CARBON ALLOCATION STANDARD TASK FORCE BACKGROUND PAPER[1]

Introduction

At the recommendation of the Governor's Advisory Group on Global Warming, Governor Ted Kulongoski has adopted a goal for Oregon to arrest the growth of greenhouse gas emissions by 2010, to reduce the greenhouse gas emissions to 10 percent below 1990 levels by 2020, and to reduce them to levels 75 percent below 1990 emissions by 2050.

A declining limit on greenhouse gas emissions, as in a load-based greenhouse gas (GHG) allocation standard (or carbon allocation standard), is the most effective action that could reasonably assure that annual Oregon GHG emissions associated with electricity are reduced below the 1990 levels. Reductions of GHG emissions from mix of new and existing power plants supplying Oregon consumers are needed to meet this goal, along with increased energy efficiency. A carbon allocation standard could also reduce the risks to Oregon's utilities and ratepayers of likely future GHG regulations affecting coal plants in particular.

Clear long-term guidance on the rate of reduction in GHG emissions from the electricity sector is needed for utility planning. Some older western coal-fired plants will be almost 100 years old in 2050. Without new regulations, these plants might continue to operate past 2050. Utilities are considering retrofits at coal plants to reduce emissions of criteria pollutants (e.g., subject to Clean Air Act constraints) and mercury. If utilities face clear GHG emission limits in the near future, which will decline over time, they can avoid wasting money upgrading the oldest coal-fired power plants and later having to shut them down because of GHG constraints. They can also clearly evaluate the economics of new coal-fired plants in the face of declining carbon limits.

To stabilize CO_2 concentrations in the atmosphere at a level below double pre-industrial levels (560 ppm), world-wide CO_2 emissions will have to be reduced by 60 to 80 percent this century. The limits of a carbon allocation standard could be designed to provide the appropriate trajectory of utility emissions for the 21st century. The initial allocation could be near existing emission levels. The allocation would be reduced on an established, predictable curve through 2050 to achieve the Oregon greenhouse gas emissions reduction goals the Governor has set.

Load-Based GHG Allocation Standard

Richard Cowart, director of the Regulatory Assistance Project, has described the essential elements of a load-based GHG allocation standard in the electricity sector. The explanation in this section is based on his paper[2]. A GHG allocation standard would make initial allocations to the demand side of the electricity system – to the distribution companies or other "load-serving entities" (LSE) that generate their own power or purchase from generators and supply power to ultimate customers. "Load-based" in this context does not mean each and every retail electric customer, but rather the much smaller number of investor-owned and publicly-owned

1 Concepts borrowed and modified from the Regional Greenhouse Gas Initiative and the Governor's Advisory Group on Global Warming.

2 Cowart, Richard. "Another Option for Power Sector Carbon Cap and Trade Systems—Allocating to Load," Concept memo, May 1, 2004.

distribution electric companies or other retail providers who are responsible for providing electric energy and capacity to end-users.

The load-based allocation standard would be a "hard cap" system, based upon a state determination of total permitted emissions, followed by an initial allocation of credits, and ongoing trading of the credits the state issued. It opens up a broad set of possible actions, many of which are within the authority of electric service providers, portfolio managers, and end-use customers – including switching to different forms of generation (e.g. from coal to gas-fired), choosing renewable supplies, and investing in end-use energy efficiency.

Each LSE would be obliged to secure GHG credits during each accounting period to cover its customers' combined contribution to regional GHG emissions during that period from use of electricity. LSEs acquire resources in a variety of ways: by running owned-generation, by purchasing from affiliates or others in the wholesale market, or by investing in energy efficiency and other DSM resources with their customers. The LSE would be obliged to secure credits to cover its share of emissions from all of these sources, regardless of ownership or location (in other words, emissions from imported power would be tracked and counted just like emissions from generators in the state).

Cowart noted that there are two ways to allocate emissions allowances: by auction or by free distribution to the LSEs. For political reasons, he assumes that allowances will be distributed for free. He then notes that there are different ways to determine the allocation for each LSE. One possibility is to award initial allocations on a grandfathered basis, so that on Day 1 of the system, each LSE has exactly enough credits in hand to cover the emissions to meet its historic power supply needs. Another option is to award credits on an average MWh basis, which would give "clean" LSEs a surplus of credits, which LSEs with worse supply mixes would need to purchase. A variant on this scheme would award credits on an adjusted-MWh basis, giving some extra credit to LSEs where historic efficiency investments had already reduced MWhs and emissions. Another variant would be to have the allocation based partially on emissions and partially on MWh.

