Turning the Corner on Global Warming Emissions: An Analysis of Ten Strategies for California, Oregon, and Washington

REVISED DRAFT
July 28, 2004

ALISON BAILIE
BILL DOUGHERTY
CHARLIE HEAPS
MICHAEL LAZARUS
TELLUS INSTITUTE

UNDER THE SUPPORT AND DIRECTION OF
THE ENERGY FOUNDATION

FOR THE
WEST COAST GOVERNORS' GLOBAL WARMING INITIATIVE

Foreword
By the Energy Foundation

This analysis of strategies to reduce greenhouse gas emissions in was undertaken to advise the West Coast Governors' Global Warming Initiative. It is an assessment of selected strategies that California, Oregon, and Washington could use to turn the corner on global warming pollution.

This report makes a compelling case that the West Coast states can significantly global warming emissions over the next 15 years. By 2020, the ten strategies in this report would reduce global warming pollution by 200 million metric tons—26 percent below the emissions that would otherwise occur, and 1 percent below today's levels. This is a significant achievement given the assumptions of significant economic growth, on the order of 75 to 80 percent from 2000 to 2020, that underlie the region's energy use projections. While these reductions are not nearly enough to stabilize the climate—scientists agree that reductions of 75 percent or more will be necessary over the long run—the ten strategies would represent a significant down payment on deeper emissions reductions. Emissions would be on a downward path, rather than continuing dangerously upward.

This analysis may understate the potential to reduce global warming pollution, for several reasons. It assumes no federal action to reduce CO_2, which could make regional reductions easier and deeper. More importantly, the ten strategies in this report do not exhaust the means to reduce emissions. For example, forest and agricultural carbon sequestration, reductions of global warming gases other than CO2, industrial process emissions reductions, transportation modal shifts, and many other strategies are not addressed. Any global warming pollution target should take into account the additional reductions possible from these other measures.

These strategies can be pursued at a short-term profit to the public. Just considering the direct costs and savings of these strategies—ignoring the benefits of reducing global warming itself—the savings are significant both in the short and the long term, summing to nearly $40 billion from 2005 to 2020 on a net present value basis. This figure also ignores the co-benefits, such as reduced smog and cancer-causing particulates, that would result from these strategies. In the short run, the efficiency strategies will save consumers billions on energy costs, fossil fuel prices will fall with the reduction in demand, and the region will benefit from reduced energy price volatility. Over the longer run, these strategies will ensure the West Coast's continued technological leadership by promoting advanced energy efficiency and renewable technologies—technologies that will be the foundation of economic growth throughout the world in the 21st century.

The region's Governors have shown long-term vision by launching and supporting the West Coast Global Warming Initiative. We hope this report helps to strengthen that commitment, assist in the development of pollution reduction goals, and justify the belief that the region can turn the corner on global warming emissions.

Acknowledgments

We wish to thank David Wooley and Marcus Schneider of the Energy Foundation for their encouragement and support for this work. We greatly appreciate the time spent by that numerous state officials and agency staff providing directional guidance, and pointing us to helpful reports and data sources. These include, among others: Phil Carver, Jeff Goby, and Sam Sadler at the Oregon Office of Energy, Liz Klumpp and Greg Nothstein at the Washington State Department of Community, Trade and Economic Development, Susan Brown, Gerry Bemis, Pierre duVair, Angela Tanghetti, Chris Kavalec, Al Alvarado, Adam Pan, Jason Orta at the California Energy Commission, and Chuck Shulock, Doug Thompson, and Eileen Tutt at the California Air Resources Board. In addition, Ralph Cavanagh, Angus Duncan, KC Golden, Roland Hwang, Noah Horowitz, Steve Nadel, Jeff Johnson, Kathryn Phillips, Greg Dierkers, and Polly Shaw all provided valuable comments and technical inputs.

