require that the harvest in any future period is within 5% of the first period harvest. This ensures a sustainable harvest rate and adequate investment in the future state of the forest to prevent degradation of the Darkwoods site, although the government might impose more stringent sustainability requirements.

Model parameters are provided in the data description section, while the constrained optimization model was constructed using the General Algebraic Modeling System (GAMS) (Rosenthal 2008). All mathematical programming models are solved in GAMS using the CPLEX solver on an IBM System X 3755-M3 terminal server.

Carbon Pools and CO_2 Emissions

Given that CO_2 fluxes (emissions, carbon capture, and carbon release from decaying biomass or wood products) vary over time according to the forest management regime, a method is needed to compare different carbon profiles. One approach is to use a discount rate on physical carbon to aggregate CO_2 fluxes over time. Discounting physical carbon assumes that CO_2 removed from, or released to, the atmosphere today is more important than removal of that CO_2 at some distant date. Discounting can be avoided, for example, by counting only the carbon fluxes that occur over some (arbitrary) time period.[8] The alternative of not discounting physical carbon leads to problems related to duration (van Kooten 2009). Unless current reductions in CO_2 emissions or removals from the atmosphere are considered more important than future ones, failure to weight carbon flows occurring at different times would encourage delay of mitigating action and, in the limit where there is no discounting of physical carbon, delay it indefinitely.

In the current model we take into account four categories of carbon flux: (1) CO_2 emissions from harvesting, hauling, and processing of logs into products and from silvicultural activities; (2) carbon that is sequestered in each period in the aboveground (leaves, branches, litter) and belowground (soil, roots) biomass; (3) carbon stored in wood products that decay over time; and (4) the avoided fossil fuel emissions when wood products substitute for nonwood products in construction. Since the price of fuel is fixed in the analysis as is the efficiency of equipment, CO_2 emissions, denoted E_t in Equation 4, are assumed to be fixed proportions of the logging, hauling, silvicultural, and manufacturing/processing costs. This is discussed further in the data description section.

To address ecosystem carbon flux ($CO2_t^{eco}$), we follow the approach employed by Malmsheimer et al. (2011). This is implemented in the current application using a forest growth-and-yield model that keeps track of carbon fluxes in the ecosystem. In particular, the carbon component of the model, which is described in greater detail in the data section, keeps track of living and dead biomass and whether it is above or below ground. The aboveground live component includes the wood, bark, branches, and leaves, while the belowground component constitutes the roots. The dead biomass stock includes litter and soil organic matter and roadside wastes, if any.

We consider the carbon stored in three product pools: in lumber, in products made from wood chips (including pulp), and in residuals and waste used to produce medium density fiberboard, wood pellets for exports, heat, or electricity.[9] The carbon stored in dead organic matter and material left at roadside are treated separately as

Table 1. Model parameters.

Parameter	Assigned value	Description
T	200 yr	Length of the planning horizon
T	10 yr	Time step
P_{logs}	\$75/m^3	Net price of logs (determined from all product prices)
p_C	{\$0, \$10} tCO_2^{-1}	Shadow price of carbon dioxide
c^{truck}	\$4.50 m^{-3}	Trucking cost per m^3 of logs fixed for each time period[a]
c^{log}	{\$22, \$42}	Logging cost per m^3 varies by slope category (<40°, >40°)
c_1^{admin}	\$8 ha^{-1}	Fixed administration & site development cost per harvested ha[b]
c_2^{admin}	\$14 ha^{-1}	Overhead and road maintenance cost[b]
c_z^{silv}	{\$1522, \$1605}	Fixed silvicultural cost per harvested ha by two major BEC zones
R	4%	Discount rate for monetary values; $\beta = 1/(1+r)$
r_c	{0%, 2%, 4%}	Discount rate for physical carbon; used to find duration factor g
ε_1	0.54	Proportion of merchantable volume converted to lumber
ε_2	0.25	Proportion of merchantable volume converted to chips
ε_3	0.21	Proportion of merchantable volume as residuals and waste
d_1	0.02	Decay rate for softwood lumber (proportion on annual basis)
d_2	0.03	Decay rate for chips and pulpwood (proportion on annual basis)
d_3	0.60	Decay rate of waste wood (proportion on annual basis)
d_4	0.00841	Decay rate of dead organic matter (proportion on annual basis)
ξ	{0.0, 0.25, 0.75} tC m^{-3}	Emissions avoided when wood substitutes for other products[c]
	150 m^3 ha^{-1}	Minimum volume before site can be harvested

