Issues and Options for the Design of an Offset Program within a Carbon Allocation System in Oregon

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DISCUSSION DRAFT

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EXECUTIVE SUMMARY

Offsets are avoided or sequestered emissions that occur off-site, outside of the boundaries of the load-based cap. Favored by industry participants, offsets offer an alternative means of compliance, enhancing flexibility and helping to lower compliance costs. However, for offsets to be traded on par with allowances, they need to be of high quality.

The following questions should be considered by the Oregon Carbon Allocation Task Force as they decide whether to allow use of offsets and the types of offsets that are deemed acceptable.

Should Offsets Be Allowed?
Because a cap-and-trade program establishes an actual cap on emissions, assessing emissions reductions is straightforward. Essentially, all emissions reductions below the cap qualify as additional, and any emissions in excess of the cap must be compensated.

However, in the case of offsets, there is no cap. Rather, the relevant metric is "better than business-as-usual" where "business-as-usual" may not be entirely straightforward and depends on a range of uncertain future projections. Moreover, offsets must demonstrate that they were accomplished with the express purpose of reducing emissions and would not have happened "anyway", which is difficult to prove, and that the emissions reductions that are measured are permanent.

While there are rules and tests and procedures to help answer the question of whether a given offset is legitimate, it is not a hard science. And the greater effort used to verify an offset, the greater the transaction costs, and the less overall value offered by the offset program in terms of cost savings. It is an open question as to whether the anticipated compliance flexibility and cost savings from allowing offsets outweigh the difficulties in ensuring that a given reduction is real, additional and permanent. The answer may depend in part on the overall stringency of the cap and expected allowance price.

In the event that the state decides to allow offsets, the next set of questions helps define the quality and quantity of those offsets. Essentially, each question frames a key design decision that the Task Force will need to make. These issues are discussed in more detail in the report that follows.

Which additionality test(s) should be used?
The state needs to decide whether it is more legitimate to allow all offsets that are additional to an emissions baseline that provides a "best guess" of business-as-usual future emissions absent the proposed project, or just offsets that meet a series of barriers tests that attempt to answer why a project was undertaken.

How should permanence be addressed?
Projects that may not be permanent can be discounted or disallowed altogether. Alternatively, issuance of credits could be delayed or "true up" periods could be shortened. Finally, non-permanent credits could be guaranteed by the seller, who

essentially must have an option to purchase “back up” (permanent) credits in the event that the original credits purchased are lost.

Where can credits be earned?
Limiting offsets to Oregon would provide the most co-benefits (emissions, jobs, etc.) but at the highest cost. There is also a risk of creating an entitlement in which sectors expect to be able to sell excess reductions rather than be subject to a mandate. Allowing offsets across the US would lower the costs as well as quality control. There would also be few, if any, co-benefits for Oregon. Allowing international offsets would provide the lowest cost offset compliance opportunities at Clean Development Mechanism (CDM) quality but with no co-benefits for Oregon.

Should credits expire?
Requiring credits to be used over a particular timeframe might be considered to reflect the likelihood that the project baseline will change over time as new technologies become standard or new requirements come into place. However, early expirations will reduce the value of credits in terms of compliance flexibility and cost savings. An alternative is to periodically update project baselines, but this could be burdensome.

Which sectors should be allowed to earn offsets?
Given the not insignificant effort involved in developing protocols for offset creation for different industry sectors and the need to build confidence that the offset program will create reductions that are quality equivalents to allowances, it may be desirable to prioritize among industry sectors or to begin with a pilot program.

- The forestry and agriculture sectors offer a number of challenges with respect to baseline accounting, leakage, project timing and project permanence. However, these sectors also offer significant potential for earning offsets. Should the state allow offsets from these sectors? And if so, are there specific offset activities from these sectors that are of greatest interest?

- The power sector should not be allowed to earn offsets to avoid double counting, but should there be a set-aside program within the cap (or an auction from which revenues are recycled to these sources) from which energy efficiency projects can earn allowances (or financial compensation)?

- Non-power emitting sectors offer significant opportunity for offset creation. Some sectors such as landfills and biodigesters offer straightforward accounting of emissions reductions and may be prime targets for building experience in offset development. Other sectors (e.g., direct emissions from commercial and residential sources) require upfront work to streamline offset procedures to facilitate participation.

Should limits be placed on offset creation or use?
To ensure that some emissions reductions take place in the power sector where long-term investments are being made, and to hedge the possibility that offsets may not equate to

the value of allowances, the state may opt to place limits on the creation or use of offsets. Limits could be based on the share of compliance that may be met with offsets, allowance prices above which more flexibility is deemed to be needed, or based on the development of restrictive standards for offset development.

Should sectors that are strong candidates for future regulation be allowed to earn offsets?

Large GHG emitters such as cement and manufacturing sectors are not the subject of the carbon allocation task force scope of work at this time. However, once decisions are made on regulation of the power sector, the state expects to consider options for controlling emissions from other sectors of the economy. The concern is that in allowing such sectors to create offsets, they will have a strong financial disincentive to later engage in the design of a mandatory control program. If this is a concern, design options include development of sector baselines, requiring an independent contribution towards the state target, and use of a sunset date.

INTRODUCTION

This paper is being developed to assist the Oregon Carbon Allocation Task Force to consider the inclusion of an offset system as part of its evaluation of a load-based carbon allowance standard. An offset system provides affected companies with compliance flexibility that can help build support for the broader cap-and-trade program.

What are Offsets?

Offsets are emissions reductions as well as avoided or sequestered emissions that occur outside the boundaries of a cap-and-trade program. Regulated emitters may use offsets for compliance with a cap in lieu of making emissions reductions within the capped system. To the extent that offsets are allowed and used as a means of compliance, emissions within the capped system may exceed the established cap. On net, however, emissions with credible offsets would be the same as without offsets.

Advantages

The potential advantages of allowing offsets include 1) added compliance flexibility, 2) lower costs of compliance, and 3) the possibility of gaining experience in reducing emissions in sectors that are not subject to the cap. In addition, depending on the program design, offsets can lead to additional co-benefits in Oregon.

A first advantage of an offset program is added compliance flexibility. However, it is important to note that a load-based allowance trading system for the power sector *intrinsically* offers a relatively high degree of compliance flexibility in that load-serving entities may opt to 1) shift power supply contracts from higher-emitting power sources to lower-emitting power sources, 2) replace generation from higher-emitting sources they own and operate with lower-emitting sources, and/or 3) encourage more energy efficiency from within their electric service territory.[1] Accordingly, under a load-based cap, capped sources are not limited to GHG mitigation opportunities at their own plants and service territories or even within the power sector as a whole.

The choice to allow offsets would further expand the universe of allowable mitigation activities to measures that displace direct combustion of fuels outside of the power sector as well as to process emission reduction and sequestration activities. In this way, allowing offsets would potentially encourage actions that have lower marginal costs than the on-system reduction opportunities, and lower the overall power system costs of complying with a load-based carbon allowance standard.

A second advantage of an offset program, related to the first, is the potential to lower compliance costs. A number of modeling studies of generation-based cap-and-trade programs, for example, an October 2005 modeling study conducted by the US EPA of the Clean Air Planning Act (S.843), have considered the potential benefits of offsets in reducing compliance costs. Note, however, that the cost advantage of having an offset

[1] Under a generation-based cap-and-trade system, generators typically have less compliance flexibility given their capital investments in particular generating technologies. Also, generators may not have experience in energy efficient and renewable energy technologies.

program may be lower under a load-based allowance trading system than under a generation-based trading system because energy efficiency, an in-system compliance opportunity, may offer lower-cost mitigation than off-system opportunities. On the other hand, industry may still value having the option of going off-system as insurance in the event that on-system activities do not yield the desired level of reductions.

A third important advantage of allowing offsets is the possibility of gaining experience in reducing GHG emissions in sectors outside of the power industry. Allowing offsets provides a financial incentive for innovation and GHG mitigation in sectors of the economy that may be able to produce eligible offsets at a lower cost per ton than what is possible within the power sector. Knowing which sectors have low-cost mitigation opportunities may be helpful in targeting future requirements at the state and/or national levels.

