Cost Assumptions for Input-Output Study
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Overview

The net costs of meeting a load-based cap on electric emissions depend primarily on the stringency of the cap, the design feature of the regulations, the underlying load growth and the costs of resource alternatives. This paper lays out the base assumptions for modeling the employment and income effects of a load-based cap. This modeling work will be performed by Adam Rose. (for Adam's vita see: http://www.geog.psu.edu/pdf/Rose_Vita_April_2006.pdf

The Technical Working Group of the Carbon Allocation Task Force will be asked to respond to these assumptions and suggest alternative scenarios. Idaho Power emissions data are not available so these analyses do not include Idaho Power. Idaho Power's retail MWh sales are 1.5 percent of the Oregon utility total.

The proposed cost assumptions for the base-case analysis below are, with the exception of the biomass cogeneration, derived from the Northwest Power and Conservation Council's (NWPCC) *5th Power Plan.* Costs per MWh in the *5th Power Plan* are in levelized 2000 dollars using a real discount rate of 4 percent. These value are converted to 2004 dollars by adding 8.2 percent based on the U.S. Personal Consumption Expenditures chain-weighed deflator.

The analysis assumes the following design features, base-period loads and CO_2 emissions:

Distribution of Emission Allowances: 5 percent auctioned and 95 percent distributed for free based on base-period CO_2 emissions by the utility or load-serving entity;
Cost of purchasing the auctioned allowances. The purchase costs of allowances are included as a utility costs, but the revenues are assumed to used to reduce utility sales and CO_2 emissions;
The base period is 2004 for this base case. The placeholder design is for the years 2003-2005 will be the base period. Loads for 2004 are assumed to be 49.07 million MWh (5,600 average MW) with associated emissions of 22.4 million metric tons of CO_2 (see "rough-base-emissions-12-2-05.xls").

There are four compliance periods: 2009-2011, 2012-2014, 2015-2017 and 2018-2020, with the following percentage reductions from the base period emissions: zero, 2, 8 and 15, respectively. On an annual basis, the cap doesn't begin declining from the 2004 base until 2013; i.e. 2012 has the same cap as 2009-2011. The emission reduction for 2020 is 17 percent from 2004 and 10 percent from 1990.

The analysis assumes the following resources are available:

Energy Efficiency. The analysis assumes there are sufficient energy-efficiency measures to meet just under one percent load growth from 2004-to-2020 (930 aMW) with costs at or below the risk-adjusted value of wholesale market power. Utility-owned or

fixed price power purchases do not have the price volatility of spot wholesale power. Risk-adjusting wholesale prices provides a market-cost estimate that is equivalent a stable cost resource. This estimate of Oregon conservation potential is 32 percent of the estimate in the 2950 aMW of conservation included in the Northwest Power and Conservation Council's (NWPCC) *5th Power Plan* for 2005 to 2025. (http://www.nwcouncil.org/energy/powerplan/plan/(03)%20Conservation%20Resources.pdf Table 3-1: *Achievable and Cost-Effective Conservation Potential* on page 3-4) This percentage is close to Oregon's load share of the NW region. The cost for these measures is assumed to be $26 per MWh (see *5th Power Plan*, page C-3).

Cost-Effective Renewable Generation Additions. It is also assumed that Oregon has access to 800 aMW of new renewable resource generation at or below the risk-adjusted cost of wholesale power. This is renewable power that utilities acquire before acquiring new fossil-fuel power plants to meet load growth in the *5th Power Plan.* The *Plan* estimates of the amounts of wind available in Oregon, Washington and Idaho at two cost levels. At cost of $38 per MWh the *5th Power Plan* has 750 aMW potential wind generating projects. At a cost of $47 per MWh there is another 700 aMW.

This analysis assumed that by early action Oregon can acquire half of this regional potential for a total of 725 aMW. This would be available to Oregon if it acts in advance of neighboring states to acquire renewable resources.

The remaining 75 aMW of low-cost renewable generation is assumed to be new biomass co-generation at existing lumber and wood product factories in Oregon at a cost $47 per MW. Combined with load reductions through energy efficiency programs, these low-cost zero-CO_2 resources could meet an Oregon load growth of 1.7 percent per year for 2004-to-2020.