[a] Assumes a cycle time of 1 to 2 h.
[b] Two types of fixed administrative costs are identified—one associated with site maintenance, the other with road maintenance. With regard to the second, Thomae (2005) uses an overhead cost of \$11.24 ha^{-1} and road maintenance cost of \$2.56 ha^{-1}.
[c] Avoided emissions vary from 0.5–0.9 tC per m^3 (1.8–3.3 tCO_2 m^{-3}) for steel and 0.1–0.3 tC m^{-3} (0.37–1.1 tCO_2 m^{-3}) for concrete (Hennigar et al. 2008). We employ 0.0, 0.25, and 0.75 tC m^{-3} as a sensitivity checks.
Source: Adapted from 3GreenTree Ecosystem Services & Ecosystem Restoration Associates (2011, p. 133, 137), Thomae (2005), Niquidet et al. (2012), Hennigar et al. (2008), and Ingerson (2011).

is the carbon in living matter (which does not decay). Let the rate of decay for each of the three product pools be denoted d_1, d_2, and d_3, respectively, and that decay begins in period $t+1$ following harvest in period t. Then, assuming physical carbon is discounted at rate r_c, the carbon stored at time t in the three product pools as a result of harvest H_t is given as[10]

$$CO2_t^{product} = \varphi \sum_{i=1}^{D} \frac{r_c}{r_c + d_i} \varepsilon_i H_t, \quad (D = \text{lumber, chips, residuals/waste}). \quad (5)$$

where d_i is the decay rate of carbon in product pool i (see Table 1 below), and parameter φ (= 44/12) converts carbon to CO_2. Notice that, when the discount rate on carbon is zero ($r_c = 0\%$), no carbon is effectively retained in carbon products as all carbon is eventually released to the atmosphere.

The corollary to Equation 5 relates to emissions of CO_2 from decaying wood products. Because the rate at which carbon in post-harvest product pools returns to the atmosphere varies considerably in our model (see Table 1), the release of CO_2 from postharvest products is charged to a common date, namely the time of harvest; this again requires the use of a discount rate on physical carbon. Consider perhaps the most important carbon pool, namely, wood products. As demonstrated with respect to Equation 5, if 0.27273 tC (=1.0 tCO_2) is stored in wood products, the amount of CO_2 released as a result of future decay of wood products at the time of harvest is equivalent to

$$\theta = \sum_{i=1}^{D} \left(\frac{d_i}{d_i + r_c} \right) \varepsilon_i, \tag{6}$$

where θ is measured in tCO_2 per cubic meter of harvested wood and ε_i is the proportion of harvesting going into product pool i. Clearly, if the CO_2 flux is not weighted according to *when* it occurs, CO_2 released today is treated the same as CO_2 released 50 years from now or 200 or even 1,000 years from now. Thus, if $r_c = 0\%$, all CO_2 stored in timber is treated as if it is released immediately on harvest.

The implication of Equations 5 and 6 is clear. As the rate used to discount physical carbon increases, future CO_2 emissions from the decay of wood products or biomass matter less. Thus, it appears that more carbon gets stored in wood products, say, as the discount rate on physical carbon rises. From a carbon perspective, this favors harvest activities that result in increased processing of biomass into products. On the other hand, low discount rates on carbon favor lower harvest intensity. This insight is crucial to the results, but it is also important because, by using a zero discount rate for carbon, the implication is that climate change is not an urgent matter. After all, $r_c = 0\%$, implies that the removal of CO_2 from the atmosphere can be delayed indefinitely.

Lastly, we consider the avoided fossil fuel emissions when wood products substitute for nonwood products (viz., aluminum studs, concrete) in construction (Hennigar et al. 2008)

$$S_t^{C\&S} = \varphi \xi H_t, \tag{7}$$

where ξ is a parameter denoting the emissions avoided when wood substitutes for other products. If $\xi = 0$, there is no benefit when wood substitutes for nonwood products in construction. In the scenarios, we consider various values of ξ, including zero.

