Cost and Design Considerations for Reducing Carbon Dioxide from Oregon's Power Sector: A Report to the Carbon Allocation Task Force

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EXECUTIVE SUMMARY

This report to the Oregon Governor's Carbon Allocation Task Force outlines key cost and design considerations for its deliberations on a load-based cap and trade program for the power sector. Recent studies show there are significant low-cost efficiency investments available for reducing CO_2 emissions. However, should Oregon be able to deploy all its energy efficiency that costs less than wholesale power, electric sector emissions of carbon dioxide (CO_2) in 2020 under medium load growth will still be approximately 28 million metric tons, or about 36 percent higher than in 1990. The addition of a renewable portfolio standard (RPS) equal to 20 percent of sales in 2020 would halt, but not reverse, the rise in emissions. Therefore, further reductions from additional renewable energy and energy efficiency investments are needed

The modeling results indicate that a cap reducing CO_2 emissions to an average of 19.1 million metric tons during the period from 2018 through 2020 can most likely be done at a net economic benefit to the state. These benefits accrue largely because of the cost savings associated with below-market energy efficiency investments. The modeling shows that the CO_2 cap alone will provide statewide benefits of over $100 million a year through 2015. Under the low and medium load growth scenarios the net present value of *benefits* from the CO_2 reductions from combination of the CO_2 cap and the RPS are estimated at $520 and $250 million respectively. The present value of *costs* to ratepayers under a high load growth scenario could approach $415 million.

This report also addresses the important relationship between the RPS and the CO_2 cap. The RPS and the CO_2 cap should be viewed as complimenting each other due to uncertainty about future market conditions. If gas prices decline considerably then the CO_2 cap will probably result in more fuel switching from coal to gas rather than deploying renewables. Without an RPS, renewables deployment might be reduced by 40 percent in this scenario and would result in the state's renewables goals not being met. Another way to think about the relationship between the RPS and the CO_2 cap are their relative program goals. A renewable portfolio standard is typically considered to be an example of an *energy policy*: improve energy security, promote rural economic development, and diversify energy supply away from fossil fuel price variability and hydro availability. In contrast, a CO_2 cap is primarily an *environmental policy* focused on reducing the emission of climate changing gases. To reduce CO_2 by reducing demand or substituting gas for coal generation would not capture the energy policy benefits of renewables. Both the RPS and CO_2 cap are needed to meet all Oregon's policy goals.

The data presented here indicates that the load based CO_2 cap is a relatively low risk program. The climate policy brings significant bill savings to the state from increased energy efficiency. Aggressive early action from renewables and energy efficiency can facilitate much cheaper compliance later in the program as the cap declines. These early actions will help to moderate the largest source of risk to the load based CO_2 cap, that of fossil-fuel based load growth.

"It's tough to make predictions, especially about the future."**--** Niels Bohr

INTRODUCTION

The 2004 Governor's Advisory Group on Global Warming set an ambitious target for Oregon to reduce its contribution to human induced climate change. The Group established the following goals: Oregon's total greenhouse gas emissions will be 10 percent below 1990 by 2020, and will meet a long term climate stabilization target of a 75 percent reduction by 2050. In 2005, Governor Kulongoski adopted the goals for the state and appointed the Carbon Allocation Task Force to examine the feasibility of, and develop a design for, a load-based carbon allowance standard for Oregon. Over the last 15 months, the Task Force has proceeded to translate these goals into a workable proposal for the 2007 legislature. Table 1 shows the emission target for the proposed CO_2 cap.

Several policy options are available to Oregon policymakers to reduce carbon dioxide (CO_2) from the power sector. The first is to increase the amount of energy efficiency investments that cost less than wholesale power. Oregon has a history of successfully deploying energy efficiency to reduce the need for new power plants or wholesale power purchases.

Another policy option that the 2004 Advisory Group recommended to be evaluated is requiring that a certain percent of the electricity sold in the state come from renewable resources.[1] This option is being developed by the Governor's Renewable Energy Working Group. However, with moderate levels of growth in electricity demand these two policies would not meet the 2020 CO_2 target. The 2004 Advisory Group recommended examination of a load-based carbon dioxide cap-and-trade system as an additional mechanism.

Under the load-based cap-and-trade, load serving entities (LSEs) such as consumer owned utilities (COUs), investor owned utilities (IOUs), independent retail electricity service suppliers (ESSs), and self-generators above a certain size would receive or purchase at auction allowances to emit carbon dioxide. The initial distribution would be based on their historical emissions. One of these allowances would be surrendered for each ton of CO_2 emitted and allowances could be traded among LSEs. The total amount of allowances declines over time at a pre-specified rate until the 2020 target is met.

The cap's architecture includes features to limit the cost of the program to utilities. Utilities can purchase offsets that are emissions reductions projects implemented away from the utility system but that can count towards the utility's cap. Under the median proposal, if the price of allowances exceeds $40, then utilities can comply with the cap through an alternative compliance payment (ACP), which lets them purchase additional

[1] The Oregon Strategy for Greenhouse Gas Reductions can be found at: http://oregon.gov/ENERGY/GBLWRM/Strategy.shtml

allowances rather than further reduce emissions on the system. There would be no limit on the number of allowances the state would sell at $40.

Table 1: The Load-Based CO_2 Cap Emissions Targets

	Phase I	Phase II	Phase III	Phase IV
	2009-2011	2012-2014	2015-2017	2018-2020
CO2 Cap (Million Metric Tons) 3 Year Average	22.4	21.9	20.5	19.1
% CO2 Reduction Requirement Below Base Period (Approx. 23.3 MT)	3.76%	5.91%	11.93%	17.94%

A load-based system is distinguished from the trading system in Europe or the one proposed for the Northeast U.S. in that generation sources that are not physically located within the state but that serve Oregon's load would be covered. Emissions from some coal plants in Montana, Wyoming, Utah and Idaho, if they served Oregon loads, would be included under an Oregon load-based cap. Emissions from electricity lost during transmission would also fall under the cap. Plants in Oregon that serve loads in other states would not be covered, but new power plants in Oregon already face a CO_2 emissions standard where emissions must be below commercially available technology levels. Facilities developers must provide offsets or financial payments that fund offsets for emissions beyond the standard

The strength of the load-based approach is that it deals up-front with leakage issues facing a smokestack-based system like the Regional Greenhouse Gas Initiative (RGGI) for the Northeast U.S. RGGI parties have formed the Imports and Emissions Leakage Working Group in order to address the problem. Both the smokestack and load-based cap can address emissions for imported power, but it is a fundamental part of a load-based cap rather than an issue to be addressed later.