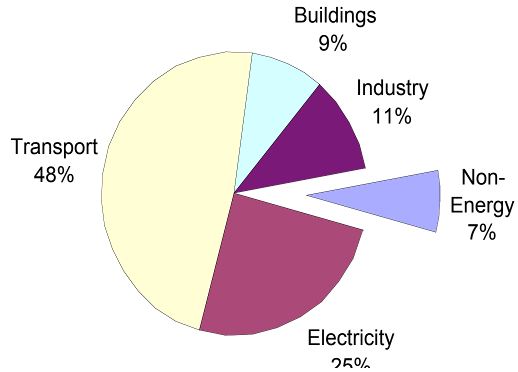
Turning the Corner on Global Warming Emissions: An Analysis of Ten Strategies for California, Oregon, and Washington

Table of Contents

Executive Summary

This report assesses ten broad strategies to reduce greenhouse gas emissions in California, Oregon, and Washington. It provides an input to the West Coast Governors' Global Warming Initiative (WCGWI), and its deliberations on targets and timetables for region-wide emissions reductions.

Figure 1. GHG emissions by source, all three states, 2000



Non-energy emissions represent 83 MMTCO2e minus a 40 MMTCO2e ag/forestry net sink.

These ten strategies, listed along with their key assumptions in Table 1 below, address the main sources of energy-related greenhouse gas (GHG) emissions: fossil fuel use in transportation, electricity supply, buildings, and industry. We focus on these sources because they are the major sources of GHG emissions in the region, accounting for over 90% of net year 2000 emissions, as shown in Figure 2. However, within these broad categories, there are several important emissions sources that these strategies do not address, such as jet fuel use or port-related emissions. Non-energy sources of emissions are likewise not considered. It is therefore important to recognize that **this suite of strategies does not exhaust the full range of potential emissions reducing options**. Several of the options not considered here, yet promising in terms of emissions reduction and other local benefits, are listed in Box 1. A supplemental assessment of reductions possible from these other options may be needed.

Table 1. The ten strategies considered in this analysis

Strategy Title	Description
Codes and Standards	New appliance efficiency standards in all states; WA non-residential building code upgrade
Efficiency Programs	Achievable cost-effective gas and electric efficiency potential, captured through public benefit (goods) charge and/or efficiency portfolio standard.
Industry Carbon Policy	Achievable, cost-effective reduction in fossil fuel use, via carbon emission standards, voluntary commitments, *or* point source carbon cap & trade.
Combined Heat and Power	Barrier removal and incentive programs to increase penetration of CHP in industrial and commercial sectors.
Renewable Portfolio Standard (RPS)	Retail electricity providers deliver renewable resources (or tradable credits) equivalent to 33% of 2020 sales in CA, 20% in OR and WA.
Electricity Sector Carbon Policy	Carbon emissions portfolio standard *or* carbon cap and trade system, modeled as cap and trade with permit price of $20/tCO2.
LDV GHG Emission Standards	Light duty vehicle standards start in 2009, reach 30% improvement (gCO2e/mi) for new vehicles sold in 2014, 50% for new vehicles in 2020.
Alternative Vehicle Fuels	Hydrogen fuel cell vehicles meet 2% of new vehicle sales, and blending of 10% cellulosic ethanol, 20% biodiesel in gasoline and diesel by 2020.
Travel Reduction Efforts	Reduction in vehicle miles traveled (VMT) of 5% by 2020, through a combination of region-specific initiatives (smart growth, transit, etc.)
HDV GHG Emissions Improvement	Reduction of heavy duty emissions rates (gCO2eq/mi) by 20% in 2020 through incentives and standards.