Data Description

A GIS model of the Darkwoods site was initially constructed. Since we were unable to obtain the inventory data used by the assessors, we employed information on biogeoclimatic zones, existing data on inventory and timber supply in the adjacent Kootenay Lake Timber Supply Area (TSA) (Figure 1), and publicly available forest cover data to develop a timber inventory for the Darkwoods site. This made it possible to identify the age and type of tree species growing on the site by biogeoclimatic zones, slope categories, and other spatial characteristics—the timber inventory on the site.

To predict timber growth and yield of managed and natural stands, we then employed the TIPSY model, which is used by the BC Ministry of Forests, Lands and Natural Resource Operations, for example, for timber supply analysis. TIPSY refers to the Table Interpolation Program for Stand Yields; it includes the Tree and Stand Simulator (TASS) and a variable density yield prediction system for natural stands.[11] TASS employs the Carbon Budget Model of the Canadian Forest Sector (Kurz et al. 1996, Kull et al. 2011) to track all living and dead biomass and whether it is above or below ground. TIPSY can be used to evaluate silvicultural treatments and address other stand-level planning options; it also provides the addition to dead biomass in each period and the cumulative live biomass as the stand grows so that decay of dead matter is not explicitly taken into account. Using TIPSY carbon fluxes and the decay rates in Table 1, it is straightforward to calculate the "periodic recruitment" of carbon, which can then be translated into a CO_2 equivalent measured in metric tons.

The Darkwoods property consists of 10,332 stands of potential timber, with an average merchantable timber volume of 247.3 m^3 and 97.2 tC (= 365.5 tCO_2) in living biomass. In the current application, TIPSY is used to determine the evolution of the forest for each of the various sites in the GIS model, whether the site was harvested or not. TIPSY output is then called directly into the forest management model written in GAMS.[12]

Data on prices, costs, and discount rates used in the model are also reported in Table 1. For convenience and because it has little effect on the results, we employ a constant rate of 4% for discounting monetary values but employ rates of 0, 2, and 4% for discounting physical units of carbon.

Consider the effects of silviculture. As noted earlier, a commercial operator needs to ensure that its management practices are sustainable and is therefore required to regenerate a site once it is harvested. In that case, the site is replanted with genetic stock from tree nurseries, and, because some selective breeding for growth characteristics, such as height or pest resistance, has occurred in the nurseries, these seedlings grow faster than the harvested or naturally regenerated trees (BC Ministry of Forests, Mines, and Lands 2010, p. 147–148). Artificial regeneration could lead to a substantial increase in the amount of carbon sequestered; not only does it lead to earlier establishment of a growing forest than if the stand were left to regenerate on its own, but, because higher-quality trees are planted, the total amount of biomass grown on the site could be significantly enhanced. Indeed, by planting nursery stock, the site index (expected height of trees at a particular age) for the same tree species can be increased from, say, 20 m on a 50-year basis to perhaps 28 m, or by 40%. This might translate into an increase in the amount of carbon stored on a site by perhaps 30% compared to allowing natural regeneration. This is a clear benefit of permitting harvest activities and is included in the TIPSY output. Silvicultural costs are provided in Table 1 for artificially regenerated stands.

We also consider the potential impact of avoided emissions when wood is substituted for nonwood products, such as steel and concrete in construction. Information on the extent of avoided emissions is reported in Table 1, with values of ξ ranging from 0.0 to 0.75, although Hennigar et al. (2008) report values as high as ξ = 1.5. Notice, however, that we do not account for the fossil fuel savings from burning wood because electricity in BC is generated almost exclusively from hydro sources. Finally, we include CO_2 emissions associated with the activities of harvesting, trucking and manufacturing of wood products (see Table 2).

Results: Comparison of Carbon Sequestration across Scenarios

Our forest management model of the Darkwoods site employs a 200-year time horizon with a 10-year time step. The long time horizon is required to eliminate problems related to the determination of the site's salvage value, while a 10-year step is required to facilitate achieving a numerical solution to the model. Because the (commercial) decisionmaker in our model begins to increase harvests in anticipation of the end of the time horizon as early as 2 decades beforehand, we present results only for 150 years while still optimizing over 200 years. The long time horizon implies that the discounting of physical carbon plays a crucial role in what one can say about the importance of forest carbon offsets.