Above-Market-Cost Renewable Generation Additions. It is assumed that roughly 800 aMW of Oregon conservation and regional renewable generation are available at costs beyond other resource alternatives. These would be needed if Oregon's annual load growth (in aggregate) averages more than 1.7 percent for 2004-to-2020. They would be used as zero-CO_2 resources to reduce emissions below the base period level. There also might be a need for above-market-cost resources to meet the 1.7 percent load growth if the actual performance of the cost-effective energy efficiency programs or renewables generation acquisitions does not meet expectations. On the other hand, if load growth is less than 1.7 percent and resource performance does meet expectations, cost-effective conservation and renewable resources could be used to reduce CO_2 emissions below the base level. In this base-case scenario, all of the load growth is met with cost-effective conservation and renewables and all reductions from the base level of emissions are met with above-market-costs conservation and renewables.

In this scenario acquisitions of these more expensive resources are assumed to be used to reduce emissions below the base period level beginning in the 2012-to-2014 compliance

period. The spreadsheet http://oregon.gov/ENERGY/GBLWRM/docs/Renew-displ-fossil-gen.xls and the memos http://oregon.gov/ENERGY/GBLWRM/docs/utility-by-utility-cost-est.pdf and http://oregon.gov/ENERGY/GBLWRM/docs/Cost-est-by-utility-memo.pdf show the "costs" to utilities based on the range of above-market costs for new renewables ($ per MWh) and the purchase price of allowances ($ per metric ton of CO_2). These costs include the purchase of allowances at auction. The costs in the previous memos are slightly different from this memo, because this memo has the declines in the cap for 2012-to-2014 and 2018-to-2020 as 2 and 15 percent, respectively. The previous reduction values were 1 and 17 percent reductions, respectively.

The revenues from the auctioning five percent of allowances that are auctioned would be used to reduce the need for public purpose charges or other utility sources of funds for conservation and renewable programs At allowance auction prices from $5 to $35 per metric ton of CO_2, the auction revenues would range from 0.2 to 1.4 percent of total Oregon retail revenues. Even with these revenues, retail charges (a.k.a. public purpose charges) for energy efficiency might need to be raised from the current 2 percent of retail revenues for PacifiCorp and Portland General Electric (PGE). The Eugene Water and Electric Board (EWEB) current spends about 5 percent of its retail revenues to reduce its loads about one percent each year. The Energy Trust of Oregon estimates that about 4 percent of retail revenues for energy efficiency programs are needed to capture 85 percent of the technically-available cost-effective conservation. Part of this money would be supplied by auction revenues. The higher the allowance price the higher the contribution from auction revenues.

Using the results of revised Renew-displ-fossil-gen.xls

PGE 2018-2020
(Real 2004 Dollars)

Above Market Cost @ $/MWh:	$ 5.00	$ 10.00	$ 15.00	$ 20.00
Extra Cost to PGE (million $ per year)	$ 18.67	$ 37.34	$ 56.01	$ 74.68
% of 2004 Retail Revenue	1.5%	2.9%	4.4%	5.9%

2004 Retail Revenue ($M)	1,271

Reduction	1.77	Million Metric Tons

PGE Buys Allowances @ $/MT-CO2:	$ 5.00	$ 10.00	$ 15.00	$ 20.00	$ 25.00	$ 30.00	$ 35.00
Cost to PGE (M$/yr.)	$ 8.83	$ 17.67	$ 26.50	$ 35.33	$ 44.17	$ 53.00	$ 61.83
% of 2004 Retail Revenue	0.7%	1.4%	2.1%	2.8%	3.5%	4.2%	4.9%

The cost to PGE will be the lesser of the two percentages, depending on the relationship between the above market costs of conservation and renewables and the allowance auction price. In actual practice PGE would acquire above-market renewables and conservation when this costs less than buying allowances. The costs above assume that all of the 1.77 million metric ton of PGE reductions or allowance purchases would, by itself, bring the utility into regulatory compliance.