Box 1: Selected greenhouse gas measures not addressed in this analysis

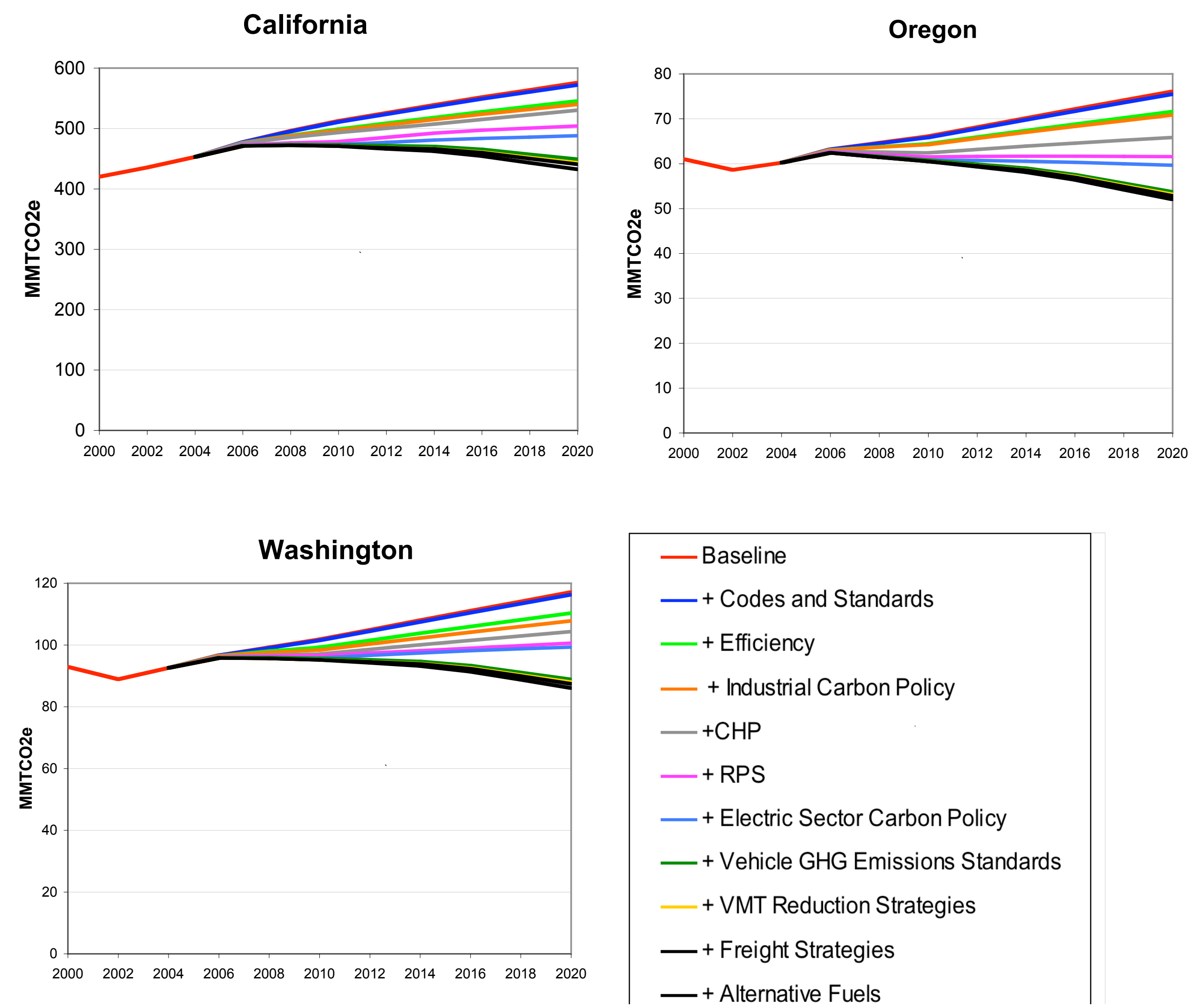
- Jet fuel use reduction through high-speed rail, promotion of air travel alternatives and more efficient aircraft (e.g. Boeing's new 7E7).
- Low GHG building design and advanced building codes.
- Fuel switching from coal to oil to gas industry.
- Reductions in the use of diesel generators on ships at West Coast ports.
- Land use measures.
- Truck stop electrification.
- Congestion management.
- Moving road freight from trucks to rail.
- Response to awareness and education efforts, and changes in consumption patterns.
- Low rolling-resistance replacement tires.
- New or improved technologies and practices that emerge over the coming fifteen years, such as significantly lower cost solar photovoltaic technology.
- Increased carbon sequestration on farms and in forests.
- Reductions of non-CO2 global warming gases from agriculture, waste, and industry.
- Industrial process emissions reductions (e.g. cement).
- Standards for additional appliances (e.g. some proposed for California such as pool heaters) and tighter standards for federally regulated appliances (i.e. requiring preemption)