We first establish a baseline level of carbon sequestration by assuming that the Darkwoods site is designated a wilderness area with no harvesting or other management.[13] To determine the carbon flux for a natural forest, we maximize the growing stock subject to the biophysical inventory and growth constraints and a constraint limiting harvest to zero. Next, we examine the levels of carbon uptake under NCC management by maximizing net revenues from timber harvest subject to the growth, inventory, and other constraints imposed by the NCC.[14] Lastly, we find the carbon flux under commercial management by maximizing Equation 4 subject to constraints 1–3 and other technical constraints required in the model (as discussed above) plus constraints required by the government or a certifier of sustainable forest management practices (as opposed to a certifier of carbon offsets). The baseline includes carbon stored in products but not the avoided fossil-fuel CO_2 emissions from substituting wood for nonwood materials in construction. The baseline carbon fluxes are provided in Figure 2.

When physical carbon is not discounted, leaving the Darkwoods site as wilderness leads to the greatest carbon benefit. In this case, there are no product pools to consider because there is no harvest. Thus, assuming no wildfire or further pest and/or disease outbreaks, carbon sequestration continues as long as forest growth exceeds decay. In the current situation, the forest is growing faster than it decays because the starting inventory includes significant young stands as a result of previous logging activities. In our model, the decline in net carbon uptake begins after about 70 years when tree growth slows down. Much the same is true for NCC management, except that CO_2 emissions from harvesting and processing activities are counted against those from growing trees.

With $r_c = 0\%$, emissions from commercial harvesting and processing wood initially offset the gains from planting new trees, although the latter gains dominate after about 50 years with CO_2 flux leveling off after about 90 years. Since no effective carbon is stored in product pools (see Equations 5 and 6), the only gains in carbon come from regeneration of stands. Whether the property is managed by the NCC or a commercial operator, the CO_2 removed from the atmosphere from growing trees minus that emitted from harvesting and processing activities is not sufficient to overtake the CO_2 sequestered by simply leaving the forest as wilderness (at least over the 150-year time horizon). Further, the net carbon flux on the property with a commercial operator will after 80 years exceed that under the NCC management, simply because the commercial operator will have more fast-growing immature forests on the site at that time.

When carbon fluxes are discounted, the story changes significantly: CO_2 released from future decay of wood products is weighted less than CO_2 released closer to the time of harvest. The higher the discount rate on physical carbon, the less important are future fluxes in carbon. This follows from Equation 6 and is also shown in Figure 2. The commercial operator would end up storing much more carbon in postharvest product pools, which, along with regeneration of harvested sites with younger and faster growing trees, leads to much greater potential for carbon offsets than under a NCC management regime. Although carbon flux also increases under the NCC management plan, the harvests are too small to result in significant carbon storage in wood products.

The story changes even more when a commercial manager is incentivized to reduce CO_2 emissions and increase sequestration of carbon in growing trees and wood products. It is further impacted when fossil fuel savings from reduced use of cement/concrete and steel/aluminum in construction because wood materials are used as substitutes (Hennigar et al. 2008). Summary results for these situations are provided in Table 3 and illustrated in Figure 3.

Net carbon sequestration results are provided in Table 3 for carbon discount rates of 0% and 4% and carbon prices of \$0 tCO_2^{-1} and \$10 tCO_2^{-1}. As noted earlier, these represent extremes in terms of the carbon offsets that might be generated over the 150-year time horizon; the results for a 2% discount rate for carbon

Table 2. Carbon emissions (e_i) by activity.

Activity	Emissions (tC per tC raw material)
Harvesting	0.016
Manufacturing	
Sawnwood	0.040
Veneer, plywood, panels	0.060
Nonstructural panels	0.120
Mechanical pulping	0.480
Chemical pulping	0.130
Trucking (50 km)	0.00007 per km

We assume only mechanical pulping.
Source: GreenTree Ecosystem Services & Ecosystem Restoration Associates (2011, p. 137).