While some may cite emissions and economic co-benefits from off-system GHG emissions reductions as an additional advantage, these co-benefits need to be assessed against those that would otherwise be achieved from on-system actions. Power sector mitigation measures such as new investments in energy efficiency and renewable energy may lead to in-state economic co-benefits such as new jobs and spending. In addition, reductions in power sector GHG emissions through changes in demand or dispatch would be expected to reduce emissions of a range of pollutants associated with the fuel(s) and unit(s) displaced. However, these on-system emissions co-benefits may not occur in Oregon. The actual location of these business-as-usual (BAU) emissions benefits depends on the location of the marginal power plant on the western power grid.

Offsets may achieve more or less emissions reductions and/or other co-benefits such as watershed improvements (from sequestration projects), jobs and economic activity. The location of these benefits will depend on how the state defines an allowable offset with respect to geography (see p. 15 for more detail).

Disadvantages
The main disadvantages of an offset program include: 1) the possibility that reductions may not be real, 2) the transaction costs involved in developing rigorous offsets, and 3) the possibility of making future regulation of a sector more difficult if a state initially allows the sector to benefit from participation in trading. We also address the critique raised by some that through use of offsets, emissions reductions will not take place within the power sector.

Probably the biggest concern is that the emissions reductions from offsets used for compliance will not be equivalent to (e.g., will be less than) the emissions reductions that would have been achieved from the capped sector(s). This can happen for any number of reasons, for example, if the baseline allows for "hot air[2]," if the reductions are not

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[2] "Hot Air" refers to emissions credits generated under what might otherwise be considered BAU activities. If baselines are set artificially high, the BAU emissions level may be below the baseline levels, generating emissions credits. For example, emissions credits based on 1990 levels of emissions tend to award these

deemed to be “additional” or “permanent” or if the reductions are not correctly accounted. These and other concerns and possible ways to address them will be discussed later in this paper.

A second disadvantage of an offset program is that transaction costs—costs associated with initiating and completing transaction of a property--are higher than under the allowance trading system. Each project needs to demonstrate the legitimacy of the offsets earned and receive some form of third party and/or regulatory review. The actual requirements can vary from one program to another depending on the desired level of rigor. These costs can range from a few cents to tens of dollars per ton of carbon. Transaction costs are higher on a per ton basis in the case of smaller size projects, distributed projects, and demonstration projects. The issue of transaction costs is treated further on page 34.

A third issue with offsets programs is that in designating certain sectors as voluntary offsets, the state may be creating new political and technical barriers to future regulation of these sectors. Allowing a business to sell offsets creates a financial incentive to undertake reductions. The prospect of future regulation becomes more difficult as the state would both be taking away an incentive and adding a mandate.

A final issue raised by some stakeholders is that in allowing offsets, emissions reductions will not occur from the power sector in Oregon. While this does not matter from a purely climate change standpoint (a reduction of CO2 emissions in Oregon has the same overall climate impact as a reduction anywhere else in the globe), not acting in the power sector could affect long-lived investment decisions. In addition, there will be differences in co-benefits. Power plant reductions in Oregon will achieve emissions co-benefits somewhere in the Western US (thought not necessarily in Oregon), whereas co-benefits in other sectors, whether emissions benefits, watershed impacts, etc. will occur at the site of the project, whether in Oregon, elsewhere in the US, or overseas. In addition, if the goal is to get more experience in power sector mitigation technologies, this would not happen with offsets.

The paper reviews important aspects of designing a credible offset system, including 1) the choice and definition of an emissions baseline, 2) key issues with crediting emissions reductions, including additionality, 3) issues related to the location where credits are generated, 4) issues related to the age and timing of credits generated, and 5) specific issues with creditable actions in several industry sectors. In each case, we review the advantages and disadvantages of alternative offset system designs. And in many cases, we note distinctions between the load-based cap-and-trade system contemplated in Oregon and the more traditional generation-based cap approach. In addition, this paper looks at options for restricting offsets, ideas for treatment of sectors that could be subject to future regulation, and options for lowering transaction costs. Finally, summaries of model offset programs referred to in the text are provided in the Appendix.

"hot air" credits to former Soviet Union countries whose BAU emissions have fallen due to lower production levels.

BASELINE

To properly estimate emissions reductions from an offset project, a project-specific emissions baseline must first be developed. This baseline estimates future emissions if the project were not to take place. The policy scenario then shows how the proposed project is expected to impact emissions. The difference between the baseline and the policy scenario gives an initial estimate of offset credits, with actual offsets determined through the crediting procedure.

The first stop in estimating the emissions baseline for a project is setting a project boundary. This boundary should contain all the project-related emissions including those indirectly impacted by the project.

The emissions baseline should demonstrate the most likely emissions scenario within the project boundary in the absence of the proposed project. The baseline should incorporate the best available information on future technological improvements, new regulatory requirements, such as the likelihood of future carbon regulation, and market expectations. With stable markets and little expected technological change or capital turnover, the baseline can be established simply by a continuation of recent trends. If equipment tends to turn over frequently, a similar project that has recently changed out equipment on a business-as-usual schedule can be used to establish baseline emissions. Importantly, estimating an emissions baseline is more of an art than a science. A best guess is created based on knowledge of the sector and particular state or regional circumstances.

Maintaining realistic baselines avoids the artificial manufacturing of so called “hot air” reductions. Project developers have an incentive to make the baseline case as high as possible so that their projects will be credited with greater reductions.

Projects with greater uncertainty in business-as-usual conditions, those lasting longer than 10 years for example, may be more accurately evaluated if baselines are periodically updated. With a dynamic baseline, it is likely that new technologies or practices will lower the baseline emissions, lowering the number tradable credits awarded to the project over time. On the other hand, unexpected increases in project productivity (i.e. more output at the less-than-baseline emissions intensity) could result in a higher-than-projected baseline. The frequency of baseline updates is an important consideration. Administrative ease must be balanced against the accurate scoring provided by revised baselines and incentives to project creators. The prospect of revising the awarded offset credits might inhibit offset creation, so requirements for baseline revisions should be clearly articulated before project approval and may vary from project to project.

A final wrinkle in baseline development relates to the evaluation of emissions impacts that occur outside of the project boundary (e.g., leakage) that can occur as a result of project implementation. In cases where leakage is a possibility, the project proposal should present the expected leakage issues for consideration and consider utilizing a more inclusive baseline. While direct impacts from the project may be straightforward measurements of fuel savings or improved emissions rates, the indirect impacts may be more difficult to assess. In theory, the policy scenario should demonstrate the likely reductions, including leakage impacts, associated with the project, holding levels of production constant where relevant. For example, benefit estimates from the increased use of biofuels do not just consider the gasoline or diesel displaced, they also account for the CO_2 generated from the production of the biofuel. The impact of these indirect changes in emissions should be included in the project scenario. Similarly, a project that conserves commercial forest land without lowering the demand for wood products will likely result in other forests making up for most of the lost supply. Therefore, the baseline should strive to incorporate forests that may experience an increase in demand to meet supply.

Once the direct and indirect baseline and policy scenarios have been established, the difference between the two cases is the emissions reduction associated with the project.

CREDITING

This section describes the steps to determine whether the emissions reductions calculated for a given project should be approved for the purpose of assisting load-serving entities (LSEs) in complying with their cap. Each offset system has different procedures for crediting, but they all address the fundamental questions of additionality, permanence, monitoring and verification, certification, and ownership.

Additionality

In the simplest terms, additionality is a reduction in emissions beyond that already occurring in the baseline. However, this presumes that baselines are more objective than is actually the case. Another description is that a project is additional if it would not have otherwise occurred except to generate carbon reductions voluntarily. Additionality can be shown by demonstration of reductions beyond baseline reductions or through passing additionality tests.

Theoretically, a perfect baseline would allow for easy demonstration of additionality. If the baseline were able to capture all future reductions in emissions that were made in the business-as-usual case, then any reductions beyond this would be classified as additional. If it were possible to have a high degree of certainty with respect to the baseline, then this approach would work well.