CHALLENGES FOR A LOAD-BASED SYSTEM

Although a load-based cap is an intuitively appealing concept and deals directly with leakage issues, it has its own challenges. A concern with load-based caps is contract shuffling. In the absence of a West-wide carbon accounting system for power plants, regulated actors have an incentive to sell power from plants with high levels of emissions into the wholesale market while concurrently purchasing cleaner power from the market to meet load.

Another challenge to designing a load-based system is choosing a methodology for the rate at which LSEs are credited for projects that reduce CO_2 emissions. One way for an LSE to meet the cap is by purchasing or building new renewable generation projects and reducing its use of its existing mix of fossil-fueled generation. The Task Force is proposing that utilities be credited at their average CO_2 emissions intensity, which is equal to annual CO_2 emissions divided by annual MWh generation for Oregon demand. However, if a utility does not have enough of its own generating resources, or power purchases from specific plants to cover its load, then it is considered resource deficient.

If a utility is resource deficit, increased renewable generation or reduced demand due to the load-based CO_2 cap is credited at the CO_2 rate for unclaimed power in the U.S. portion of the Northwest Power Pool.[2]

Oregon's LSEs represent a diverse group in terms of their generating mix and average emissions intensity. PacifiCorp's average emissions rate is about 1,800 lbs of CO_2 per MWh due to its coal resources. In contrast, most COU's have an emission rate of just over 100 lbs per MWh because the vast majority of their power comes from hydro and nuclear generation with only about 10 percent from wholesale market purchases. COUs have a unique situation with contracts from the Bonneville Power Administration. Crafting a cap-and-trade proposal that treats utilities equitably in such different situations was a key challenge for the 15-month process.

Determining CO_2 Costs by Utility

Given the CO_2 emissions methodology, the cost of emissions reduction projects can be calculated for LSEs. The modeling for this report uses the Oregon Clean Energy Planning Model©, a spreadsheet model developed to help the Task Force understand the impacts of the cap on Oregon's power sector. The model simulates how LSE's would comply with the CO_2 restrictions. Using a "bottom-up" approach, the model calculates the costs of CO_2 reduction measures for each major type of LSE based on the cost of projects available in MWh and the CO_2 credit per project.

For example, if wind costs $10 more per MWh than a standard new fossil fueled plant, and a utility is credited at 0.5 tons/MWh, then the cost to the utility for wind is $20 per ton of CO_2. The model utilizes six different cost curves, one for each utility, to develop its cost estimates.[3] For each curve there is a separate cost ($/ton of CO_2) for each year. The modeling assumptions and structure are described in more detail in the Appendix. The effects of these crediting differentials are substantial. Consider the models estimated costs per ton of CO_2 for the first tranche of biomass: $5.35, $9.49, $110.27, and $8.17 for Pacific, PGE, the COUs, and Idaho Power respectively.[4]

Not only does each utility have a different cost curve for CO_2 reductions, their absolute reduction targets are quite different. The size of emissions reductions required to meet the cap varies where COUs would need only a few tons of reductions while some IOUs would require hundreds of thousand of tons. Each utility has to reach up the supply curve differently to meet its CO_2 target. The mitigation measures in the model reflect limited supplies of renewables and the utilities that need to deploy greater quantities pay more for the last unit they purchase.

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[2] Several knowledgeable stakeholders recommended crediting reductions at the marginal dispatch resource rate—typically peaking gas at a rate of about .5 metric tons per MWh. While this approach is probably more reflective of how the grid actually operates, it was not selected because of the disparity between LSE intensities and the marginal resource. For example, consumer owned utilities emit only about .05 metric tons of CO_2 per MWh so crediting their reductions at the marginal rate could dilute the cap level.

[3] COUs are treated as one utility for simplicity of analysis.

[4] Each renewable energy technology has at least one cost tranche or group to represent the upward sloping supply curve. Wind, biomass, and energy crops have a low cost tranche and a high cost tranche.

Given this variance in marginal CO_2 reductions costs, another goal for the modeling team was to develop estimates of the market price for traded or auctioned allowances. The technical work group of the Task Force decided that a simple average of PacifiCorp's and PGE's marginal costs is adequate to represent the allowance price. The two IOUs supply almost 70 percent of Oregon's electricity and nearly 95 percent of CO_2 emissions from the electricity sector.

Rate Impacts versus Bill Impacts

The model estimates the impacts of the program on customers' rates and bills for the different LSE's. Unless otherwise noted, the modeling runs include the assumption of the existing charge of 1.7 percent of retail revenues applied statewide to fund energy-efficiency programs. These programs save energy at a cost substantially below the market price of wholesale electricity. The "climate policy" scenario adds an additional energy-efficiency charge of 1.8 percent of retail revenue for below-market energy efficiency measures, as well as other costs associated with meeting the emission reductions targets. Therefore, the climate policy more than doubles existing energy efficiency funding to capture energy efficiency that is cost-effective before considering climate change. It is efficiency that is currently available, but not captured due to lack of program funds and the 1.8% funding level is adequate to capture the available conservation resource. The model also assumes the Renewable Energy Working Group target of meeting 25 percent of electricity sales by 2025 from renewable generation.

The model outputs for each run include an estimate of rate impacts and bill impacts from the climate policy scenario. Rate impacts include all the costs of the program and none of the benefits of reduced power consumption from energy efficiency programs. Rate impacts include the following categories of costs:

- The costs of the additional below-market energy efficiency investments
- Offsets purchases
- The costs of the grid connected emissions reductions from renewables and above-market energy efficiency.
- Further allowance purchases needed to meet the program requirement.[5]
    - This cost also includes alternative compliance payments when the price of allowances exceeds the $40 ACP. The ACP is discussed in more detail below.

The rate impact estimate is an appropriate measure only when a customer is not expecting to receive any program investments in energy efficiency. Typically, large industrial and commercial customers show the largest price concern about rate impacts, but these end-users have concentrated energy efficiency potentials as well as the resources and

[5] Some allowances would be purchased at an auction conducted semi-annually. The revenues from the annual actions are assumed to go to energy efficiency and are thus already incorporated into the model's cost structure. Other allowances might be traded between LSEs. Sellers would be those utilities that achieved enough reductions so that their emissions were less than the amount of allowances they received for free. This version of the model doesn't estimate trading between LSEs.

technical expertise to capture efficiency investments. Energy efficiency programs have greater challenges weatherizing homes owned by low-income households and rental units. These residential customers may also be especially impacted by rate increases.