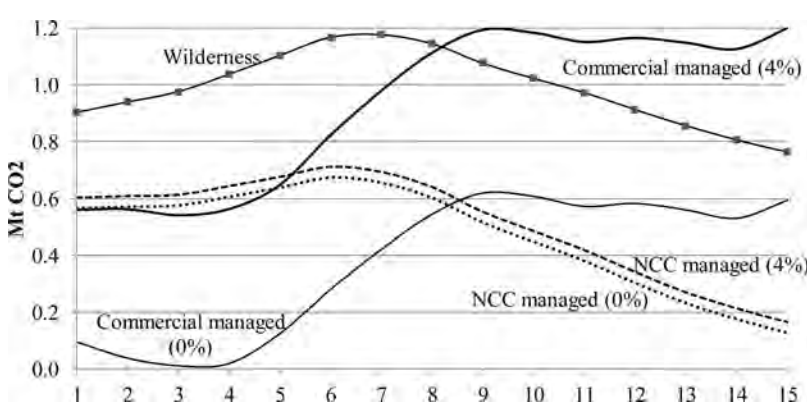

Figure 2. Carbon flux on Darkwoods site, wilderness, NCC management and commercial management; biological and product carbon pools only; carbon discount rates of 0 and 4%.

Table 3. Annualized carbon sequestered for management alternatives, carbon prices, with and without carbon discounting and wood product substitution rates,[a] monetary values discounted at 4% (Mt CO_2).

Management type	Price of carbon = \$0 tCO_2^{-1}		Price of carbon = \$10 tCO_2^{-1}	
	0%[b]	4%	0%[b]	4%
Wilderness	0.099	0.064	0.099	0.064
No fossil fuel savings from substituting wood for concrete/steel ($\xi = 0.0$)				
NCC managed	0.047	0.196	0.048	0.205
Commercially managed	0.037	0.351	0.040	0.356
Low fossil fuel savings from substituting wood for concrete/steel ($\xi = 0.25$)				
NCC managed	0.075	0.332	0.077	0.341
Commercially managed	0.102	0.805	0.107	0.816
Medium fossil fuel savings from substituting wood for concrete/steel ($\xi = 0.75$)				
NCC managed	0.093	0.403	0.095	0.412
Commercially managed	0.281	1.496	0.285	1.515

[a] ξ is the rate wood substitutes for steel/concrete in construction and is measured in tC m^{-3} of harvested commercial timber.
[b] This is not a pure annualized value but obtained by taking total carbon accumulated over 150 yr divided by 150; for the 4% discount rate, a true annualized value is reported.

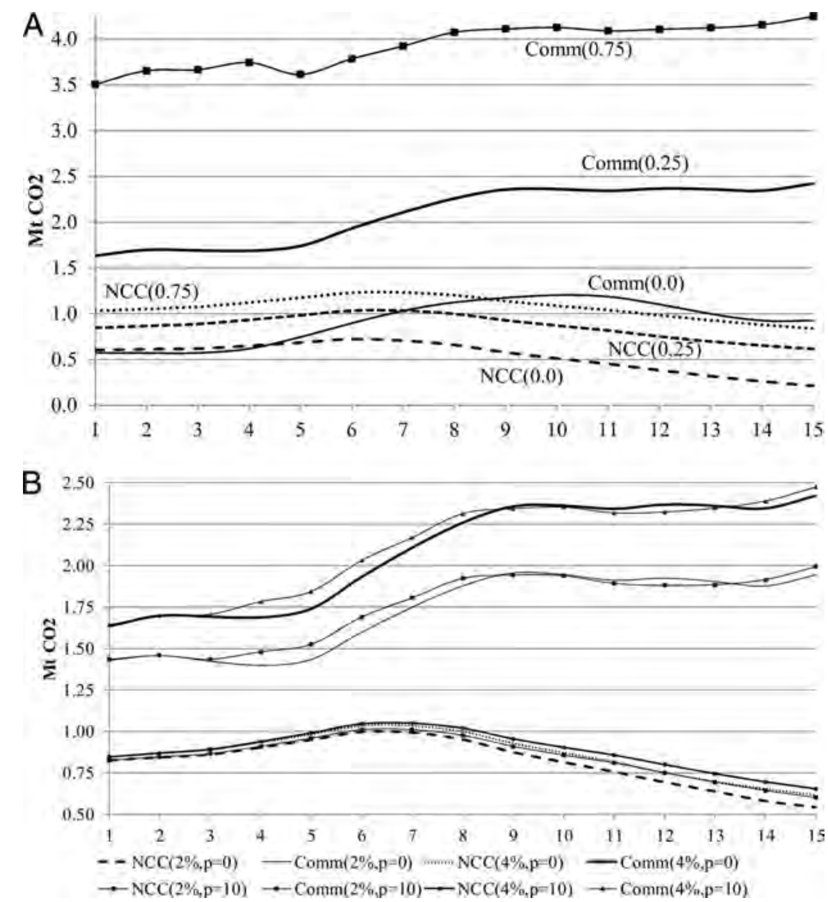

Figure 3. Net CO_2 sequestered per decade: NCC versus commercial management, 4% discount rate for monetary values. (A) Carbon price of \$10 per tCO_2, 4% discount rate for physical carbon fluxes, and various wood substitution parameters (in parentheses; tC m^{-3}). (B) Carbon flux, 2% and 4% carbon discount rates, \$0 and \$10 per tCO_2 carbon prices.