The results of this analysis suggest that **the ten strategies assessed here could help the states turn the corner on rising energy-related greenhouse gas emissions**. As shown by the lower lines in Figure 2, if these strategies were implemented, energy-related GHG emissions in each state could begin to stabilize within the next few years, and then begin a downward turn. This outcome contrasts with the base case scenario shown by the top lines in these charts. **Without new policies and actions[1], the region's energy-related emissions might otherwise rise by over 30% from 2000 to 2020**, an increase of roughly 200 million metric tons of carbon dioxide equivalents (MMTCO2e) from current levels[2].

[1] The base case scenario includes policies under implementation today, such as California's 20% renewable portfolio standard (by 2017).

[2] Note that our historical emissions figures are somewhat higher than those found in official state inventories, since we include the emissions associated with imported electricity. See Sections 1 and 5, and Appendix B for further explanation of the consumption-based electricity accounting approach used here, which is based on state fuel mix estimates.

Figure 2. GHG emissions from energy-related sources, base and strategy cases



These results are summarized and compared with historical emissions by states in Table 2. Details by strategy are provided in Table 3. With the implementation of these ten strategies, energy-related GHG emissions could begin to decline in Oregon and Washington over the next few years, with emissions dropping to near 2000 levels by 2010 and below 1990 levels by 2020 or shortly thereafter. In California, a more dominant transportation sector and faster expected economic growth mean that emissions begin falling after 2010, and could return close to 2000 levels by 2020.

The focus on the 2020 time frame should be kept in context. The ultimate goal of global warming policy -- stabilization of atmospheric GHG concentrations at levels that avoid dangerous interference with the climate system -- will likely require far deeper emissions reductions, on the order of 75% below current levels. As discussed below, several of the strategies considered here, especially the transportation ones, will pay even larger dividends after

2020. Therefore, **this set of strategies may have even greater value over the long run than emissions reduction estimates for 2020 might suggest.**

Table 2. Contribution of ten strategies to reducing energy-related GHG emissions

	Energy-Related Emissions (MMtCO2e)			
	1990	**2000**	**2010**	**2020**
California				
Base Case Emissions	408	424	516	579
Emissions after Strategies			474	436
Emissions relative to base case			*-8%*	*-25%*
Emissions relative to 2000			*+12%*	*+3%*
Emissions relative to 1990			*+16%*	*+7%*
Oregon				
Base Case Emissions	53	62	67	77
Emissions after Strategies			61	53
Emissions relative to base case			*-8%*	*-31%*
Emissions relative to 2000			*-1%*	*-15%*
Emissions relative to 1990			*+16%*	*-0%*
Washington				
Base Case Emissions	85	94	103	118
Emissions after Strategies			96	87
Emissions relative to base case			*-6%*	*-26%*
Emissions relative to 2000			*+2%*	*-7%*
Emissions relative to 1990			*+13%*	*+2%*
Regional Total				
Base Case Emissions	545	579	685	774
Emissions after Strategies			631	575
Emissions relative to base case			*-8%*	*-26%*
Emissions relative to 2000			*+9%*	*-1%*
Emissions relative to 1990			*+16%*	*+6%*

Differences between the states

Among the three states, Oregon shows the steepest potential declines in energy-related GHG emissions, followed by Washington, and then California. These differences are the result of a number of factors, including, most prominently:

- **Coal in the electricity mix.** Among the three states, Oregon has the highest fraction of coal in its current electricity mix. These ten policies back out much of this coal-based electricity, and as a result drive emissions down more steeply in Oregon than in Washington and California.