Bill impact is the net cost to LSE customers of energy efficiency. Thus, it includes all the costs from rate impacts less the benefits from efficiency.[6] If energy efficiency program benefits were distributed to all existing and new customers equally, then the rate impact measure would be unnecessary. Only the bill impact measure would matter. As this is not always the case, both measures are provided. The model also reports the rate impact to an average residential electric customer.

The modeling also measured the rate impact of the climate policy energy efficiency including the effect of relatively fixed costs of transmission and distribution (T&D) costs. Tariff rates in the model were divided into a) generation costs, b) fixed non-generation, non-conservation costs, c) variable non-generation, non-conservation costs, d) program costs from energy efficiency, offsets, allowances, etc. These cost bins show how demand reduction can impact rates by comparing the variable cost component for different scenarios.[7]

The impact of spreading fixed costs over fewer MWhs of sales in the climate policy cases can be estimated. There are few local studies on estimating fixed and variable costs, and it is more of an art form than a science. Given this, the cost per MWh from fixed costs in the no policy case is about $14.30 versus $13.40 in the climate policy and RPS case. A residential ratepayer who uses one MWh a month might see a $.90 increase in their monthly bill by 2020 from the impacts of spreading fixed costs associated with energy efficiency.

The potential increase in bills from fixed costs is offset by less spending on new transmission, distribution, and administrative costs from energy efficiency. Other studies have shown that aggressive energy efficiency has substantial economic benefits.[8] RGGI modeled the hourly dispatch and capacity benefits of different energy efficiency technologies. The modeling showed between $100 to $300 a year customer cost savings

[6] The Task Force technical working group recommended utilizing a benefit cost ratio to estimate the system benefits from energy efficiency. This research uses the cost ratio from the Northwest Power and Conservation Council's Fifth Power Plan of 2.5:1. They define it as "'benefit-to-cost' (B/C) ratios are derived by dividing the present value benefits of each measure's energy, capacity, transmission and distribution and non-energy cost savings by the incremental present value cost (including program administration) of installing the measure." Footnote 7, p. 3-4.

[7] The non generation, variable cost portion of the tariff considered here is applicable to decadal level investments in mostly distribution assets such as substations and transformers that are associated with new load. Efficiency investments can allow for new loads without these variable costs to the extent that the efficiency frees up existing capacity for the "new" end users. The modeling results presented here use a 25% value for the variable, non-generation cost parameter. Fixed, non-generation costs are also 25% in the model except for PGE which is 20%. The balances of costs are generation costs.

[8] Skip Laitner (2006). *An Annotated Review of 30 Studies Describing the Macroeconomic Impacts of State-Level Scenarios Which Promote Energy Efficiency and Renewable Energy Technology Investments.*

from aggressive energy efficiency programs.[9] Additional modeling efforts are required to model the effects of the CO_2 program on total economic impacts to Oregon. The technical work group has not had the resources to evaluate how additional renewable energy projects and above market energy efficiency deployed under the climate policy will impact state economic development. However, the impacts of reduced net costs to customers are always positive. The modeling does include some preliminary data about the effects of changes in electricity expenditures from the CO_2 cap on Gross State Product. These results are presented in the next section.

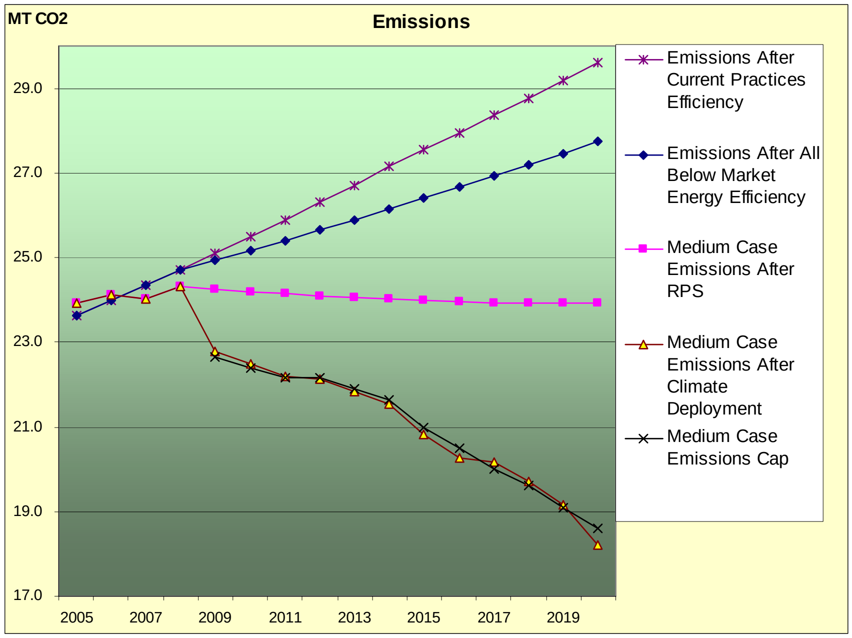
MODELING GOALS AND RESULTS

The Oregon Clean Energy Planning Model© is a customized Excel model for the Oregon Carbon Allocation Task Force. The model is intended to be used by stakeholders to better understand the most important policy variables in a carbon reduction program out to 2020. It is a modified capacity expansion model of annual load resource balances. The outputs from the model are intended to supplement traditional Integrated Resource Planning exercises that can give more detailed cost estimates.

The modeling process was as transparent as possible. Inputs to the model were reviewed by the technical work group of the CATF that was open to members of the public. The goal was to inform the policy process, not only at the Task Force level, but also to provide a modeling tool that can assist the public policy process going forward. Chart 1 shows the model's estimates for emissions under four different policy conditions for the medium load growth scenario. The scenario

[9] *RGGI Region Projected Household Bill Impacts*. Available at http://www.rggi.org/documents.htm Also see Prindle et al (2006). *Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative.*

Chart 1: Emissions Paths



in the top line of the chart represents current practices energy efficiency programs but no new renewable projects. Under this case, emissions are forecasted to grow at a linear rate through 2020 reaching almost 30 MT, a 46 percent increase from 1990 estimated emissions. The second line includes the energy efficiency under the climate policy. Notice that even adding another 1.8 percent systems benefit charge statewide only slightly reduces the slope of emissions growth and does not reduce absolute emissions.

The RPS line includes the above energy efficiency and also assumes the addition of renewables equivalent to 1 percent of load per year from 2009 through 2020 culminating in over 15 percent of load (close to 20 percent of sales). With a renewable portfolio standard, emissions can be held roughly steady throughout the program life from the time the RPS is assumed to go into effect. Finally, the CO_2 cap is represented by the downward sloping line with X's as markers.[10] The model's forecast of emissions is represented by the line with triangles. The model doesn't converge perfectly with the cap due to technical reasons, but reasonably tracks the cap with the exception of 2020 when it slightly over complies.