fall between those of 0% and 4%, while results for a \$50 tCO_2^{-1} price lead to the same levels of carbon as the \$10 tCO_2^{-1} price. With a 4% discount rate on monetary values and no carbon price to incentivize forest managers to sequester carbon and reduce CO_2 emissions, the amount of undiscounted CO_2 sequestered by the NCC management plan averages some 52,000 tCO_2 per annum below that which would be stored in biomass had the region been left solely to wilderness. While timber growth is somewhat faster than in the case of wilderness, NCC management results in CO_2 emissions from the little harvesting, hauling, processing, and silvicultural activity that occurs on the site, with any carbon stored in products effectively lost to the atmosphere on harvest (as noted in conjunction with Figure 2). When physical carbon is discounted at 4%, however, the NCC plan leads to greater storage than wilderness, by some 97,000 tCO_2 annually.

The potential to create forest carbon offsets increases only slightly if the NCC manages Darkwoods to take into account the sales value of carbon offsets. This assumes that, while harvest levels do not change, land is managed somewhat differently (e.g., different sites are chosen for harvest, treeplanting occurs faster). In the absence of discounting, annual positive carbon flux is 51,000 tCO_2 below that associated with wilderness; at a carbon discount rate of 4% (so carbon stored in products is now taken into account), the NCC plan results in 106,000 tCO_2 more per year than wilderness. Of course, the NCC carbon flux is nearly equivalent to that of wilderness if carbon stored in products is not taken into account (0% carbon discount rate), while the NCC plan clearly leads to much greater overall carbon offsets (as much as 313,000 tCO_2 annually) if fossil fuel savings from substituting wood for nonwood construction materials are taken into account. It is only when carbon is discounted that NCC management results in positive carbon offsets relative to leaving the site as wilderness (Table 3). The reason is that carbon stored in wood products is counted when the carbon discount rate is not zero.

Leaving land in its natural state or adopting the NCC plan is preferred to commercial operation of the Darkwoods property only if the only carbon fluxes to be considered are those related to timber growth (including carbon in all above- and belowground pools) and CO_2 emissions from harvesting, hauling, and processing wood—that is, postharvest carbon pools are ignored. The potential of the commercial operator to create carbon offsets increases with the price of carbon, the discount rate on physical carbon (so future release of CO_2 from product pools is counted less today), and the savings from avoided fossil fuel emissions when wood substitutes for steel and concrete. The latter point is illustrated most clearly in Figure 3a, where only the potential fossil fuel savings from substituting wood for nonwood products in construction are considered.

Although not shown diagrammatically, carbon prices have little impact on carbon flux. One expects a higher carbon tax/subsidy to lead to more sequestration because the commercial operator benefits not only from carbon stored in products but also from credits related to the avoided fossil fuel emissions when wood substitutes for nonwood products in construction. At higher carbon prices, a commercial operator wants to harvest as many trees as possible to benefit from carbon offsets created by storing carbon in products and claiming these avoided fossil fuel emissions. Likewise, the commercial forestland owner will regenerate the forest quickly to take advantage of carbon uptake credits, because the seedlings that are planted grow faster than ones that regenerate naturally, while both grow much faster than mature trees. However, our results also indicate that the harvest strategy does not change for carbon prices ranging from $10 to $50 per tCO_2 (higher prices were not considered). A commercial operator does not harvest more trees because of the sustainability requirements and biophysical constraints on growth. Yet the commercial operator does have somewhat more flexibility to pursue opportunities to generate carbon offset credits than under the stricter management regime imposed by the NCC.