Alternatively, additionality can be proven through a barriers test. This requires identification of a barrier to business-as-usual implementation, followed by a demonstration of how offset certification helps to overcome the barrier.

A number of tests can be employed to determine if a project passes the barriers test. This list, although not exhaustive, demonstrates characteristics that qualify or disqualify projects from being classified as additional.[3]

- Common Practice Test. The proposed project must utilize methods and technologies that produce lower emissions than similar existing projects. Adoption of standard practices is likely assumed in baseline and therefore not additional.
- Investment Test. If the project is likely to make a significant rate of return, then likely it will be in the BAU scenario. If profits from the sale of offset credits are required for financial feasibility, then the project may qualify.
- Regulatory Requirement Test. The proposed project must exceed all emission requirements that it is legally bound to meet. Only reductions beyond these requirements are potentially eligible.
- Technology Test. If the only purpose of adopted technology is to reduce GHG emissions, then reductions can be considered additional.

[3] WBCSD and WRI GHG Protocol for Project Accounting.

- Timing Test. Projects starting before the implementation of an offset program have difficulty in demonstrating that they were created for the purposes of creating offsets (projects previously developed for other offset programs may be granted exemptions). Although this eliminates projects, passing this test does not demonstrate additionality.

These tests are used in conjunction with one another. The common practice test eliminates standard technologies and methodologies from being considered as additional; the regulatory test eliminates required reductions from being considered as additional; the timing test eliminates past projects from being considered as additional, etc. All projects not eliminated must then pass a barrier test (typically financial barrier test) that shows that offset classification overcomes the barriers to project completion.

There is some flexibility in the stringency with which the additionality tests are applied. Too restrictive applications will prevent some worthwhile projects from being implemented, while too loose of an application reduces environmental integrity.

Successful offset programs must be able to distinguish between business-as-usual reductions, and reductions achieved for the purpose of creating offsets. This is especially true in programs where offsets from uncapped sectors are used to meet the requirements of a capped sector. Without stringent rules for establishing additionality, any project that reduced emissions could apply for offset credit, reducing net reductions associated with the cap and impacting the environmental integrity of the offset program. Another way to think about additionality is as a test of exclusion from the baseline scenarios. Thus, emissions reductions from projects that will not occur under likely baseline scenarios comprise the set of potential offsets.

See the Appendix for detailed procedural description on establishing additionality within the Clean Development Mechanism.

Permanence

Given the relatively long life of carbon dioxide in the atmosphere, a pound emitted this year has essentially the same impact as a pound emitted next year and for the next 100-plus years. Thus, projects that simply delay emissions from going into the atmosphere have limited impact. Offset systems therefore should address the permanence of CO2 reductions.

CO2 offset projects can seek credits for reduced CO2 (or CO2 equivalent) emissions or through enhanced biological or geological sequestration. Projects that prevent the burning of fossil fuels cannot be accused of burning fossil fuels, but projects that sequester CO2 may in fact not permanently sequester CO2. For example, enhanced carbon storage through afforestation or reforestation sequestration suffers from the fact that the sequestered carbon dioxide will eventually be emitted into the atmosphere. Furthermore, the storage medium, the forest, is subject to the changing climate it is trying to mitigate. A forest fire may suddenly eliminate all the carbon storage that has taken place or new pests may kill the trees as the climate becomes more hospitable to them.

Similarly, if geologic sequestration experiences leakage, even at a slow rate, the benefit of the offset can be severely compromised.

In other cases, evaluating permanence is more complicated. For example, if forest products are harvested, it is necessary to know how those products will continue to store carbon. Some consumer wood products such as furniture or building products sequester a large portion of the carbon for long periods of time. Other forest products, like biofuels generated from plant and wood material, displace oil consumption. Still others, such as firewood, quickly release carbon back into the air.

In contrast to sequestration, a pound of coal or a gallon of gasoline not burned this year will still not be in the atmosphere next year. Thus, projects that avoid extracting and using carbon-based (fossil) fuels have a greater degree of permanence. Efficiency improvements such as those displacing natural gas in home heating, biofuels and land use decisions (which create more efficient travel patterns) exemplify projects that avoid carbon extraction thereby creating offsets with greater permanence.

Non-permanency can be addressed through discounting, guarantees, delayed awarding of permits, early payoffs of credit values, or by disallowing non-permanent offsets. Discounting is the idea that the conversion of emissions avoided into offsets does not have to occur on a one-to-one basis. Avoided emissions with perceived lower degrees of permanence can be converted at a ratio of greater than one-to-one to incorporate the risk profile. Unfortunately, it is difficult to assess the probabilities associated with the permanence of offsets from sequestration. Uncertainty makes it more difficult to guarantee transactions, resulting in buyers and/or sellers of offsets having to take measures to insure against non-permanency.

Alternatively, offset generating institutions may guarantee the permanence of the offset. Such practices would likely involve holding options for other (permanent) offsets that could be purchased if the original offset project suffers a setback or, in the case of increased forest cover offsets, a sudden CO_2 release due to fire. This would ensure that offsets achieve permanent CO_2 reduction.

Another approach that can be used is to not immediately award full credit for projects. A project that sequesters 1,000 tons of CO_2 may only be awarded 500 credits initially, with another 500 awarded in a future compliance period.

Still another approach to addressing permanence is to require projects to pay off their credit loans every five years. At that time, if the sequestration is still in place, the project can reapply for credit. This approach helps project owners avoid large debts in the event that, say, after 20 years, the forest burns down and they don’t have the resources to pay. This revisiting of sequestration projects on a five-year cycle would undoubtedly increase transaction costs.

A final option is to disallow non-permanent offsets altogether. If the state is dissatisfied with the options to address permanency, a permanency test can be implemented whereby offsets without permanency are left out of the system.

Monitoring and Verification
The monitoring and verification of all greenhouse gas emissions within a project boundary is critical in any emissions trading program. Rigorous, transparent and consistent monitoring and reporting ensures the environmental integrity and credibility of the system and promotes equality within the system. Without it, companies could gain advantage over competitors, undermining not only the integrity of the trading program but the efficacy of it as well.

Within the context of the Clean Development Mechanism (CDM), the United Nations Framework Convention of Climate Change (UNFCCC) defines monitoring as “the collection and archiving of all relevant data necessary for determining the baseline, measuring anthropogenic emissions by sources of greenhouse gases (GHG) within the project boundary of a CDM project activity and leakage, as applicable.”[4]

To ensure a complete and accurate monitoring plan all sources of emissions within the project boundary need to be monitored and reported on a regular basis throughout the life of the project activity. The monitoring plan includes an appropriate methodology indicating how all relevant data will be collected and presented. Calculation of GHG emissions involves identifying GHG emission sources, selecting the methodological approach, collecting relevant data, choosing emission factors, applying calculation tools, and reporting GHG emissions data. All data such as key assumptions, emission factors, oxidation factors, conversion factors, and references etc. are disclosed in the plan.

Once a monitoring methodology is in place, the project proponent will submit regular monitoring reports to an independent entity to verify the results. The UNFCCC defines verification as the “periodic independent review and ex post determination by a designated operational entity of monitored reductions in anthropogenic emissions by sources of greenhouse gases (GHG) that have occurred as a result of a registered CDM project activity during the verification period”. [5]

The purpose of verification is to provide independent assurance that facilities have accurately reported their emission reductions and to maintain the integrity of the system. The independent entity may perform several tasks in this regard including:[6]

- Ensuring that the project documentation is in order
- Conducting on-site inspections
- Reviewing performance records

[4] UFCCC Glossary of Terms: http://cdm.unfccc.int/Projects/pac/howto/CDMProjectActivity
[5] Ibid.
[6] Decision 15/CP.7, Principles, nature and scope of the mechanisms pursuant to Articles 6, 12 and 17 of the Kyoto Protocol
http://cdm.unfccc.int/Projects/pac/howto/CDMProjectActivity/Validate/rules/modproced.html#MP35

- Interviewing project participants
- Testing the accuracy of the monitoring equipment
- Reviewing monitoring results for accuracy, completeness and transparency
- Recommending appropriate changes for future crediting periods
- Informing the project participants of any concerns

When this due diligence is completed with acceptable results, the project participants are provided with a verification report that confirms that during the specified time period, the project achieved the expected amount of emission reductions outlined in the project plan.