[10] Instead of a step function representing the lowered cap in each phase of the program, the CO2 cap in the model is a downward sloping line. This is done to help the model converge to an equilibrium solution. The continuous line assumes that each utility under complies by a certain amount in the first year of each phase, hits the target in the middle year, and over complies by the same amount in the last year. The net effect is compliance with the target in each phase.

Load Growth Scenarios

Load growth is one of the most uncertain modeling parameters, and one that has the largest impacts on program cost estimates. The technical working group decided to present a range of load growths that will encompass a wide range of load scenarios. The low-load scenario assumes an annual growth of 0.7 percent before implementation of energy efficiency programs. The corresponding moderate and high scenarios assume annual rates of 1.7 percent, and 2.7 percent respectively. The Appendix contains data on historical load growth figures as well as the range of forecasts from the Northwest Power and Conservation Council's Fifth Power Plan.

Table 2: Net Present Value Estimates for 2009-2020 Cash Flows

	0.7% Load Growth	1.7% Load Growth	2.7% Load Growth
Net Present Value of Benefits (costs) of Climate Policy Beyond RPS	$790	$638	$39
Net Present Value of Benefits (costs) of Climate Policy and RPS	$518	$255	($414)

Table 2 shows the costs to the state are estimated using net present value (NPV), which is the value at the present of a stream of future cash flows. The figures represent the annual cash flows from the program (customer cost impacts) out to 2020, but are discounted back to 2005 dollars using the seven percent interest rate parameter in the model. The net present value of the climate policy (including the RPS) to Oregon ranges from a $518 million benefit to a $414 million cost under the various load growth scenarios. Benefits come from the program because the societal returns from energy efficiency exceed its cost over the life of the program. In the medium load growth case, these cash flows are over $100 million a year through 2015 (not shown). A more detailed examination of energy efficiency is in the following section.

Table 3: Average of Phase IV (2018-2020) Annual Outputs

	0.7% Load Growth	1.7% Load Growth	2.7% Load Growth
Forecasted Allowance Price	$ 3.75	$ 21.14	$ 40.00
Rate Impact of Climate Policy Only	6.2%	4.4%	7.5%
Rate Impact of Climate Policy and RPS	6.3%	6.5%	10.4%
Monthly Rate Impact to Residential Ratepayer for Climate Policy and RPS (1000 kWh/month)	$ 0.70	$ 1.66	$ 2.95

While the net present value looks at the program over its entirety, it's also worth examining the costs of the program in the last phase (Phase IV, 2018-2020) when costs are likely to be highest. Table 3 shows the rate impacts of the climate policy including all of the program costs such as renewables, energy efficiency charges, offsets, and allowances and ACPs. The rate impact results from the model for the 0.7 percent load growth are counterintuitive and are inflated mostly from the costs of new renewables, and also from conservation costs of the programs that are spread over fewer MWh. To understand the cost of the climate policy in the 0.7% case, a better indicator is the allowance price or the monthly residential bill impact. Given this inconsistency between the 0.7 percent scenario with the other scenarios, rate impacts for the climate policy alone are likely to range from less than 4 percent to over 7 percent of rates,

Table 4: Average Annual Rate Impact of Climate Policy and RPS

	Phase I	Phase II	Phase III	Phase IV
1.7% Load Growth	2009-2011	2012-2014	2015-2017	2018-2020
Pacific	4.24%	6.39%	8.38%	12.42%
PGE	0.27%	1.71%	2.73%	3.81%
COUs	0.30%	1.83%	2.90%	3.96%
ID Power	-0.01%	2.01%	5.01%	8.51%
ESS-PAC	0.02%	1.42%	2.36%	2.92%
ESS-PGE	0.64%	2.17%	4.02%	5.60%
Load Weighted Average	1.47%	3.17%	4.53%	6.53%

The rate impacts are likely to vary considerably by utility and by time. Recall that rate impact measures assume that the benefits from energy efficiency don't flow back to customers in the system. Table 4 shows that in the medium load growth scenario, the rate impacts to customers are modest throughout the program and are likely to be negligible for the next 5 years in most of the state.

Utility customers across the state are likely to feel very different impacts due to the climate policy and RPS. Rate impacts to PacifiCorp are estimated to be the highest due to the carbon intensity of its generation portfolio. However, rate impacts are not directly comparable between utilities because of the differences in tariff levels. Part of the reason that the rate impact for PacifiCorp is higher is due to its low tariff rates. COUs also have low cost tariffs due of low cost BPA power.

The cost estimates from the Oregon Clean Energy Planning Model© are comparable with other recent modeling efforts for the power sector. RGGI modeling forecasts allowance prices of about $11 in 2021. Compared to Oregon, this is a less stringent CO_2 emissions cap that holds emissions relatively unchanged over the life of the program and hence CO_2 costs are lessened. Due to the benefits of energy efficiency, the benefits of the program and the federal program to participating households could be $120 a year, or $12 a year if all bill savings are distributed equally across all households.[11] Using NEMS, Bailie et al (2004) modeled West-wide impacts of a $20 a ton CO_2 price, aggressive energy efficiency and combined heat and power programs, and a similar RPS to the one

[11] RGGI data can be found at http://www.rggi.org/documents.htm. The efficiency data is rggi_household_bill_impacts_12_12_05. The allowance estimates are ipm_modeling_results_9_21_05_01.

considered in Oregon.[12] Their results indicate that these policies could reduce power sector emissions by about 50 percent from 2004 levels by 2020. This is a larger reduction than the Oregon cap but with similar costs.

One of the reasons that NEMS and other economy-wide models might show greater cost savings than the Oregon Clean Energy Planning Model© is because these models can capture price reductions in natural gas and thermal power prices due to increased energy efficiency and renewables. Renewable generation and energy efficiency takes pressure off the natural gas market. Elliot et al (2003) estimate a 3.4 to 1 benefit cost ratio for renewables and energy efficiency. Three quarters of these benefits flow to residential, commercial and industrial gas customers.[13] Wiser et al (2005) find that "each 1% reduction in national gas demand is likely to lead to a long-term (effectively permanent) average reduction in wellhead gas prices of 0.8% to 2%".[14] Their research indicates that regional price reductions are potentially larger than national reductions when the region is supply constrained due to gas transportation limitations.