If the avoided emissions from substituting wood for nonwood in construction are credited, sustainable commercial management of the Darkwoods site always leads to improved carbon sequestration compared to wilderness or NCC management (Figure 3). If avoided emissions are not considered, a commercial operator will still create more carbon offsets as long as carbon in the product pool is counted. In our model this implies that future carbon flux is discounted relative to current carbon uptake or CO_2 emissions. It is most striking that commercial management of the forest could lead to much higher levels of carbon uptake than would occur under NCC management.

We have not addressed leakage. If prices of wood products are unaffected by products from Darkwoods (a reasonable proposition given the property's small contribution to regional timber supply), then lumber from Darkwoods, for example, would simply substitute from lumber produced elsewhere. In that case, the carbon stored in forest products from Darkwoods and the associated CO_2 emissions from logging, hauling, processing, and silvicultural activities would be offset by reduced production elsewhere. The same would be true for the substitution of wood for nonwood products, as this only occurs if the prices of wood products fall relative to those of nonwood—the harvests from Darkwoods are likely insufficient to impact markets to such an extent. This makes it even more difficult to determine the extent to which carbon offset credits can be claimed. Clearly, the number of carbon offsets that a forestry project might be able to claim is highly sensitive to a variety of assumptions about what might happen in the real world.

Discussion

International agreements have legitimized the use of forest sector carbon offset credits for meeting emissions reduction targets. They are considered a stop-gap measure to enable countries and/or companies to meet targets, while they invest in technology and processes that reduce actual CO_2 emissions. However, there are problems with the use of forest offset credits.

First, most analyses of the potential carbon offsets from forest conservation projects do not use optimization methods, primarily because they are difficult and expensive to carry out. That is, evaluation of forest carbon offset projects greatly increases transaction costs.

Second, to our knowledge, the original evaluation of Darkwoods' carbon offsets failed to discount physical carbon and did not consider regeneration of harvested sites with improved genetic stock or the avoided fossil fuel emissions when lumber substitutes for steel or concrete in construction. If carbon is not discounted, CO_2 removed from the atmosphere 50 or 100 years from now is treated the same as CO_2 removed today. Thus, the carbon offsets created by a project where CO_2 uptake occurs later than sooner are overstated compared to a project that sequesters carbon early on. Further, if postharvest carbon product sinks are taken into account, landowners seeking to create carbon offsets will harvest trees as soon as possible to be able to credit carbon entering product sinks. This also enables landowners to plant a new crop of trees that sequester carbon faster than those that were harvested, thereby generating more carbon offset credits. Indeed, if stands are regenerated using seedlings from tree nurseries (enhanced genetic stock), carbon is sequestered even faster, yielding more carbon offsets than if stands were allowed to regenerate on their own. Further, more carbon offset credits could be earned if emission reductions resulting when wood products substitute for concrete and/or steel in construction are counted.

Nonetheless, this is not the main shortcoming. Rather, it is simply that, ex ante, it is possible to come up with various claims regarding the forest carbon offsets that a land management project generates—there is no clear way of determining how many carbon offsets are created and whether some other management regime would create more or less. It is difficult enough to determine the offset credits created by a treeplanting project when account is taken of future harvests, but, when it comes to forest conservation or preservation, it is likely an impossible task. Unmanaged forests are not capable of sequestering as much carbon as forests that are managed sustainably, where harvested timber is used to produce energy and/or wood products that store carbon and substitute for other construction materials and where harvested sites are artificially regenerated (IPCC 2007, Malmsheimer et al. 2011, Oliver 2013).

Third, the conclusions of most studies of forest carbon sequestration are only made worse if one takes into account problems related to additionality, carbon leakage, impermanence (duration), and transaction costs (measuring, monitoring, etc.), which lead to even larger variation in estimates of carbon sequestration and, thus, the carbon offsets that might be claimed. The complexity of all the carbon fluxes and the task of identifying them leads to an asymmetry (Mason and Plantinga 2013), which, in turn, opens the door to rent seeking opportunities. This is a systemic problem in the market for voluntary carbon offset credits that needs to be avoided in true markets.