Third Party Certification

Once a monitoring report has been verified by an independent entity, the project activity has to be certified in order to receive official approval. Certification is the process of independent evaluation of a project activity by a 3rd party entity against the requirements of the emissions trading system. Certification endorses the existence, eligibility and title of the emission reduction activity and enables it to become a tradable commodity.[7]

Under the CDM, a designated operational entity (DOE) performs both the verification and the certification. The DOE is either a domestic legal entity or an international organization that is accredited and designated by the signatory Parties to the Kyoto protocol. All DOEs must go through a comprehensive accreditation process.[8]

Other trading programs have opted for existing certification institutions such as the International Organization for Standardization (ISO), for this independent auditing role. Aside from the advantage of utilizing an internationally recognizable standards institution another significant advantage is that it decreases the amount of upfront resources needed to get the program up and running.

As an alternative to adopting the CDM or ISO protocols for certification, Oregon could design its own certification methodology.

Key choices that must be made include whether or not to adopt existing certification procedures, and whether or not to allow monitoring and verification firms to also perform certification. Adopting an existing protocol would be an inexpensive option and also facilitate the fungibility of Oregon's offsets with other trading programs should that be desirable.

Enforceability, Serialization and Ownership

Offset credits, once granted, function like any other commodity. They are given serialization numbers to facilitate tracking and establish ownership. Offsets with assigned vintages may be freely traded until they are used to meet compliance and are retired. Offsets created under systems not allowing year-to-year, or compliance period-to-compliance period, transfers simply expire at the end of the compliance period regardless of whether or not they were used to meet compliance.

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[7] CO2eGlossary: http://www.co2e.com/common/glossary.asp#20385

[8] http://cdm.unfccc.int/DOE/acc.html

GEOGRAPHY

Offset programs may have specified geographic boundaries. These boundaries determine where the reductions can occur. Boundaries are set based upon the goals of the cap or reductions targets, and the willingness to tradeoff lower prices for lower co-benefits and less control or certainty. If the goal is to have less net emissions within Oregon, or to get both CO2 reductions and more of the associated co-benefits, then the offset program should be restricted to an in-state program. If the goal is to achieve maximum GHG reduction at the lowest cost, then the geographic boundaries should be more open.

An in-state only offset program, as it has the most limited pool from which to choose offsets, will likely have the highest average price of offsets. However, since all offsets are within the state, there may be greater certainty that Oregon's standards for offset quality will be met. Additionally, by requiring offsets to be in-state, any co-benefits resulting from the project will stay in Oregon. For example, residents would benefit from fewer criteria pollutants emitted as a co-benefit from any reductions in fossil fuel use just as they would enjoy co-benefits from actions within the power sector, or even more so[9]. Similarly, residents might enjoy increased greenery and watershed benefits as a byproduct of increased utilization of biological CO2 sinks, as well as increased economic activity from offset creation while supporting Oregon's climate friendly businesses. The in-state only program results in higher allowance prices with a high degree of control over offset requirements and the maximum amount of co-benefits.

Less restrictive programs could geographically limit offsets to those from either the western region only, or from anywhere in the United States. Although Oregon would not have regulatory authority over the sources that created the offsets, the in-state rules for offset creation, monitoring, verification and certification would apply. Alternatively, Oregon could opt to recognize offsets certified by another program, reducing transaction costs and, potentially, quality control. Limiting the location of offsets to within the west or to the United States would reduce the net national emissions with co-benefits likely occurring in other parts of the country. With the larger project pool, offset prices would likely be lower.

A worldwide offset pool is also possible. While theoretically this could include offsets from anywhere, likely it would take the form of allowing offset credits from the CDM. The offset standards for CDM credits are rigorous, and they are used to help countries comply with their commitments under the Kyoto Protocol. Although these credits would not lower national emissions or result in co-benefits for Oregonians, costs are minimized and the impact on global warming is the same.

The rules regarding geographic scope can incorporate design flexibility allowing for expansion based on designated criteria. The Northeast Regional Greenhouse Gas

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[9] Reductions in fossil fuel use within the electricity sector may generate co-benefits anywhere on the western electricity grid, whereas co-benefits from reduced direct use of fossil fuels within Oregon's non-electricity sectors will distribute benefits primarily within Oregon. Thus, on average, in-state offsets may provide greater co-benefits for Oregonians than electricity sector reductions.

Initiative (RGGI) offset program allows offsets from outside the system once a price trigger is reached. The idea is that within-region offsets are preferred up to some price level. Once the threshold is reached, the burden of meeting the cap is eased by allowing credits from outside the initial region.

Geography poses special problems for the creation of offsets in the power sector under a load-based trading system. Under a load-based system, the cap encompasses a broader boundary than under a generation-based system, including all renewable and non-renewable generation selling power to load-serving entities and all demand-based measures that may occur at the site of power end-users served by load-serving entities. An LSE may, therefore, undertake a range of energy efficiency and renewable energy measures as means of compliance with its emissions cap. Offsets, by definition, must be outside the boundary created by the cap, so cannot include energy efficiency at end users that displaces electricity or renewable energy or other changes in the generation portfolio that is owned by or sold to the LSE. See p.23 for a more detailed analysis of the limited potential for offsets in the power sector.

VINTAGE

Within cap and trade programs, allowances are issued or sold in amounts equal to the cap level. These allowances are tagged with a compliance year, or vintage year, indicating the year they are designed to meet the cap. The limited availability of allowances ensures compliance will be achieved.

As with allowances, offsets are earned in a particular year and could be limited in their use to a particular year or to a limited number of years. The rationale for this is that over time, with changes in technology and regulations, project baselines would change, reducing the value of credits that were previously issued. However, such restrictions, if they can be enforced, would also limit some of the key benefits of offsets, including compliance flexibility and cost savings. Vintage restrictions would also reduce the incentive for actors to earn credits in the state given the higher level of uncertainty of being able to sell the allowance at the desired price. Alternatively, banking can be used with offsets just as it is used with allowances, and for the same reasons.

As a practical matter, unless there are also restrictions on when allowances can be used, if offsets and allowances are fungible, a regulated source will use its more restricted offsets first and simply bank its allowances. The effect is the same as if offsets could be banked.

SECTOR ANALYSIS

This section reviews opportunities and challenges for earning offset credits in the power sector, for terrestrial sequestration in the forestry and agriculture sectors, and for non-power emitting sectors.

Power Sector

While it is possible to estimate emissions reductions associated with energy efficiency and renewable energy measures that displace electricity, and methodologies for crediting energy efficiency and renewable energy offsets have been developed in the context of generation-based emissions caps, ***earning offsets from energy efficiency and renewable energy measures within the power sector would result in double counting of power sector reductions under a load-based trading program and cannot be allowed***.

Under a load-based trading program, energy efficiency and renewable energy comprise core means of compliance with the cap. Renewable energy that is owned by or sold to an Oregon LSE is already reflected in that company's bottom line emissions. Therefore, additional "credit" cannot be granted for these activities. Similarly, to the extent that an Oregon LSE or its customer invests in energy efficiency to reduce the demand of one of its power customers, this will reduce the total amount of power it needs to supply and the emissions associated with that power supply. To the extent that this energy efficiency or renewable energy seeks to earn independent "credit," this would be double counting.