PACIFICORP 2018-2020
(Real 2004 Dollars)

Above Market Cost @ $/MWh:	$ 5.00	$ 10.00	$ 15.00	$ 20.00	$ 25.00	$ 30.00
Extra Cost to PAC (M$ per year)	$ 13.89	$ 27.78	$ 41.67	$ 55.56	$ 69.44	$ 83.33
% of 2004 Retail Revenue	1.9%	3.9%	5.8%	7.8%	9.7%	11.6%

2004 Retail Revenue ($M)	716.5	Reduction	2.44	Million Metric Tons

PAC Buys Allowances @ $/MT-CO2:	$ 5.00	$ 10.00	$ 15.00	$ 20.00	$ 25.00	$ 30.00	$ 35.00
Cost to OR-PAC (M$/yr.)	$ 12.18	$ 24.35	$ 36.53	$ 48.70	$ 60.88	$ 73.05	$ 85.23
% of 2004 Retail Revenue	1.7%	3.4%	5.1%	6.8%	8.5%	10.2%	11.9%

There are similar tables for PGE and PacifiCorp for 2012-to-2014 but with values roughly one-third the level costs in for 2018-to-2020 shown above. See: http://oregon.gov/ENERGY/GBLWRM/docs/Renew-displ-fossil-gen.xls.

The reductions for 2012-to-2014 are one-third of 2018-to-2020 because the reductions modeled are not just the 2 and 15 percent reductions in the overall CO_2 cap. The CO_2 reductions also include the 5 percent of allowances that is auctioned. The auction revenues are then used to reduce public purpose charges. The amount of reduction would depend on the auction price.

Consumer-owned utilities. It is presumed that consumer-owned utilities would acquire cost-effective energy efficiency and renewable generation to cover their load growth. They would buy auctioned allowances to cover their mandated reductions. For the COU's this would be 0.04 and 0.11 million metric tons of allowances per year, respectively in 2012-to-2014 and in 2018-to-2020. Total auctioned allowances would be 1.10 and 0.95 million metric tons per year, for the periods 2012-to-2014 and 2018-2020, respectively.

Base Case Scenario

There is uncertainty regarding the factors that affect the cost of complying with a load-based CO_2 cap. For a specific regulatory structure, the most significant factors are load growth and the costs of resource alternatives. For the base case an assumption of an annual load growth of 1.7 percent from 2004 to 2020 seems reasonable. Portland General Electric's forecasted growth rate from 2005 to 2025 is 2.1 percent (PGE handout 5/9/06 IRP meeting). Its historical growth rate from 1985 to 2005 was 1.8 percent (*ibid).* PacifiCorp forecasts a growth rate for its Oregon sales of 1.2 percent (4/20/06 IRP Handout). Its historical growth rate of sales from 1985 to 2004 was 1.0 percent (OPUC *Oregon Utility Statistics*, same years). The total Oregon utility sales growth rate from 1985 to 2004 was 1.3 percent. *The Plan* forecasts that NW utility loads will grow from about 17,603 aMW in 2004 (assumed by *The Plan* to equal to 2000 loads) to 24,464 aMW in 2025, for an average annual growth rate of 1.6 percent. *The Plan* low and high forecasts for this same period are 0.05 and 3.2 percent, respectively. This indicates how uncertain load growth forecasts are.

The 1.7 percent load growth and the resource assumptions (above) provide results consistent with the analysis in the *5th Power Plan. The Plan forecasts* that load growth can be met with little or no growth in CO_2 emissions. For reductions in emissions starting in 2013 an average cost of emissions reductions of $20 per metric ton of CO_2 seems reasonable (2004 $). Some conservation and renewable resources should cost only slightly more than wholesale power. Even if the most expensive measures cost as much as the alternative compliance payment of $40 per tonne, most of the resources should cost less, resulting in an average well below $40.

For PGE the average emission reduction cost $20 per tonne translates to an average above-market cost of $9 per MWh. For PacifiCorp the average cost $20 per tonne of

allowances translates to an ~~average~~ maximum above-market cost of $17 per MWh. This difference occurs because PGE's above-market resources reduce its emissions at the net system mix CO_2 rate of roughly 1,000 pounds per MWh but PacifiCorp's rate of reductions is based on its average system mix rate of roughly 1,900 pounds per MWh.