By assigning responsibility for limiting total GHG emissions to LSEs, a GHG allocation standard would give responsibility to the entity that is in the best position to make the portfolio management decisions, including decisions to invest in energy efficiency, that are most likely to lower GHG emissions rapidly, and at low cost.

Alternate Approaches to Limiting GHG Emissions

Generation-Based Allocations. Nine Northeastern and Mid-Atlantic states have proposed a regional cap-and-trade through the Regional Greenhouse Gas Initiative (RGGI). The proposed RGGI system would allocate CO_2 allowances to individual power plants within the participating states.

The situation in Oregon is different from a New England state. Allocating allowances only to power plants located in Oregon would not reflect the true impact of emissions associated with electricity use in the state. Our direct state emissions from generation are only about one-third of the emissions associated with our use of electricity. Furthermore, looking only at generation in state by utilities could be inequitable to Oregon's two largest utilities. Portland General Electric has most of its fossil-fueled generation facilities that it owns in Oregon, while most of PacifiCorp's plants are in other states. Another problem with allocating allowances to in-state plants is that it might encourage new power plants to be built outside of Oregon as the level of the allowances issued decreased significantly below current levels. If so, this might harm Oregon's economy with no reduction in GHG emissions.

Renewable Portfolio Standard (RPS). The fraction of load-growth met by renewable resources could be increased by adopting an RPS for Oregon electric utilities and other retail electric suppliers. Another limited approach would be to expand the 0.5 percent renewable portion of the public purpose charge applied to PGE and PacifiCorp retail electric bills from SB 1149 (1999 session).

An RPS could serve as a strategy to implement a load-based carbon allocation standard. If applied in support of a load-based carbon allocation standard, an RPS could help provide a better balance in the types of renewables. Alternately, an RPS, together with Oregon’s existing public purpose funding mechanism, can help achieve a mix of renewable development, at least for investor-owned utilities.

An RPS might reduce the rate of increase in emissions, but not reduce total emissions. On the other hand, an RPS that acquires more electricity than is needed for load growth would necessarily back down existing generating plants, either utility-owned or purchased. For example, having a 15 percent RPS by 2025 (as percent of 2025 load) would reduce Oregon’s annual carbon dioxide emissions between 3.6 MMT CO_2 (if it had the effect of banning new coal-fired power plants), and 2.8 MMT CO_2 (if it did not). A 25 percent RPS would fulfill all new base-load requirements and displace some existing gas- and coal-fired generation under the energy efficiency case forecast of one percent annual load growth. Estimated savings would be 7.0 MMT CO_2 in 2025.

An RPS is generally designed to address only new power plants that serve load growth. Emissions from existing plants would be better addressed within a load-based cap and trade system. Unlike a stand-alone RPS, a load-based allocation system recognizes that new gas-fired generation may serve to reduce overall average emissions from electricity generation and may also help integrate new, intermittent renewable generation such as solar and wind. But, a load-based allocation system could provide substantial incentives for renewable resource development. This could make a separate RPS unnecessary, or an RPS could be incorporated as one tool to assist energy suppliers in complying with the allowance curve.

Emissions Portfolio Standard (EPS). Another allocation system would set limits only on the emission rates (pounds of CO_2 per kWh for each load-serving entity) rather than total CO_2 tons emitted during a reporting period. This is referred to as an emissions portfolio standard. While more comprehensive than an RPS, an EPS does not absolutely limit emissions and would not incorporate emissions reductions from energy efficiency actions. It is a “soft cap,” because it grows with the load. It may also be more difficult to incorporate trading of allowances under an EPS.

Program Goal

The goal is to reduce long-term GHG emissions from utility-supplied power and fuels and major stationary sources to levels consistent with the overall state 2050 goal of being 75 percent below 1990 levels. A secondary goal is to capture and reinvest or equitably distribute economic benefits from energy efficiency and renewables. The Task Force will develop a state (or multi-state) carbon allocation standard covering greenhouse gas (GHG) emissions. The standard will limit emissions from the mix of electricity sources, from natural gas use and from stationary petroleum uses if possible. The program will, at a minimum, initially be aimed at developing a program to reduce carbon dioxide emissions from power supplied (load) to consumers in the state, while maintaining energy affordability and reliability and accommodating, to the extent feasible, diversity in policies and programs.