If the energy efficiency and renewable energy project seeking to earn "credit" is not owned by or sold to an Oregon LSE, or is not achieved by a customer of the LSE, then these reductions are technically outside the boundary of the cap-and-trade program. However, granting Oregon offset "credit" for these actions would be problematic as it would reduce the incentive for such resources to be sold to Oregon LSEs for the purpose of meeting the cap, creating a perverse incentive and making it more difficult for LSEs to achieve compliance. In addition, granting Oregon offset "credit" for power sector mitigation actions outside of the cap (and not doing so within the cap) would likely be deemed unfair and would potentially be illegal under the Commerce Clause. ***Therefore, the bottom line is that energy efficiency, renewable energy, and other power sector measures cannot earn offset credit under an Oregon load-based cap, regardless of the location of the mitigation action.***

Although crediting under a load-based cap may not be an option, energy efficiency and renewable energy are automatically advantaged under a load-based cap as they will be in high demand by LSEs needing to meet the cap. Zero-emitting resources have the option of negotiating higher prices for their energy or energy savings. A political decision could be made to further advantage these resources, but we recommend that this not be done by allowing creation of "credits" in these sectors. Possible alternatives would be the creation of a set aside program from within the cap in which a certain number of allowances from within the load-based cap are granted to energy efficiency and renewable energy projects or in which allowances are sold via auction and proceeds benefit energy efficiency and renewable energy projects.

Forestry and Agricultural Sinks

A range of activities in the forestry and agriculture sectors can be used to enhance terrestrial sequestration. A selection of forestry and agriculture offset project types is provided in the table below, along with thoughts on the specific challenges and opportunities each presents:

Activity	Challenges & Opportunities
Afforestation – Establishment of trees on sites not currently forested.	Few tons for 10-20 years. Land value a big factor in the economics. Can reduce cost by thinning. Permanence issues.
Forest health thins – Cutting biomass to enhance forest productivity. Assumes cuttings are used to produce electricity, displacing BAU power resources.	Potential for double counting of electricity sector mitigation actions.
Burying thinnings – Cutting biomass to enhance forest productivity with burial of cuttings in a landfill.	Cost depends on fiber price.
Thin to Reduce Fire – Cutting biomass to reduce the potential for fire.	Preliminary analysis suggests there is little GHG benefit from thinning to reduce fire and that this practice may actually cause net emissions.
Convert hardwood to conifer	No GHG benefit for 10-20 years. Permanence issues.
Extend rotations	No GHG benefit in first ten years. Results sensitive to discount rate. Permanence issues.
Reduce forest loss – Reducing conversion of forest to developed use.	Implemented via development rules. Permanence issues.
Enhance yard trees	Also reduces cooling demand. Permanence issues.
Increase no-till agriculture --	Permanence issues.

Discussion of these and other challenges (e.g., baseline issues, leakage, timing of sequestered emissions) posed by treating forestry and agricultural sinks as offsets are discussed below.

Baseline Issues

First, because land management and terrestrial carbon stocks often change over time under normal conditions, a major difficulty in earning offsets relates to establishment of an appropriate baseline for each project. To establish a baseline for a sequestration project, one must estimate how the carbon stock on the lands would likely have changed had the project not been implemented. The most objective way to do this is to look at what happens to carbon stocks on other lands having similar starting conditions and as they change with the climate.

For example, suppose a landowner implements a sequestration project that sequesters carbon by growing trees on land that previously had been used to grow small grain crops. If all other lands in the vicinity that are used to grow small grain crops remain in small grain crops and sequester no carbon, then all the carbon sequestered within the project boundary counts as an offset (minus emissions displaced by the project to other locations outside the project boundary). However, if all other lands in the region that were used to grow small grains are also converted to trees, then the baseline would be the average sequestration by the trees on these other lands and the baseline carbon stock would rise at the rate of sequestration observed on the non-project lands. It is possible that the baseline can rise as fast as the carbon stock on the project lands. If so, none of the carbon sequestered on the project lands would be above the baseline, and thus none of the project sequestration would count as an offset.

A second baseline issue relates to the potential for displacement of emissions to outside the project boundary (e.g., leakage). To enable assessment of whether a given project resulted in emissions leakage, it is necessary to understand baseline conditions broadly, potentially well beyond the boundaries of the offset project. See below for more discussion of sequestration project leakage.

Third, setting baselines for forestry and agriculture projects requires work and is often expensive. It is challenging to determine what lands constitute an appropriate comparison. And if a project has to pay for quantifying changes in carbon stocks on baseline lands, as well as project lands, the cost can be double the cost of only quantifying changes in carbon stocks on project lands.

To reduce these transaction costs, the State could develop baselines for selected activities occurring in selected regions. These baselines would be available for use by any project of the appropriate type and in the appropriate region. Standard baselines would reduce the cost and uncertainty faced by projects. Also, standard baselines would reduce the opportunity for projects to “game” the system by selecting inputs to calculations to show low baseline sequestration, to have more of the carbon within the project boundary count as offsets. On the other hand, using a standardized baseline may miss project-specific deviations from the average, such as lower amount of sequestration being achieved by selectively enrolling low productivity lands in offset projects. This problem can be avoided by measuring actual project achievements.

A second way to reduce transaction costs for these sectors is through aggregation. Experience by third party verifiers of terrestrial carbon sequestration, the Environmental Resources Trust and Winrock International, show that aggregating lands into blocks of a few thousand acres each can spread measurement costs over large numbers of acres so that the cost per acre can be cents per year.

Project Permanence Issues

A second important issue with respect to sequestration projects relates to project permanence. When the physical sequestration of carbon underlying an offset is reversed (or sooner), the offset must be counted as lost and the amount of the emission counted in the account of the user of the offset. For example, if an offset is created by sequestering carbon by growing trees, and the trees burn and release the carbon back into the atmosphere as carbon dioxide, the offset disappears. Given that carbon dioxide stays in the atmosphere for more than 100 years, at a minimum, terrestrial sequestration would have to match that life-span to be considered permanent.

One way to address the impermanence of terrestrial sequestration offsets is by requiring periodic measurement of terrestrial carbon stocks, and reporting changes in stocks.[10] This reversibility of terrestrial offsets means that they must be monitored to verify their continued existence for as long as they are used for compliance with an emission cap. If an emitter who has used a terrestrial offset as compliance wishes to stop monitoring the offset, the emitter should replace the reversible offset with a non-reversible allowance or offset. Another approach is to allow non-permanent offsets for a limited period, say 5 years, at which point they need to be replaced. This ensures that offset debts stay within a manageable range while also increasing the likelihood that debtors pay what they owe.

If a regulated emitter has surrendered a reversed offset as part of compliance with an emission cap, the emitter that used the offset must book an emission of the amount of the lost offset. Alternatively, emitters could choose to purchase offsets that are guaranteed by the supplier, so that the supplier replaces any offsets that are reversed. Another strategy for dealing with this problem is insurance. If available, insurance could replace reversed offsets with different offsets, or pay for purchase of replacement offsets on an open market.

Leakage in Sequestration Projects

If a project seeks to reduce emissions of forest carbon by stopping ongoing logging, and if the project does not accomplish a corresponding reduction in demand for wood products, then users of wood products will seek timber elsewhere. In most situations, other suppliers will make up most of the shortfall in supply with little change in the price of the good, and thus there is little change in consumption of the good. In the case of timber, this would mean that logging elsewhere would increase in response to a loss of

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[10] This method is used by the California Climate Action Registry.

timber supplied from project lands, and emissions from logging are thus displaced from within the project boundary to locations outside the project.

This displacement of emissions is called leakage. Calculating the net atmospheric benefit achieved by the project requires subtracting leakage from the gross benefit achieved within the project boundary.

The proportion of the reduction in supply of a good that is compensated for by other suppliers depends on the relative sensitivity of suppliers and consumers to changes in the price of the good. The rate of change in the amount of the good supplied as a function of a change in price is called the price elasticity of supply. The rate of change of the amount demanded by consumers as a function of change in the price of the good is called the price elasticity of demand. Over time, the supplies of manufactured goods and renewable resources are relatively elastic. This means that reductions in supplies of goods such as timber are almost completely made up by increased production by other suppliers. For small reductions in supply, the replacement by other suppliers is more complete than for larger reductions in supply that can change prices.