- **Different economic growth assumptions.** The underlying projections of economic growth and fuel use are higher for California than for the other two states. Under our base case scenario, California emissions grow at a rate of 1.6% per year, in contrast with Oregon and Washington, which both grow at 1.1% and 1.2% per year, respectively. These estimates draw heavily on projections done at the state and regional level (see Section 1 below), and reflect higher population and economic forecasts for California. Faster growth in energy use simply makes it harder to achieve the same level of emissions reductions in California.
- **California air travel.** High levels of jet fuel use in California – for in-state and other domestic US travel — total 13% of current emissions. High rates of projected growth in jet fuel use (3% per year) would add another 34 MMTCO2e to the state's emissions between 2000 and 2020, or over 20% of the projected emissions growth during that time.

Notes on the strategies

As shown in Table 3, the four transportation strategies considered here*, because they focus largely on new vehicles and phase in over the 2010-2020 period,* do relatively little to reduce emissions prior to 2010. The most potent of these strategies, light duty vehicle GHG emissions standards, as well the freight efficiency strategy, are assumed to come into effect in 2009, ramping up gradually from 2010 to 2020. Because of the lag time in vehicle stock turnover, it takes several years before these strategies have their full effect. In fact, emissions reductions from these transportation strategies should increase significantly in the years after 2020*,* as the on-road vehicle fleet increasing reflects the major technological improvement in new cars purchased during the next decade. Similarly, many travel reduction strategies, such as smart growth and transit investments, can take decades to show their full effects.

By contrast, the six strategies in buildings, industry and electricity supply—codes and standards, efficiency programs, industrial fuel use reductions, combined heat and power, renewable portfolio standards, and electricity carbon policy—rely on technologies that are commercial and widely available in today's market, such as efficient lights and motors, improved building designs, wind turbines, or CHP units. As a result, major reductions in fossil fuel use might be achieved *more rapidly* in buildings, industry, and electricity supply than in the transportation sector, at least from the types of technology-push strategies considered here.

Table 3. Summary of CO2 Impacts by Strategy

	Emissions (MMtCO2e)					
	CA		OR		WA	
	2010	2020	2010	2020	2010	2020
Energy Emissions (Base Case)	516	579	67	77	103	118
Emissions Reductions						
Buildings and Industry Strategies						
Codes and Standards	2	4	0	1	0	1
Efficiency Programs*	12	27	1	4	2	6
Industry Carbon Policy	2	6	0	1	1	3
Combined Heat and Power*	4	10	2	5	1	3
Electricity Supply Strategies						
Renewable Portfolio Standard	15	26	1	4	0	4
Electricity Sector Carbon Policy	5	16	1	2	1	1
Transportation Strategies						
Light Duty Vehicle GHG Standards	0	39	0	6	0	10
VMT Strategies*	2	6	0	1	0	1
Freight Strategies	0	2	-	0	0	1
Alternative Fuels*	(0)	9	-	1	(0)	1
Total Reductions	42	144	6	24	7	31
Emissions After Strategies	474	436	61	53	96	87
Percent Reduction (vs Base Case)	8%	25%	8%	31%	6%	26%

Zero values reflect reductions of less than 0.5 MMtCO2e

The key results to draw from Table 3 are the overall emission reductions across all of the strategies. There are important interactions among strategies that make assigning precise emissions reduction to individual strategies rather difficult. Efficiency, renewable, and CHP resources, for example, all reduce the need for conventional fossil-based electricity generation. Our electricity modeling approach looks at the combined impact of these policies, and we then allocate overall emissions reductions back to the individual strategies. For other fuels, we evaluate the strategies in sequential order, and thus strategies lower down the list, such as alternative vehicle fuels, would yield greater emission reductions than if they were evaluated first. Similarly, several of these policies, such as **utility carbon policy, renewable portfolio standards, travel reduction efforts, and alternative vehicle fuel strategies would produce significantly greater emissions reductions than shown here** were they considered in the absence of other strategies (e.g. efficiency programs and vehicle standards) that eliminate emissions they would otherwise address.