These types of benefits from the Oregon CO_2 climate policy and RPS are not captured in this report because only the power sector was modeled here. However, we do have estimates of partial economic benefits. ODOE estimated the economic impacts of the costs of the program to the state based on the estimated relationship between electricity prices and economic output. The data on the effects of different resource mixes such as coal versus wind on state economic activity are not included in these results. Table 5 represents a partial estimated value to Oregon from the CO_2 cap based.[15] A range of numbers is presented for the medium load growth case that represents the high and low estimates of the impacts of price changes on economic output.[16] In the best case, the net present value of the program is approximately a $350 million dollar boost to state output. In the worst case the program would decrease state output by $200 million.

[12] Bailie, et al. (2004). *Turning the Corner on Global Warming Emissions: An Analysis of Ten Strategies for California, Oregon, and Washington*. Tellus Institute. P. 20.
[13] Elliot, R.N. et al. (2003). *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*. ACEEE Report Number E032. December.
[14] Wiser, R., Bollinger, M. St. Clair, M. (2005). *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency.* P. 9. LBNL-56756. January.
[15] Data based on ODOE analysis.
[16] From Wie and Rose (2006). *Survey of the Literature on the Energy Price Elasticity of Economic Output*.

Table 5: Partial Economic Impacts of Climate Policy

	0.70% Load Growth	1.70% Load Growth	2.70% Load Growth
Average Annual Net Benefit to Customers of Climate Policy in 2018-2020 Period (million $)	$ 130	$ 83	$ (73)
Gross State Product Impact: Low Survey # (million $)	$ 71	$ 45	$ (40)
Gross State Product Impact: High Survey # (million $)	$ 353	$ 225	$ (198)

Effects of Energy Efficiency Deployment on Program Outcomes

Energy efficiency is the cheapest source of clean energy and is therefore the foundation of any program dedicated to reducing CO_2 emissions from the power sector. The metric used in this report estimates the benefits of energy efficiency at 2.5 times the cost.[17] Two scenarios are presented here to understand the variability that energy efficiency investments can have on program costs.

The *low energy efficiency* case assumes that the additional 1.8 percent climate policy systems benefit charge under the medium case does not get implemented and efficiency investments are limited to current IOU levels of 1.7 percent of revenues (the no-policy case). A similar outcome would be if efficiency investments in some service territories are not implemented according to the medium case assumptions listed in the appendix. The low energy efficiency scenario shows the following results:

- Because of the foregone savings in the early phases, the total climate policy program (w/RPS) net present value (NPV) is reduced from a $300M benefit to a $750 million economic cost. The difference between the low energy efficiency case and the medium case indicates that the proposed Climate Policy saves Oregon's consumers over a billion dollars worth of expenditures on electricity versus the current energy efficiency funding level.
- Allowance costs in the last phase of the program increase from an estimated $21 to $36.
- Due to increased loads under this scenario the total amount of renewables that are required under the climate policy and RPS reaches 17.3 million MWh in 2020. This compares to 16.3 million MWh in the medium climate policy case.

Also consider a *high energy efficiency* case where energy efficiency resources are greater than the 900 aMW estimated in the medium case. Note that the 900 aMW cap in the medium case on below market energy efficiency doesn't include any combined heat and power deployment, electricity T & D upgrades, nor does it necessarily include the "low hanging fruit growing back" which was the subject of considerable discussion in the full Task Force meetings.

[17] From the NorthWest Power and Conservation Council's 5th Power Plan.

In this case, the climate policy efficiency deployment is increased by half to 2.7 percent of sales and total deployment reaches 1125 aMW by 2020. This is a 1.5X efficiency scenario compared to the climate policy scenario. The high energy efficiency scenario includes the following outputs:

- The total NPV of the benefits of the program (including the RPS) increase to $366M. The NPV of the climate policy alone is over $720M.
- Estimated allowance prices in the last phase of the program drop by over a third to $13.50.
- The amount of renewables deployed in 2020 under the climate policy and RPS is only 14.4 million MWh, significantly reducing the cost of the compliance as the absolute target is lower due to the additional efficiency measures.

The contrast between the high and low energy efficiency cases is very stark. The take-away here is that deploying every MWh of energy efficiency is the best way to ensure state economic development goals are met and is the path to the lowest cost CO_2 cap and RPS.

Substitutability between the Renewable Portfolio Standard and the CO_2 Cap

A common misconception is that an RPS and a CO_2 are substitutes for each other. The argument here is that the RPS is going to deploy sufficient quantities of renewables to meet the CO_2 cap, so the CO_2 cap becomes redundant. While this argument certainly seems like common sense, it assumes a continuation of future market and policy conditions. However, CO_2 mitigation can come from a variety of sources including fuel switching and sequestration. If gas prices decrease substantially or carbon sequestration from coal generation becomes a preferred source of CO_2 mitigation due to public subsidies, then the market will deploy the cheaper measures, which will displace renewables from the climate policy.

Forecasting natural gas costs is at least as difficult as forecasting load growth. We expect reality to differ from point estimates of future prices, but several prominent published forecasts have recently underestimated natural gas price increases.[18] Consider that if this modeling for a CO_2 cap had been done a decade ago, the concept of $6/MBTU gas would have been declared ridiculous. Because the regulatory program is designed to reduce emissions out to 2050 the interactions between the two programs need to be carefully considered.

To show the effects of changing market conditions on program effectiveness, consider a *low gas price scenario* without an RPS requirements after 2012. "Turning off" the RPS

[18] See Bollinger and Wiser. (2005). *Comparison of AEO 2006 Natural Gas Price Forecast to NYMEX Futures Prices* and Wong-Parodi et al. (2005). *Natural Gas Prices Forecast Comparison - AEO vs. Natural Gas Markets*. Furthermore, it appears likely that the relationship between commodities is changing as institutional investors diversify into the asset class. See the October 12th, 2006 version of *The Economist*. Roll over: Overcrowding is Unbalancing the World of Commodities. This can further complicate future forecasting efforts.

represents a program design element that allows the RPS requirement to disappear due to the CO_2 cap. This scenario uses natural gas at $3/MBTU for the last three phases of the program. In contrast, the other analyses presented here use a gas price of $5.50 for later years.

In this scenario, substituting combined cycle gas power for coal power is a relatively low-cost CO_2 reduction option for LSEs. The model can choose gas generation, net of CO_2 emissions associated with the technology, if it is the least cost mitigation option. Wholesale power prices are also reduced by 20 percent to be consistent with lower gas prices. Because gas power plants are often the last units dispatched, gas prices often affect the market price of wholesale power. This scenario is based on different generating costs and its cost impacts are not comparable with other scenarios. Rather this scenario is illustrative only to the extent that lower gas prices change the generation resource mix of the combined RPS and CO_2 cap:

- Should gas prices decline back to 1990s levels, then switching from coal to gas generation becomes a cheaper way to reduce CO_2 emissions than building new renewable generating plants.
- The total amount of renewables deployed under the climate policy (and the RPS) is reduced to less than 10 million MWh from the medium case of 16 million MWh, a reduction of nearly 40 percent.