This standard would limit total amounts of CO_2 and other greenhouse gas emissions caused from consumption of electricity, petroleum and natural gas by Oregonians in homes, buildings and factories. It should produce reliable, equitable and verifiable reductions. The Task Force will provide the Governor with its recommendation in time for legislative action, if necessary, in the 2007 session.

Guiding Principles for Program Design

1. The program will build on successful carbon allocation standard programs already designed or proposed elsewhere.
2. The program will be expandable and flexible, permitting it to encompass other major emission sources and types.
3. The program will start simply and develop over time. The initial phase of the carbon allocation standard program will entail the allocation and trading of carbon dioxide allowances for electric utilities and self-generators at a minimum.
4. The program may serve as a platform and draft for the implementation of future additional emissions trading programs and initiatives that individual or multiple states might join.

Policy Issues

A. Scope — Determine whether the initial limit should be applicable to CO_2 only or should include other greenhouse gases.

B. Definitions — List key terms defined in the statute.

C. Statement of CO_2/GHG Budget — Determine the annual statewide emissions budget for CO_2 and other GHG stated in tons of CO_2 equivalents and its rate of decline.

- Determine the appropriate limit for the state in total and for each utility or self-generator
- How will the standard be phased in over time?
- How will the allowances decline over time?
- Basis for the limit? Baseline or base-year assumptions?

- Should there be provisions to allow for the adjustment of the limit or its rate of decline?

D. Applicability — Define criteria defining the energy suppliers that will be covered under the allocation standard (affected utilities and self-generators).

  - How will standards and be applied to diverse energy sources (electricity, natural gas, petroleum) and suppliers (including consumer- and investor-owned utilities, non-utility suppliers and self-generators)?
  - How will the standard be applied to the electricity sector?
  - Should compliance curves be identical for all suppliers or different to reflect different supplier circumstances?
  - How will the standard apply to natural gas and petroleum suppliers and large industry users of those fuels?
  - How will switching of end uses between different fuels or suppliers be handled?
  - How will new self-generators or retail energy suppliers be handled?
- Should other significant non-energy emitters of GHG (e.g. industrial emissions) be incorporated into this mechanism, or will they require a different one?
- Size threshold for the facilities covered under the limit in calculating the mix?
- Should the allocation standard system include "Opt In" provisions for companies that not covered but that may want to participate voluntarily? Under what conditions?

E. Allowance Allocation — Define the allocation procedures for suppliers covered under the standard and for any set aside accounts if applicable (such as public benefit set asides and new load serving entities (LSE)).

- What allowance allocation system should be used? Auction? Grand-fathering without charge? A combination of auction and grand-fathering?
- How should the amount of allocation be determined—recent emissions contributions for each LSE, recent MWh, adjusted MWh, credit based partially on MWh and partially on emissions, per capita sales, or some combination?
  - If an auction is used how would the proceeds be distributed?
  - How can allocations be accomplished without creating barriers to entry for new sources?
  - Should we create allocations for:
    public purpose charges
    renewable resources
    energy efficiency
    combined heat and power and other self-generators (is there a de minimus capacity for self-generators/CHP?)
  - Should a standard account for early reductions? Would it matter?

F. Renewable Portfolio Standard Provision — Including the components of an RPS would have to address several issues.

  - Resource eligibility (perhaps including separate targets for resources or sub-resource technologies within each category)

- Vintage (only projects built after a specific year)
- Size of targets (absolute capacity or energy, percent of load, or percent of load growth)
- Timing of targets (deferred until a time when loads have grown or fixed targets for specific years)
- Compliance paths (whether to require bundled power purchases or whether to allow renewable energy certificates or "green tags")
- Price or cost caps (absolute or pegged to shifting market values)
- Covered entities (all utilities or inclusion of retail access suppliers)
- Geographic eligibility (in- and out-of-state plants or in-state only)
- Banking (carryover from over-compliance years to future years and true-up provisions)

G. GHG Allowance Tracking System — Define procedures for:

- Establishing and maintaining CO_2 allowance accounts.
- Procedures for allowance reporting and record of transfer by any owner of allowances.

H. Allowance Banking

- Should the carbon allocation standard system allow for the banking of allowances year to year?
- If so should there be any temporal (shelf life) or quantity (limit on total banked allowances) limitations on allowance banking?
- Should the use of future year allocations (allowance borrowing) be permitted?