Cost analysis

Together, the ten strategies appear capable of being a significant economic boon to the region. We performed an analysis of the direct economic impacts of these measures (but not a full cost-benefit analysis, for reasons described below). As shown in Table 4 below, direct economic savings to the region could approach $10 billion per year by 2020, and total nearly $40 billion on a cumulative basis (discounted at 5% real). These results are driven largely by energy efficiency (programs, codes and standards) and GHG standards for light duty vehicles. These strategies account for nearly half the estimated emissions savings by 2020, and nearly 90% of the net economic benefit. This large benefit is due to large potential for cost-effective technology improvements that reduce electricity, natural gas, and gasoline bills.

In the short run, efficiency strategies for buildings and industry are likely to yield the greatest cost savings, since they can be implemented immediately using technologies readily available in today's market. Annual cost savings from efficiency programs, codes, and standards, could reach $1 billion by 2010, approach $3 billion by 2020, and total over $13 billion in NPV terms by 2020.

Table 4. Summary of Cost Savings, all 3 states ($billion)

	Cost Savings in year:		**Cumulative NPV Savings (2005-2020)**
	2010	**2020**	
Buildings and Industry			
Codes and Standards	$0.3	$0.8	$3.6
Efficiency Programs	$0.7	$2.1	$9.9
Industry Carbon Policy	$0.2	$0.3	$1.9
Combined Heat and Power	$0.2	$0.5	$2.5
Electricity Supply			
Renewable Portfolio Standard	$0.1	$0.1	$0.5
Electric Sector Carbon Policy	-$0.2	-$0.6	-$3.0
Transportation			
LDV GHG Standards	$0.4	$6.3	$21.5
VMT Strategies	$0.6	$1.4	$7.5
Freight Strategies		$0.1	$0.2
Alternative Fuels		-$1.5	-$4.8
Total	**$2.1**	**$9.4**	**$39.7**

Positive number indicates a net savings; negative number indicates a net cost
** All results are in 2002 dollars, with NPV figures discounted back to 2005 at a 5% real discount rate.*

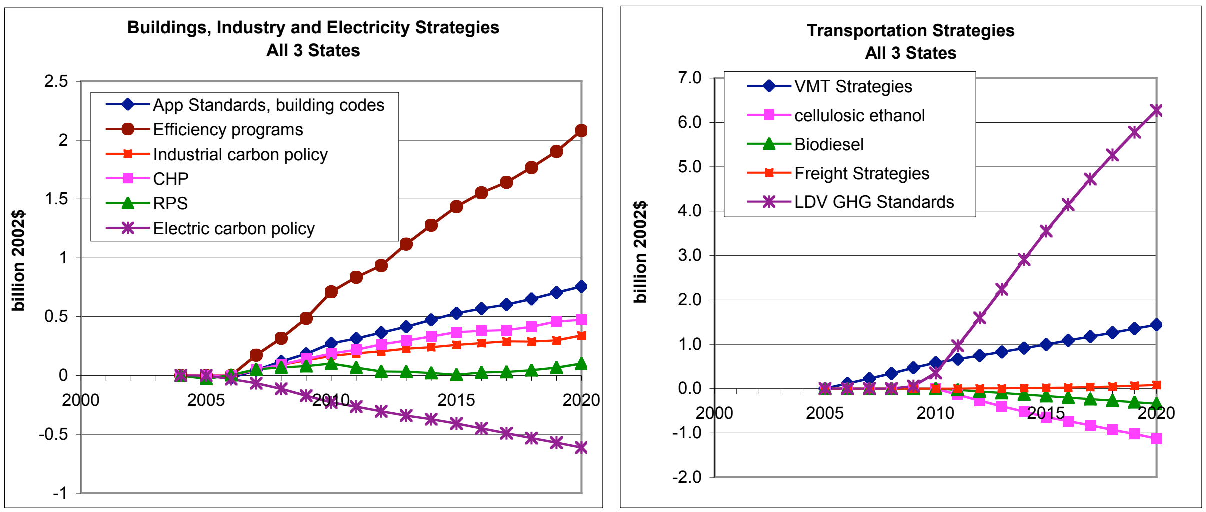
LDV GHG standards, phased in starting in 2009, would save the three-state region only about $400 million in 2010, but the benefits rise continuously as the stock of vehicles turns over. By 2020, consumers save at least $6.3 billion a year by 2020.[3]

Several other strategies appear to yield a net economic benefit. The industrial carbon policy could yield nearly $2 billion in NPV benefits by 2020, if designed to effectively capture the significant potential to cost-effectively reduce the direct use of fossil fuels in major industries.