These modeling results indicate that in a future low gas price environment Oregon is less likely to meet its renewables target with only the CO_2 cap and not the RPS as a backup. A CO_2 cap and a renewables portfolio standard can be viewed as complimenting each other under certain market and policy conditions, and as potential substitutes under others.[19] Barring perfect information about the future, it seems advisable to keep both the RPS program and the CO_2 cap-and-trade programs. Otherwise the ancillary benefits of renewables might be lost even if the CO_2 goals are met.

Another way to think about the relationship between the RPS and the CO_2 cap are their relative program goals. A renewable portfolio standard is typically considered to be an example of an *energy policy*: improve energy security, promote rural economic development, and diversify energy supply away from fossil fuel price variability and hydro availability. While the environmental benefits from renewables are often mentioned, these other goals should not be minimized. In contrast, a CO_2 cap is primarily an *environmental policy* focused on reducing the emission of climate changing gases. To reduce CO_2 by reducing demand or substituting gas for coal generation would not capture the energy policy benefits of renewables.

To the extent that these different policy goals result in both an RPS and a CO_2 cap, then the next question becomes how to design each program to minimize the compliance burden for regulated actors. Renewable energy certificates (whether combined with the power delivery or unbundled) will satisfy both the RPS and the CO_2 cap and reduce regulatory requirements. As the program enters the rulemaking stage, the accounting and

[19] See Nelson, H. (2006). *The Interactions Between Carbon Regulation And Renewable Energy Policies In The United Kingdom.* Dissertation manuscript.

procedural issues with compliance need to be streamlined and integrated between the two programs to minimize compliance costs.

Impacts of Increased Regional Demand for Oregon's Renewables Allocation

While the Task Force was developing a load-based cap-and trade proposal, California adopted AB 32, which mandates that the California Air Resources Board implement a cap-and-trade system, which could include a load-based system for the electricity sector. AB 32 was signed into law in October 2006. The bill leaves the specifics of program design to the rulemaking process and coordination with the CPUC. Also, Washington State appears to have passed Initiative 937, which mandates 15 percent renewables power sold in the state by 2020. These laws could increase competition for Oregon's renewable resources.

One key factor that will determine the demand for renewables from the Northwest power pool is the eligibility of unbundled renewable energy credits for compliance with state renewables and CO_2 programs. If power suppliers in California and other states need to have green power delivered to customers via the existing T&D system, then NW renewable resources like wind will stay within the region. However, if compliance for these programs can be met with unbundled renewable energy credits where the power is undelivered then demand on Northwest renewable resources from outside the Northwest is likely to be greater.

In the scenario to simulate the purchase of Oregon renewable power from *out of state*, the amount of renewable power available to Oregon in the model is reduced by 20 percent. This percentage reduction applies to the five renewable energy technologies in the model. See the appendix for more information on the model's renewable energy module. The model doesn't include generating technologies that are not yet fully competitive, including solar photovoltaic (PV), solar thermal, offshore wind, or wave power. It is likely that some of these technologies could be deployed before the last model year (2020) to comply with RPS or and CO_2 regulations. These additional technologies represent added supply that is not in the model and would alleviate price increases. This scenario is simply intended to inform decisionmakers how competition among states could impact program costs:

- The costs to ratepayers for the program (including the RPS) could increase from 6.5 percent in the final phase to 8.75 percent and the net present value of the benefits to Oregon are decreased to $250M.
- The estimated allowance price in the final phase doubles from $19 to $37.

Again, this is a highly stylized approach that doesn't allow for additional technologies to come online to because of state actions. Nonetheless, it does indicate the interdependence in program design between state climate and federal policies.

Conditions Under Which the Alternative Compliance Payment Is Triggered

The ACP is the mechanism that limits the program cost to participants by limiting the maximum amount an LSE would pay for an allowance. Given the multiple sources of considerable uncertainty in forecasting load growth, renewables costs and supplies, and fossil fuel prices these modeling results should be taken as indicative of possible outcomes, not predictive of future cost structures. This section reviews the analysis in this report, as well as other variables that could cause allowance prices to exceed the ACP level.

Reductions to renewables supplies will result in higher CO_2 prices than those estimated in the moderate load-growth case. Competition for renewables supplies from other areas in the West might push allowance prices nearer the ACP in the later years of the program. Increases in demand for mitigation are also likely to lead to increased allowance prices. The 2.7 percent load growth scenario shows the model broaching the ACP price. Similarly, under the medium load growth case with reduced energy efficiency deployment the model indicates the ACP might become a compliance strategy in the later years of the program.

Note that only in the 2.7 percent load growth scenario do forecasted allowance prices reach $40 for all three years in the last Phase of the program. The number of years that the model shows prices reaching the ACP is a proxy for the confidence of the model attaching claims to the likelihood of the event occurring. The following table indicates the *average* of the estimated allowance prices for the last three years of the program. The modeling indicates that of the scenarios considered here, only high load growth will cause the cap to be broken.

Table 6: Summary of Allowance Prices from the Six Scenarios

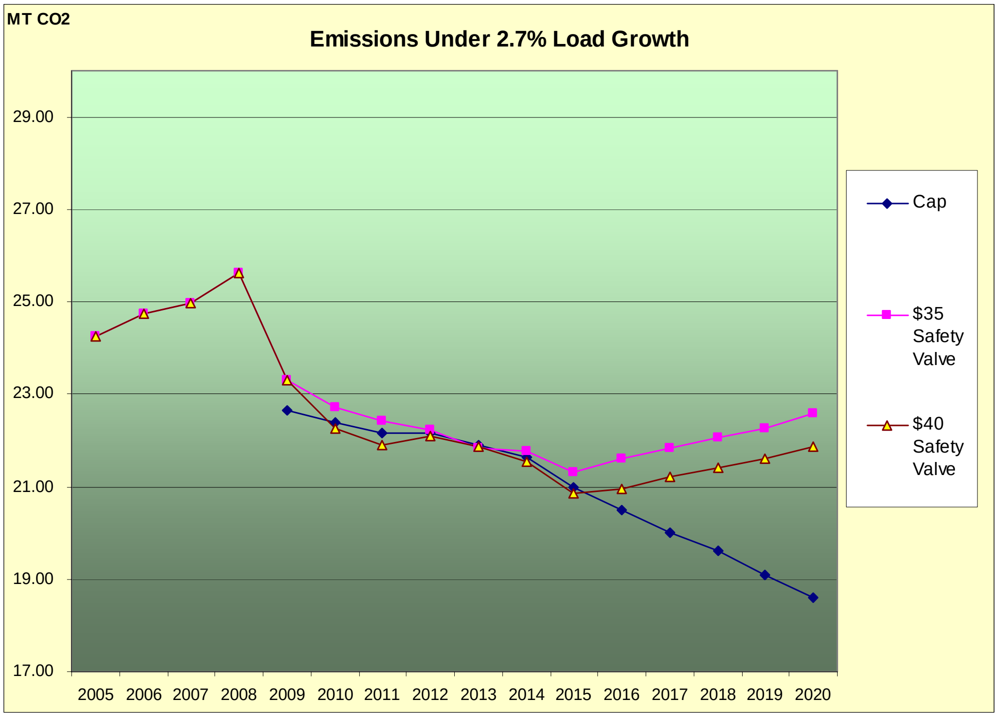
	0.7% Load Growth	**1.7% Load Growth**	**2.7% Load Growth**	**High Efficiency**	**Low Efficiency**	**Regional Demand**
Average of Phase IV Allowance Prices	$3.75	$21	$40	$13.50	$36	$37