Even the large reduction in timber production on the West Coast resulting from federal protection of the spotted owl resulted in about 85% of the supply reduction being made up by increased production in other regions (Murray et al. 2004). As a result, in Oregon, one should expect that the leakage rate will be at least 85% for a forest conservation project that reduces the amount of timber supplied to markets without making a corresponding reduction in demand.

Calculating leakage of emissions is complicated by the fact that the emission per unit of production of a good may be different for the suppliers that make up a shortfall than for the supplier undertaking climate mitigation actions. For example, if a project reduces timber harvest from a mature forest, it could displace timber harvest to a forest in a developing country, where inefficient logging practices result in greater emissions per cubic foot of timber produced. Alternatively, displacement could result in a reduction in emissions, even if the total amount of goods produced remains the same. For example, timber harvest could be displaced from a native forest with high emissions per cubic foot of wood extracted, to intensive plantations that have lower emissions per cubic foot of timber produced because the plantations have less carbon emitted from stumps, branches, and non-merchantable trees per cubic foot of timber extracted. Estimating whether leakage increases or decreases emissions requires careful analysis of the dynamics of the market for the good in question, and careful analysis of emissions per unit of production in locations to which production is displaced.

Project Timing Issues

Another issue with sequestration projects is the fact that in many land use and forest projects, the costs and benefits occur at different times. For example for afforestation projects, most of the costs occur in the few first years of the project, but most of the sequestration benefits do not occur for decades. In terms of deciding whether such a project should be pursued, emissions reductions benefits can be awarded on a yearly basis as the carbon is sequestered or levelized using the social discount rate and compared with other prospective offset projects on a cost per ton basis.

Some Final Considerations

When considering whether it is worth the effort to allow forestry offsets, policy makers should consider whether or not many landowners are likely to participate in a voluntary program when offset prices are modest. For example, when development value for forest land exists, or when a fair amount of merchantable volume of timber exists on a property, few landowners will be willing to commit to increasing forest carbon stocks and holding these increased stocks for ever, unless the offset price is extremely high. This is because at low offset prices the per-acre value of offsets would be small relative to the per-acre returns possible from other uses such as development or logging.

If maintaining the carbon sink is perceived as limiting land management options (such as limiting the opportunity for the landowner to sell the land for non-forest use or draw down standing timber volumes), few landowners will be willing to voluntarily take actions for payments that are only a tiny fraction of the value of the land plus existing timber. For example, even if a landowner could store an additional 50 tons per acre and get paid $10 per ton ($500 per acre) few landowners would be willing to commit to this on an acre of land where the land and timber are worth $10,000 (or possibly much more), and where the sequestration contract is perceived as reducing the future value of the land. Afforestation projects might not have this problem because the per-acre value of offsets can be substantial relative to the price of land.

Non-Power Emitting Sectors

Issues that should be considered in determining eligible sectors and projects from non-power emitting sectors include: 1) whether the chosen project mitigates direct or indirect electricity-related emissions; 2) whether the sector may be a candidate for future regulation; 3) the potential for accurate measurements of emissions reductions, and 4) whether offsets are likely from that sector given the expected transaction costs.

A first consideration in allowing credits from non-power emitting sectors is whether a given offset project mitigates direct or indirect electricity-related emissions. A range of measures can be taken by non-power emitting sectors to mitigate greenhouse gas emissions associated with on-site fuel consumption or production of non-CO2 greenhouse gases. Such measures are potentially eligible offset projects. However, measures that achieve GHG mitigation from reductions in grid-based electricity consumption may not be credited due to the potential for double counting under a load-based trading system. (See the power sector section for discussion of this issue.)

A second issue with non-power emitting sectors is whether the sector may be a candidate for future regulation. Depending on the stringency of the Oregon state GHG target and the emissions reductions achieved from the power sector, it is possible that additional reductions from other emitting sectors will be needed in the future. Therefore, it may not be desirable to treat such sectors as pure offsets now. This set of issues is discussed in detail on page 32.

A third issue relates to the potential for accurate measurements of emissions reductions. Certain sectors such as landfills and biodigesters cannot easily measure total emissions, which are diffuse, but can measure emissions reductions achieved in combusting methane to CO2. As a result, while these sectors are not good candidates for future participation in a cap-and-trade program, they are strong contenders for inclusion in an offset program.

Finally, an issue affecting smaller sources such as the residential and commercial sectors as well as small businesses, is the issue of how to minimize transaction costs so that they don't pose a barrier to entry. This topic is discussed on page 34.

OPTIONS FOR RESTRICTING OFFSETS

To the degree that there is a need to balance concerns about offset quality and (over)use with the desire by industry for added compliance flexibility, Oregon stakeholders might consider various middle ground solutions that allow offsets on a restricted basis. While there are many potential middle ground designs, three approaches are described here, including: 1) limiting offset use to a percentage of compliance, 2) limiting offset use with trigger prices, and 3) setting restrictive standards for offsets.

Limit Offset Use to a Percentage of Compliance

If a big concern is to ensure that at least a portion of emissions reductions needed to meet the cap are achieved within the regulated sector(s), offset use could be limited to a percentage of a regulated entity's total allowance submittal requirement or a percentage of compliance with the cap. The first approach was proposed in the McCain-Lieberman bill, which allowed a covered entity to satisfy up to 15 percent of its total allowance submission requirement with registered mitigation and/or sequestration offsets. In the latter instance, if a source emits 100 tons of CO2 and is capped at 80 tons, a rule could be established that up to half of the 20 tons of reductions needed to achieve the cap (i.e., up to 10 tons) could be met with offsets. The allowable offsets in the RGGI draft rule are capped at 3.3% prior to price triggers being activated, which is approximately a third of the reductions needed to meet compliance, with elevated amounts of five and twenty percent of a budget source's CO2 emissions allowed at the first and second price triggers.

Limit Offset Use with Trigger Prices

A second approach proposed in the RGGI context is to limit offset use to when the need for lower cost compliance options is likely to be greatest, specifically, when allowance prices are "too high." The allowance price could be set at a cost level deemed to be "unacceptable" and could rise with inflation over time. In RGGI's case, there are two trigger prices ($7 and $10/ton), each one opening a greater set of offset opportunities in terms of 1) the share of emissions that can be covered with offsets, 2) the geographic boundaries within which offsets can be created, and/or 3) the rate at which out-of-region offsets are discounted.

Set Restrictive Standards for Offsets

A third approach for restricting offset use is to establish restrictive standards for earning offsets with respect to additionality, permanence, monitoring, verification, and certification, as well as geography, vintage, early reductions, allowable sectors, and/or independent contributions for the environment. For example, the state could choose to disallow offsets from outside of Oregon or disallow emissions banking simply to minimize offset use out of concern that despite safeguards put in place, offset quality will still be less than the quality of allowances. Each of these design issues is discussed separately elsewhere in this background paper.

TREATMENT OF SECTORS SUBJECT TO FUTURE REGULATION

In order to meet state climate goals and/or any future federal climate targets, it will later be necessary to regulate additional sectors beyond emissions from electricity use. One concern that has been raised with respect to offsets is that by allowing a given sector to participate in a trading system as a voluntary offset, it will later be more difficult to bring them in as a regulated participant. This has proven to be the case in the international context, where developing countries participating in the CDM are now resisting mandatory participation in the second phase of the program and seek to maintain access to CDM projects. The high value of CDM projects creates a new barrier to regulation that didn't previously exist.

A potential solution, then, is to signal that a given sector may in the future be subject to requirements. This could be done in a variety of ways, for example, by 1) assigning sector baselines, 2) mandating an independent contribution for the environment, or 3) setting a sunset date for offset participation.

Assign Sector Baselines

A first approach to signaling that all sectors need to contribute to the climate solution is to establish sector baselines for future regulation. Only reductions that go beyond the sector baselines are credited as offsets under the load-based cap. In using a sector baseline, rules are established for entire sectors rather than individual sources of offsets. This can be accomplished in several ways. For example:

- Individual sources can score their reductions every three years. If enough sources have made reductions that the sector as a whole is below its benchmark, each participating source earns proportional offset credits. While this approach ensures that emissions are reduced from the sector as a whole, there is reduced certainty as sources do not know whether their mitigation actions will lead to credits.
- The sector benchmark is allocated across participating sources. Sectors that reduce below the benchmark are awarded with credits, while those that are above the benchmark are penalized. While encouraging actions in new sectors, this approach applies a mandatory incentive/disincentive to all sources within covered sectors.