I. Leakage — How would the standard address leakage issues related to the power that utilities purchase from out of state?

- How can one control leakage without interfering with interstate commerce?

J. Trading — An allocation system may allow utilities to minimize the total cost of meeting the emissions limit more easily though allowance trading. It might also include project offsets if they are allowed.

- How can a carbon allocation standard be designed to allow trading while still achieving verifiable reductions of greenhouse gas emissions?
  - Will only state-issued allocations be tradable?
  - Should trading be limited to trades among those entities that have to meet a GHG or CO_2 emission standard?
  - If outside trades were allowed, what would be the grounds for allowing trades from outside the allocation system?
  - Should – and could – such a system be designed to incorporate features compatible with a regional emissions trading mechanism between Oregon and its West Coast partners (Washington and California)?
  - Between the West Coast and Eastern states?

K. Project Offsets

- . Will project offsets be allowed under the standard?

- If allowed, what types of offsets: Emission Reductions? Sequestration? Avoided Emissions?
- If offsets are allowed, will they be limited to sectors not within the allocation system, e.g. if the system only affects the electricity sector, would offsets be limited to reductions in direct use of fossil fuels?
- Will offsets be evaluated as unique projects or by criteria for a limited set of project types?
- Will amount of offsets that are allowed to a single entity or system-wide be capped? If so, how will the cap be applied: percent of total allowances or percent of decline in allowances?
- Will offsets be allowed for other GHG or only CO_2? Which ones?
- Will offsets be allowed from outside the state? If yes, will they only be allowed from other states that have a comparable GHG limit?

L. Interactions with other GHG regulatory systems.

- Interactions with other CO_2 regulatory requirements, e.g. Oregon and Washington CO_2 siting standards for new energy facilities? Can verified, retired offsets be counted in calculating the emissions from a regulated generator?
- Interactions with Renewable Energy Credits under an RPS statute (Green Tags) if CO_2 allowances are allocated to renewable energy? One or the other or both?
- Interactions with renewable energy feed-in tariff or PRUPA qualifying facilities laws and rules?
- Interactions with PGE's and PacifiCorp's participation in the public purpose charge for energy efficiency and renewables? How can we credit the appropriate utilities and ratepayers for the contributions of non-utility participants such as the Energy Trust of Oregon?
- Interaction with Consumer Protection /Misrepresentation Electricity Marketing Requirements (if applicable) such as the "Environmental Marketing Guidelines for Electricity"[3]?
- Implications of ownership of carbon reductions for entities not covered by the allocation standard but served by utilities that are covered, e.g. who owns an emission reduction in the electricity sector if allocations go to utilities but reductions are achieved by individual businesses, agencies, organizations, and individuals.

M. Safety Valve:**–** Should a "safety valve" be designed into the system to create temporary breathing room to respond to critical competitiveness issues, energy market price spikes or other unanticipated and transient pressures? Would it be additional allowances or a pause in the declining rate of issuing allowances?

[3] National Association of Attorneys General. "Environmental Marketing Guidelines for Electricity," Environmental Marketing Subcommittee of the Energy Deregulation Working Group, December 1999.

N. Economic Development:

- How can such a system be designed to capture economic development benefits for Oregon?
- How can a system be designed to capture the economic gains of Oregon's investments in greenhouse gas mitigation, while avoiding loss of competitiveness in energy pricing between Oregon and its neighbor states or other competitors?

O. Federal Preemption:

- Could such a mechanism be fitted with a response that is an "off-ramp" in the event of meaningful federal action that could constitute preemption?
- What should be considered "meaningful" federal action?

P. Emissions Monitoring — Define procedures for monitoring of CO_2 emissions (or other GHGs if applicable).

Q. Record Keeping — Define record keeping requirements.

R. Reporting — Define reporting requirements and procedures and annual schedule.

S. Compliance Determination — Determine length of true-up period for allowances. Define requirements, procedures and schedule for compliance determination at each GHG budget source at the end of each true-up.

T. Compliance Certification — Define requirements for certification of compliance at each GHG budget source at the end of each true-up period.

U. Penalties — Define penalty provisions for utilities or suppliers that fail to meet requirements.

V. GHG Allowance Account Maintenance Fees — Define the administrative fees (if applicable) and how ongoing administration of the program will be conducted.

W. Program Audit Provisions — Define the program audit schedule and scope if applicable.