Considerations in Lowering the Safety Valve Level to $35

The moderate load-growth case uses an alternative compliance payment level of $40 per metric ton. The initial modeling results presented here do indicate that the bulk of the supply of mitigation measures is below $40, which gives some empirical support to this level as a measure of when the system is "broken."

However, an alternative design would be to lower the ACP to $35. This impacts costs only in the high load growth case of 2.7 percent per year. The results of runs with a $35 ACP level were presented at the October Task Force meeting. The graph above shows the projected emissions trajectory for the two ACP levels under high load growth. The cap is broken in both cases: in 2014 and 2016 under the $35 and $40 ACP levels respectively.

Chart 2: Emissions Paths With $35 and $40 ACP Levels



The costs and benefits of the two levels can be estimated by looking at emissions and costs of the two design options. The reduction in the ACP level leads to a decrease in likely average rate impacts in the final phase from 10 percent to 9 percent and customer cost impacts are reduced by about $9 million. These cost savings results in fewer renewables and above market efficiency measures being deployed. Because CO_2 emissions associated with the $40 option stayed under the cap for a longer period of time, these emissions carry forward to the final phase of the program and the costs of the two alternatives can be compared. The $9 million per year average cost difference is associated with emissions reductions averaging 0.7 million tons of CO_2 per year for an incremental cost of $13 per ton.

CONCLUSION

The data presented here indicates that the load based CO_2 cap is a relatively low risk program. The climate policy brings significant bill savings to the state from increased energy efficiency. The RPS is cost effective as long as fossil fuel prices remain high. Aggressive early action from renewables and energy efficiency can facilitate much cheaper compliance later in the program as the cap declines. These early actions will help to moderate the largest source of risk to the load based CO_2 cap, that of fossil fuel based load growth.

The implication here is that the energy efficiency portion of the CO_2 cap needs to be implemented immediately to ensure these benefits to the state and to reduce both fuel price and policy risks. The sooner the RPS is implemented the better as this provides incentives for utilities to secure low cost renewables supplies from potential regional competition.

The analysis in this report has concentrated on Phase IV of the program because that is when the greatest reductions are required and thus when costs are likely to be highest. As has been noted throughout this report, current estimates of costs structures going out to 2020 should be treated with a *healthy dose of skepticism*. Making predictions about the future is difficult. While prudence dictates looking at Phase IV when costs are likely to be highest, it also the period with the greatest uncertainties.

Prudence also indicates weighing near-term considerations much more heavily than long term predictions as uncertainties are fewer. The futures market for oil and natural gas indicate that electricity costs are likely to remain high for the next several years at least. This will limit load growth even in strong economic growth conditions as evidenced by Oregon electric utility sales that were unchanged between 2004 and 2005.[20] High fossil fuel prices combined with the federal renewable production tax credit makes wind energy cost competitive.

The modeling shows that the CO_2 cap alone could provide statewide benefits of over $100 million a year through 2015. Even with the costs associated with the RPS, the implementation of both programs is likely to provide millions of dollars in net economic benefits to the state through at least 2015. Given these favorable cost considerations, Oregon is uniquely poised to provide leadership in reducing its climate footprint with a load based CO_2 cap on the power sector.

[20] ODOE data. Also consider that given compounding growth, if demand increases by only .7 percent (or less) for the precompliance phase (through 2008), then load growth would have to be well over 3 percent through 2020 to meet the worst case presented here. Thus, it appears highly unlikely that the 2.7 percent case will materialize.

Appendix

MODELING APPROACH

The Oregon Clean Energy Planning Model© is a customized Excel model for the Oregon Carbon Allocation Task Force. The model is intended to be used by stakeholders to better understand the most important policy variables in a carbon reduction program out to 2020. It is a modified capacity expansion model of annual load resource balances. The outputs from the model are intended to supplement traditional Integrated Resource Planning exercises that can give more detailed cost estimates.

The model relies on exogenous inputs to estimate program costs. Wholesale power prices, fossil fuel prices, renewable energy capital costs, energy efficiency resource potentials, and load growth estimates are the most important parameters in estimating future CO_2 mitigation costs. Due to these multiple sources of uncertainty some clean energy program proposals have not even tried to estimate cost impacts.[21]

Other modeling approaches have utilized CO_2 taxes on the emissions intensity of generation resources to change the merit order to less polluting resources in order to meet the CO_2 target. This approach is less appropriate here. First, the median Task Force proposal allocates 95 percent of allowances for free, so determining an average CO_2 price is a difficult task. Second, Oregon utilities still operate under cost-of-service regulation so generating resources are not determined by dispatch order but by the rate base. Finally, Oregon is a price taker in the Western wholesale power market and it is unclear how imposing an exogenous CO_2 price level for Oregon utilities will represent economic reality.

Instead of altering the merit order to meet CO_2 constraints as dispatch models do, the Oregon Clean Energy Planning Model achieves emissions reductions in discrete stages.

- Loads are estimated according to exogenous load growth parameters less assumed energy efficiency investments.
- Any new load growth required from thermal resources is added according to a pre-specified mix. The technical working group decided that the baseline new build resource mix should be 1/3 new pulverized coal, 1/3 new combined cycle gas, and 1/3 market purchases.
- CO_2 reductions from offsets are assumed to be purchased at the rate allowed by the offset parameter in the model.
- Renewable resources from an RPS can be included. To the extent that the RPS and climate policy reduces existing LSE resources, then the model reduces market purchases first, and if market purchases are zero then the model reduces thermal

[21] Washington regulators didn't even try to estimate the cost of a recent renewable energy initiative, stating; "The initiative's fiscal impact on Washington's local governments cannot be determined due to variables ranging from future fuel costs to changes in demand for electricity.
http://www.ofm.wa.gov/initiatives/937.asp

resources at their existing resource ratios. The algorithm leaves large hydro resources unchanged to the extent possible.