[3] This figure is based on the CARB staff proposal, and it is probably a low estimate for the policy measure considered here. While the LDV GHG standard analyzed in our draft report is similar to the CARB staff proposal in near-term and mid-term – reducing new car emissions 30% by 2014 – it also considers longer-term technologies that could cut new vehicle GHG emissions in half by 2020. As a result, GHG savings are significantly higher than in the CARB staff proposal, and the net cost savings are likely to be significantly higher as well.

Combined heat and power, by using natural gas more efficiently, could potentially provide economic benefits of over $2 billion in net present value by 2020. Heavy-duty vehicle GHG emissions reductions, as modeled here, could yield a small net savings ($0.2 billion NPV by 2020). These savings are far more modest that those estimated for the LDV GHG emissions standards, over $20 billion NPV by 2020, because of the more limited improvements, slower turnover in heavy truck stocks, and the lower costs and volume of diesel use. Vehicle travel reduction strategies capable of decreasing miles traveled by 5% would reduce gasoline expenditures by nearly $8 billion. We did not try to estimate the complex set of costs and benefits associated with implementation measures such as transit or smart growth.

Figure 3. Annual Net Cost Savings of Individual Strategies, 2005-2020



We find that the renewable portfolio standards are a roughly breakeven strategy on a direct cost basis ($0.5 billion net NPV savings by 2020).[4] Other strategies, such as electricity sector carbon policy and alternative vehicle fuels come at a net direct cost. Because it encourages, in part, switching from coal to higher-cost natural gas, and from older plants to new more energy-efficient plants, the electric sector carbon policy imposes costs, which might sum to about $3 billion cost in NPV terms by 2020. These costs, however, are likely to be much smaller than the savings from efficiency strategies noted above. They are also small compared to the overall costs of generating electricity; they would add about 1% to total electricity supply costs.

As shown in the Appendix C, many assumptions lie behind these estimates. They include the capital, operating, and fuel costs of various technologies. The capital costs of many renewables, such as wind and solar, have decreased substantially in the past couple decades as more plants have been built and run. Costs of fossil plants have also dropped in that time. The future costs of plants will also evolve - decreasing with improvements in plant design but possibly increasing with higher energy prices or as the best wind sites are developed forcing new builds in more costly areas.

[4] Our analysis includes the added transmission and capacity costs associated with intermittent wind resources. Under current and expected future costs for technologies and fuels, renewable electricity sources may be slightly less expensive overall than fossil-fueled sources on average, though the differences are small and are highly sensitive to variations in cost estimates.

The large-scale introduction of alternative biomass-based fuels appears to be the highest cost strategy considered. Both cellulosic ethanol and biodiesel are estimated to cost over twice as much as the fossil fuels they would replace, on a per BTU basis. For these fuels, the co-benefits of fuel diversity, reduced import dependence, and regional job creation are important motivators.

Costs and savings are quite similar across the three states, as illustrated in Table 5. Costs and benefits are largely proportional to each state's share of overall emissions reductions. The principal economic difference results from the underlying higher costs of electricity supply to California consumers. As a result, California is likely to experience somewhat higher economic savings from similar levels of investment in efficiency and renewable resources. This explains the finding that an RPS is net economic gain in California, while a net cost in Washington.