Require Retirement of a Percentage for the Environment

A second approach to signaling that all sectors need to contribute to the climate solution is to require that a percentage of all reductions filed for credit from these sectors (say, 50%) must be retired for the environment, contributing to meeting the state target. This approach could avoid the need for generating sector-specific cost curves or other justifications that would underlie development of sector baselines. However, like the sector baselines, such effective discounting of credits would lower the incentive for these sectors to participate in the offset program.

Sunset Date[11]

A third approach to signaling that all sectors will ultimately need to contribute to the climate solution is to offer participation as an offset for a limited amount of time, subject to potential evaluation and renewal. Under this approach, it would be necessary to allow sources to participate long enough that they will have enough time to consider and implement offset projects. A sunset date could also be combined with the other scenarios described above. While a sunset date would streamline offset participation while recognizing the potential for future regulation, politically, it may be difficult to enforce.

[11] Concept suggested originally by Mike Burnett, the Climate Trust.

OPTIONS FOR LOWERING OFFSET TRANSACTION COSTS[12]

Offset transaction costs are costs associated with initiating and completing a transaction of property, in this case, an offset. Components of transaction costs for a given offset project may include project search costs, feasibility study costs, negotiation costs, insurance costs, regulatory approval costs, and monitoring and verification costs. These costs can range from a few cents to tens of dollars per ton of carbon. Transaction costs are higher on a per ton basis in the case of smaller size projects, distributed projects, and demonstration projects. Costs are lower for broad programs, greenfield projects, and under mature markets. In raising costs of participation in offset trades, transaction costs lower trading volume.

Transaction costs are a concern both for state officials tasked with administering a program and for offset participants. These costs can be lowered by 1) providing standardized baselines and methodologies for specific source types, 2) allowing small source projects to be aggregated, and 3) reducing consultation requirements such as allowing less frequent monitoring.

Standardized Baselines and Methodologies.
To reduce transaction costs for offset participants[13], it may be desirable for the government to provide some sort of systematization and comparability in the methodologies used to prepare baselines across different categories of emitters and different types of emission reductions. In particular, a quantification protocol that defines the baseline, boundary, leakage, monitoring, reporting and quantification of emission reductions can significantly reduce the cost of validating proposed projects. However, even within similar projects involving the same roughly classified emission source category, it should be recognized there is no single method of calculating the baseline that is necessarily appropriate. In choosing a methodology for the baseline, there will be a tradeoff between consistency (which improves environmental integrity and reduces administrative system costs) and flexibility (which can reduce participants' costs by allowing them to use appropriate--but different--protocols or develop appropriate alternative methodologies.

Building off of existing methodologies[14] and other program designs[15], Oregon can evaluate the baseline requirements and methodologies recommended elsewhere and learn from these experiences in designing standardized approaches for crediting offsets in specific industry sectors. Given the industry sectors in the state, top priorities may include specific project types in the forestry, agriculture and waste sectors. Based on stakeholder priorities, CCAP will provide alternative approaches for developing standardized baselines in advance of the June discussion.

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[12] This section borrows heavily from Sathaye, Jayant and Eric Smith, "Transaction Costs of GHG Emission Reduction Projects: Preliminary results," US EPA, power point presentation to the Snowmass EMF Conference, August, 2003.
[13] While reducing costs for participants, development of standardized baselines and methodologies would increase transaction costs for government.
[14] For example, the WBCSD and WRI GHG Protocol for Project Accounting.
[15] For example, the RGGI draft model rule, CDM, CA CCAR, etc.

Aggregating Small Sources[16]

Small sources such as individual residences, commercial enterprises, and small businesses may be discouraged from participating in an offsets program because the high transaction costs outweigh the value of the offsets earned. At the same time, these sources have the opportunity to reduce greenhouse gas emissions that could be encouraged via an offsets program. To encourage reductions from small sources, it is necessary to identify ways to streamline the process that don't compromise offset quality.

Allowing aggregators to combine numerous small projects can save time for the state while facilitating participation in the offset program by the residential, commercial and transportation sectors. Through aggregation of small sources, it is possible to 1) spread the transaction costs of an offset transaction across a larger quantity of reductions, 2) diversify the risks of non-performance (i.e., failure to deliver emission reductions) across multiple independent projects, and 3) capture economies of scale by standardizing project selection procedures, contracts and monitoring and verification methods, and by developing a high level of specialized expertise in emission marketing. Aggregation could be achieved through intermediaries, such as ESCOs, investment funds, or marketing "pools" to aggregate emission reductions from multiple projects and deliver transactable quantities to the market. A variety of organizations could serve as aggregators, including government organizations and electric utilities.

Reducing Consultation Requirements

A third way to reduce transaction costs and encourage participation in an offset program by small sources is to reduce consultation requirements, such as requirements for validation and the frequency of monitoring and reporting. These requirements could differ depending on the size of the project. On the other hand, if the objective is to maintain the integrity of the cap, there should not be shortcuts for any offset provider

[16] This section draws on CCAP's May 2004 paper, "Issues and Some Options for Aggregating Greenhouse Gas Reductions from Small Sources."

APPENDIX: OTHER OFFSET PROGRAMS

The Clean Development Mechanism

Under the terms of the Kyoto Protocol, countries are categorized based on their level of industrial development. Fully industrialized countries, classified as Annex I countries, which have adopted the Kyoto Protocol, have immediate CO2 reduction responsibilities whereas developing countries do not. As a result of these differing emission reduction responsibilities, and because developing country technologies tend to be less efficient than those used in developing countries, the cost of reducing the marginal unit of CO2 is often lower in the developing country. Article 12 of the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC) established the Clean Development Mechanism (CDM) to allow Annex I countries to take advantage of the less expensive reductions while also promoting the development of sustainable carbon efficient economies in developing countries. Through CDM, Annex I countries are able to meet their own reduction responsibilities through certified emission reductions (CERs) generated from CO2 emission reduction projects undertaken in developing countries. Demand for offsets from CDM projects is expected to exceed 400 MMTCO2e per year.

A summary of the steps necessary for establishing offsets within the CDM is provided below:

1. Development of a Project Design Document. This document provides:
    - A description of the project
    - A baseline that illustrates business as usual emissions
    - A methodology for monitoring performance and leakage
    - An estimate of project savings
    - An environmental impact assessment
    - Estimated project duration (seven, ten or thirty years)
    - Stakeholder comments

2. Project Validation.
    - CDM Executive Board accredits a designated operational entity (DOE) to perform validation, verification and certification services.
    - DOE verifies the information in the project plan. They verify consideration of environmental impacts, solicitation and inclusion of stakeholder input, methodology and monitoring plans comply with CDM requirements, voluntary participation of parties, and additionality (see below for more on additionality within the CDM)

3. Registration.

- DOE submits validation report, comments from Stakeholders and responses, notice of host country agreement and assessment of the likelihood that offsets will actually be achieved.

4. Monitoring.
   - Monitoring must include estimated impact of project including secondary increases (leakage).
   - Report on potential sources of information to track leakage.
   - Data to evaluate baseline and environmental impacts
   - Procedures for addressing quality control and leakage
5. Verification and Certification
   - Certification is done by a DOE other than the one responsible for the validation
   - Certification report must include data, inspection and monitoring documentation
   - The DOE will verify calculations and methodology and that the project follows the specification laid out in the proposal
   - DOE then provides certification, and requests CDM Executive Board issue CERs for verified emissions reductions
   - Executive board then automatically issues CERs unless a request for review is made

As additionality is key to the integrity of an offset program, the details of establishing it may be of interest. As described in the technical guidance for the CDM, additionality can be established by taking the following steps:

1. Preliminary Step (step 0) Provide evidence that CDM incentives are important in project development
2. Identify realistic and credible alternatives to the proposed CDM project (step 1) If no alternatives to the project are viable, then the project cannot be classified as additional.
3. Financial Barrier Analysis (step 2) The sale of CERs must be shown to be an important contribution to project viability (unless step 3 is passed)
4. Barrier Analysis (step 3) The project should face barriers that would prevent its implementation without the assistance of the Annex I country (unless step 2 is passed). Potential competing projects cannot be subject to the same barriers.