Major Input Assumptions

1. **Load Growth—**Load growth represents the most visible modeling parameter. Historical load growth in Oregon has ranged from high of 2.7 percent during 1987-1998 when power prices were low and/or only small amounts of energy efficiency investments were made, to essentially unchanged or decreasing loads during from late 1990s to 2004.[22] These load growths are net of all efficiency investments from both programmatic measures as well as market driven efficiency. The Northwest Power and Conservation Council's (Council) 5th plan forecasts demand growth range from 0.18 percent to 2.7 percent. The Council's AURORA model estimates annual demand growth for Western OR+WA at 1.06 percent and Eastern OR+WA at 0.42 percent.[23] Except as noted, the modeling runs in this report utilize a demand increase of 1.7 percent prior to programmatic efficiency investments.

2. **Avoided Costs—**Avoided power costs drive the cost of the CO_2 mitigation measures in the model and there are several possible categories of avoided costs to consider. Wholesale prices represent the opportunity cost of reducing generation which otherwise could be sold into the wholesale market. Another type of avoided cost is the cost of the resource(s) that are being shut off to meet the CO_2 cap. The technical work group decided that for the initial modeling runs, that the opportunity cost approach is preferred to calculate CO_2 costs.

3. **Energy Efficiency Supply Curves—**Energy efficiency investments are generation resources without CO_2 emissions. Energy efficiency deployment is assumed to come from either current practices or climate policy programs.
    - Current Practices assumes the existing 1.7 percent energy efficiency portion of the systems benefit charge in the IOU territory is extended statewide.
    - Climate policy assumes an additional 1.8 percent systems benefit charge to fund additional efficiency that will be undeveloped otherwise.
    - The model also includes above market energy efficiency measures for the climate policy. Above market resources are deployed when they are the least cost option and include air to air heat pumps, indirect evaporative coolers identified by the Council.

   The Energy Trust of Oregon's Conservation Resource Potential Assessment shows about 360 aMW supply by 2012 in the IOU territory only. If deployed in equal annual tranches this equates to about 50-60 aMW per year, or about 90 aMW per year statewide. Due to uncertainty about the long run energy efficiency supply curve, cumulative efficiency investments in 2020 are assumed to be capped at around 900 aMW. In the high load growth cases this limit is exceeded under the working assumption that more load growth equates to higher resource potential.

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[22] Phil Carver PPT presentation to the TASK FORCE on October 5th, 2006.
[23] NW Power and Conservation Council 5th Power Plan Appendix A.

Energy efficiency assessments typically assess the costs to local utilities to develop the efficiency supplies and assume that participants (end users) contribute a portion of the total resource cost in addition to utility incentives, program management costs, and delivery.

- The 5th Power Plan assumes that participants contribute 35 percent of measures cost and the Energy Trust assumes slightly less than half of the total cost is borne by participants.[24]

Below market energy efficiency funding from the climate policy is allocated according to load rather than as a percent of retail revenues as in the current systems benefit charge.

4. **Renewable Supply Curves—**The model allows users to input capital costs and learning curves for up to six types of renewable energy technologies with different cost tranches. Wind supply estimates are derived from the Council. Biomass, energy crops, and landfill gas come from the EIA Renewable Market Module, and geothermal come from the Western Governors' Association.

Nameplate Capacity MW	**2010**	**2015**	**2020**
Wind	1,500	3,500	3,500
Biomass	250	250	250
Energy Crops	250	250	250
Landfill Gas	148	148	148
Geothermal	118	280	500

Capital costs for the generating technologies used in this report come from a variety of sources including PGE and the Council. Learning curves for renewable and thermal resources come from the Council.

[24] The discussion of utility versus participant costs can be found on page D-4 of the Conservation Acquisition Appendix of the 5th Power Plan and in Elaine Prause's June 2006 Powerpoint presentation to the Task Force.

	2010 Cost MWh	2015 Cost MWh	2020 Cost MWh
Wind 1	$ 56.22	$ 44.06	$ 40.21
Biomass 1	$ 47.78	$ 44.18	$ 44.18
Energy Crops 1	$ 47.89	$ 45.74	$ 45.74
Geothermal	$ 40.56	$ 36.33	$ 34.31
LFG	$ 32.18	$ 29.48	$ 29.48
Wind 2	$ 60.99	$ 47.85	$ 43.71
Biomass 2	$ 52.64	$ 48.66	$ 48.66
Energy Crops 2	$ 51.94	$ 49.79	$ 49.79

The model also allows for CO_2 emissions from renewables such as integrating wind resources with gas generation. All tranches of wind are debited at 0.05 tons of CO_2 per MWh for integration into the system.

5. **Allocation of Renewables between Pacific and PGE—**In order for the model to reach a solution the supply of renewables must be allocated for each year and utility. This number represents how each regulated actor goes out and develops the renewables supply in the model. Estimating this number *a priori* is difficult because each utility will be different in how aggressively it pursues renewables energy projects. The technical working group decided that the best approach is to set the allocation so that the marginal costs between the Pacific and PGE are roughly equal in the later years of the program.

6. **Offsets**—Offsets are assumed to be purchased by all utilities at the limit allowed in the model. The median proposal caps offset purchases at 1.9 percent of total CO_2 allocation for all LSEs except for the COUs, which can purchase up to their entire allocation. The offset supply curve in the model is a synthesis of estimates from the Climate Trust and offset projects developed by the Prototype Carbon Fund adjusted for labor costs and inflation.

7. **Fossil Fuel Prices, Renewables Incentives, and Integration Costs—**The model allows for the user to input these parameters. These parameters remain unchanged in all scenario presented here except as noted.

	Precompliance Period	**Phase I**	**Phase II**	**Phase III**	**Phase IV**
	2005-2008	2009-2011	2012-2014	2015-2017	2018-2020
Intermittent Resource Integration Cost $/ MWh	$ 6.00	$ 6.00	$ 6.00	$ 7.00	$ 7.00
Production Tax Credit $/ MWh	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00
Gas Price $/MBTU	$ 7.00	$ 7.00	$ 5.50	$ 5.50	$ 5.50
Coal Price $/MBTU	$ 1.00	$ 1.00	$ 1.27	$ 1.27	$ 1.27