These points were demonstrated using a case study of a forestry estate in southeastern BC, Canada. The environmental organization that owns the site managed to sell 700,000 tCO_2 offset credits for which it received \$4 million, or about \$5.75 tCO_2^{-1}. The buyers subsequently turned around and sold the credits for as much as \$25 tCO_2^{-1}. The problem was that the buyers were not only promoters of the sale but also helped facilitate the sale (BC government) or certified the number of carbon offsets the project created (Ecosystem Restoration Associates and its German subsidiary). Our analysis indicates that, given the assumptions used to create the offset credits, the forest estate is capable of creating additional carbon offsets. Indeed, we find that, compared to commercial operation of the site, managing the forest estate under the conditions proposed by the NCC might imply forgoing nearly twice as much CO_2 sequestration as was claimed, or more than 1.1 Mount CO_2 (Table 3).[15] However, the amounts of forest carbon offsets that could be justified ex ante depend on the method of analysis, the assumed baseline, land tenure, other assumptions relating to the length of time horizon, discount rates, and postharvest carbon storage and regeneration. As a result, a wide variety of forest offset values could be justified, which makes it difficult to accept any, particularly if one is serious about addressing climate change. This might have been a reason why Europe originally opposed the use of forest carbon offsets in lieu of actual CO_2 emissions reduction.

Finally, it is worth noting that the costs of monitoring and verifying the creation of carbon offsets can be extremely high, which might explain why many projects are accepted and granted the right to sell carbon offsets. In the Darkwoods case study considered here, it was necessary to construct a GIS model of the site, determine the current inventory, estimate growth and yield under various management alternatives, and develop a forest management model that included a component that kept track of carbon pools over time. It is clearly the case that, unless an independent certifier with no stake in the outcome is able to spend the time necessary to judge a project, many questionable offset credits will be forthcoming on (global) carbon markets (Helm 2010). This distorts the functioning of carbon markets by reducing the value of carbon.

Endnotes

1. While some VERs may indeed be sold in a compliance market, it is more likely that they are sold to various private and public entities that might otherwise make purchases in the ETS.
2. Information is available from stories appearing June 10 and 11, 2011 in local newspapers, the *Vancouver Sun* and national *Globe and Mail*.
3. On-the-ground certifiers appear to be local rather than international because the assessment was conducted by the local office in Nelson, BC, although the Rainforest Alliance has its head office in Virginia.
4. The documentation of the methods used to calculate carbon offsets is somewhat opaque. Therefore, we may not correctly characterize the procedure used to determine the carbon flux associated with the NCC scenario, both here and in the results section below.
5. In this regard, see www.pfla.bc.ca/.
6. See 3GreenTree Ecosystem Services & Ecosystem Restoration Associates (2011, p. 19–20). The aboveground, nontree living biomass, litter, and soil carbon pools were not included.
7. The importance of discounting physical flows of resources as to when they take place is well established (see van Kooten 2009, van Kooten 2013, p. 332–334).
8. To avoid weighting carbon fluxes according to when they occur, the United Nations' Framework Convention on Climate Change (UN FCC) process has developed a variety of methods to compare carbon fluxes from alternative forest activities (e.g., van Kooten 2013, p. 355–358), but none is as efficient as the use of a carbon discount rate.
9. Residuals and waste are often burned on site (at a mill) to reduce energy costs. We do not count avoided emissions from fossils when wood is burned to generate electricity, partly because we lack information on the exact disposition of residuals and waste wood but also because forest companies would otherwise purchase emissions-free hydropower for heating.
10. This follows because $\lim_{n\to\infty}\left\{C + \frac{(1-d)C}{1+r_c} + \frac{(1-d)^2C}{(1+r_c)^2} + \ldots + \frac{(1-d)^nC}{(1+r_c)^n}\right\} = \frac{r_c}{r_c+d}C$, where d is the rate of decay of carbon C.
11. Information can be found at www.for.gov.bc.ca/hre/gymodels/tipsy/assets/intro.htm.
12. The data files from TIPSY and the GAMS files are available from the authors upon request.
13. Except perhaps fire suppression, as we do not take into account possible wildfires (see, e.g., Couture and Reynaud 2011). Including wildfire risk, however, would reinforce the overall conclusions reached below.
14. As in the case of the natural forest where we maximize growing stock, maximizing net revenue is simply a device used in the model to implement the NCC's management strategy (annual harvest of 10,000 m^3) and is not meant to imply that the NCC acts to maximize profit from timber harvesting.
15. The implication is that an additional 12 Mt CO_2 is released into the atmosphere in exchange for protection of a 55,000 ha forest estate and the environmental benefits it might provide.

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