5. Identification of Common Practices (step 4) If similar projects have already been implemented (excluding CDM projects), then the project is not classified as additional.
6. Explain how classification as a CDM project will provide benefits to help overcome the barriers identified in steps 2 or 3. Benefits can include: GHG reductions, CERs revenue, attracting new capital or players, development of new technology, or reducing inflation, exchange or other risks new investors might face.

Once these steps are met, the project can be classified as additional.

http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf

Carbon Sinks as offsets are allowed under the CDM, but their use is limited. Annex I countries are allowed to use CERs generated from afforestation or reforestation or other demonstrated sink equivalent to one percent of their base year emissions in each of the five years of the commitment period. There are separate guidelines for afforestation and reforestation programs.

Note that the guidelines described above are applicable to large scale offset program expected to yield 400,000 or more emission reduction credits. For smaller scale projects, a simpler methodology using the same structure is employed.

While the US has not ratified the Kyoto Protocol and cannot sell allowances into the Kyoto market in the 2008-2012 period, US companies have the option of purchasing allowances or CDM credits from willing sellers.

WBCSD and WRI GHG Protocol for Project Accounting

Although not associated with a particular offset program, the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI) provide general guidance on the development of an offset program.

Their key steps include:

1. Establishing a baseline. The first step in measuring the impact of a project is forecasting where the emissions would have been without the project. The difference between the original forecast and the project forecast are the reductions attributable to the project.
2. Demonstration of additionality. To qualify as an offset, any potential project should demonstrate that it results in emission reductions beyond those achieved in a business-as-usual scenario.
3. Identification and inclusion of secondary impacts. In addition to the direct emission impacts of a project, accurate offset crediting requires that the secondary impacts of the project also be evaluated. Both upstream and downstream impacts

should be netted out of the impact. They note however that limited information might prevent the full accounting of the project.

4. Consideration of reversibility. Offsets, especially those designed to remove carbon dioxide for the air, may have limited life spans. Terrestrial sequestration projects are especially susceptible to this risk as harvesting or forest fires can release the carbon stores. Less susceptible are projects that involve reduced fuel consumption through land use or efficiency.
5. Avoidance of double counting. The ownership rights for offsets need to be clearly defined as belonging to source or sponsor from the outset of the project to avoid double counting.

Once an offset is created, the task is then to convert the offset into a credit within the trading scheme.

They also recently release a report issuing guidelines on project specific GHG accounting. This report can be downloaded at: http://climate.wri.org/ghgprojectaccounting-pub-4039.html

The Climate Trust

The Climate Trust, an Oregon-based non-profit organization, purchases offsets. Most of its funding comes from energy facility developers who have to meet a state siting regulation that requires carbon dioxide offsets. The Climate Trust serves as a mechanism that helps to implement the state standard. Climate Trust offset purchases must meet broad statutory criteria.

The design parameters of the Climate Trust offset program resemble those used in the CDM. Important design factors include additionality assessment, permanence of reduction, rigorous monitoring and verification. Additionality can be proven through a barriers test showing that the Carbon Trust's funds are used to overcome barriers to implementation. These barriers include investment barriers such as lack of debt financing, lack of capital access due to risk; technological barriers such as first adopter in area, limited supply of trained labor, lack of infrastructure; and other barriers such as management knowledge or environmental benefit uncertainty. Once additionality is established, a rigorous baseline that demonstrates emissions with and without the project should be developed so as to score reductions from the project.

Based on these guidelines, the Climate Trust has funded a number of projects including a paper manufacturing efficiency upgrade, building efficiency, wind power financing, reforestation, cogeneration projects, carbon efficient cement project, truck stop electrification and traffic signalization. They have contracted for delivery of more than 1.6 MMTCO2 offsets to date.

The Climate Trust is the leading provider of offsets purchased to achieve compliance with Oregon's CO2 emission standard for new energy facilities. This standard sets CO2 efficiency standards for power generators, that if not met require the purchase of offsets or payment of a fixed amount per ton of CO2.

Massachusetts Offsets Program
Massachusetts has developed a plan to include offsets within their output based electricity sector cap. Offset credits can be generated from emission reductions, avoided emissions and sequestered emissions. Initial sectors eligible for offset creation include landfill gas, SF6, direct fuel use efficiency for natural gas/oil/propane, afforestation. Other potential offset creation opportunities may be added including sustainable forestry management. Ineligible sectors include over-compliance with the cap, nuclear power generation, and underground or underwater sequestration.

Offset certification requires that the reductions be real, additional, verifiable, permanent, and enforceable. Initially, the offsets are geographically limited to Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, although a price limit may remove the geographic restrictions.
The process for obtaining certification of an offset begins with a facility applying for credits from a future or past project. The application is judged against the criteria outlined above. Future credits can be certified if they meet criteria listed. Verification insures that the emissions have actually been avoided. Offset credits must be verified prior to use.

Allowances from other sectors or regions may be accepted as offsets depending on the sustained price. If credit price exceeds an average of $6.50 a ton for a year or if insufficient credits are available, then additional credits will be allowed. Potential external offsets include EU Emissions Trading Scheme Allowances and CDM Certified Emission Reductions or reductions from other approved programs. Once these external allowances are permitted, they will be eligible henceforth.

If prices reach $10 a ton and with the approval of the Massachusetts Department of Environmental Protection (MassDEP), affected utilities can make payments into a GHG expendable trust at a set rate of $10 ton to meet their offset requirements. This trust will fund GHG reduction projects and purchase GHG offsets at lowest cost, with Massachusetts based reductions favored when costs are similar.

RGGI
Offsets are also being considered within the context of the proposed Regional Greenhouse Gas Initiative (RGGI) electricity sector carbon cap. The RGGI proposal adopts many of the same principles outlined in the Massachusetts program, with a few differences that are outlined below. A September 2005 meeting of the RGGI stakeholders provided the initial outline of the offset program, with a March 23, 2006 model draft rule recently submitted for comment.

Eligible offsets are similar to the Massachusetts program. Initial sectors eligible for offset creation include landfill gas, SF6, direct fuel use efficiency for natural gas/oil/propane, afforestation with the potential to add other offsets creation sectors including sustainable forestry management. RGGI also includes a similar price trigger outlined by the Massachusetts plan. The RGGI offset program initially caps the total amount of offsets at 3.3 % of total source emissions until price trigger is reached. At the first price trigger of $7.00, offsets are allowed at a level equal to five percent of the source emissions. At the second price trigger of $10, offsets are allowed at five percent of the source emissions for the first three years of the compliance period and twenty percent after the first three years. Compliance is met over a three year period.

Offsets within the RGGI program follow the protocol developed for the Massachusetts program. To be certified, the offset must be real, additional, verifiable, permanent, and enforceable. Additionality will be assessed through an up-front standardized benchmark for each offset type, thereby limiting discretion in the acceptance or rejection of offsets. Individual projects must establish eligibility, develop baselines and estimated reductions, and meet monitoring and reporting requirements. Other requirements may be added depending upon offset type. Projects must pre pre-approved with credits issued based on demonstrated reductions.

The March 23, 2006 model draft rule for the RGGI trading program (http://www.rggi.org/docs/public_review_draft_mr.pdf) outlined the details of project application procedures, specific offset standards and third party verification issues. The document discusses the procedures required for particular offset projects including landfill methane, SF6, sequestration, energy efficiency, agricultural methane projects.

Offsets under the RGGI program are expected to be 0.4% (550,000 tons) of the emissions budget in the first compliance period, ramping up to 8.3% (11,450,000 tons) in the fourth compliance period.