Table 5. Individual State Results, Cost Analysis

	2020 Annual Cost Savings			Cumulative NPV Savings (2005-2020)		
	CA	**OR**	**WA**	**CA**	**OR**	**WA**
Buildings and Industry						
Codes and Standards	$0.5	$0.1	$0.2	$2.5	$0.3	$0.8
Efficiency Programs	$1.6	$0.1	$0.4	$7.5	$0.6	$1.8
Industry Carbon Policy	$0.2	$0.0	$0.1	$1.1	$0.2	$0.6
Combined Heat and Power	$0.3	$0.0	$0.1	$1.8	$0.1	$0.6
Electricity Supply						
Renewable Portfolio Std	$0.2	$0.0	-$0.1	$1.3	$0.0	-$0.8
Electric Sector Carbon Policy	-$0.4	-$0.1	-$0.1	-$2.1	-$0.5	-$0.4
Transportation						
LDV GHG Standards	$4.4	$0.7	$1.2	$15.2	$2.3	$4.1
VMT Strategies	$1.2	$0.1	$0.2	$5.9	$0.6	$1.0
Freight Strategies	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0
Alternative Fuels	-$1.2	-$0.1	-$0.2	-$3.8	-$0.4	-$0.6
Total	**$6.9**	**$0.8**	**$1.8**	**$29.5**	**$3.2**	**$7.0**

Key costs and benefits not considered

This analysis is by no means a full cost-benefit analysis, for four main reasons.

1. It does not quantify the environmental and other co-benefits associated with many of these strategies – such as lower air pollutant emissions and reduced import dependency -- which could be quite significant.
2. It does not consider the indirect and macroeconomic impacts that would arise as energy savings are "re-spent" on local goods and services, as consumers respond to changes in energy prices, and as investments and jobs shift towards renewable and efficiency products.
3. It does not explicitly consider the effects of reduced demands on gasoline, natural gas, and other fuel prices. These demand reductions are likely to decrease prices, yielding an

economic benefit, as well as leading to some increase in fuel use owing to lower prices (the rebound effect).[5]

4. **The benefit of reducing GHG emissions themselves—the key element necessary for a full cost-benefit analysis—is missing.** The ultimate benefit of greenhouse gas reduction strategies is the avoidance of climate change risks and damages. However, these are notoriously difficult to quantify in dollar terms, given both scientific uncertainties and valuation challenges, such as putting a price tag on lives or ecosystems. One can also look at the benefits of limiting exposure to future GHG regulatory requirements at the national and international levels.

One must consider all of these benefits, not just the costs and savings listed, to adequately judge the economic merits of proceeding with strategies that appear to have overall net direct costs.

Conclusion

These ten measures are illustrative of the actions available to the three states to reverse the trend of ever-growing emissions of green house gases. The list should not be considered exhaustive, however. At least three other categories of actions are available to continue and accelerate the downward sloping emissions line.

First, there are other actions available today to the states, including reduction of diesel emissions at truck stops and at ships in port or high-speed rail in the I-5 corridor. The potential benefits of these and other options, such as those listed in Box 1, are not estimated here. Each of the three states is compiling its inventory of such actions.

Second, some actions are available to the Federal government but not to the states. These include implementation of a broad carbon cap-and-trade system, new federal appliance standards, and development of hydrogen fuel cycle and sequestration technologies, among others. A serious partnership between the two levels of government would also accelerate the pace of emissions reductions.

Third, there will be technological and societal opportunities in the years ahead that are not widely available today. Just as compact fluorescent light bulbs were an unknown technology 20 years ago but are standard equipment today, other technologies are likely to come forward—particularly if state or federal leadership create new market opportunities. To cite only the most obvious, the cost of photovoltaic conversion of sunlight to electricity should decline and could become standard practice in roofing, siding and window materials. Solar efficiencies will continue to gain and installed costs will drop with industry experience and manufacturing economies of scale, just as they did for wind technology in the 20 years since 1980 (to a level that is cost-competitive with electricity from new gas turbines today).

The ten measures analyzed in this paper should be regarded as the down payment on a much larger set of necessary, practical and advantageous choices that will be available to future decision-makers.

[5] An analysis performed by ACEEE estimates that energy efficiency and renewable energy strategies like those considered here reduce wholesale natural gas prices by 20% by 2008 in West Coast states. *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*, American Council for an Energy-Efficient Economy, http://aceee.org/energy/efnatgas-study.htm

1. Introduction

The West Coast Governors and their staffs have undertaken the challenge of crafting climate policy amid many political, social, and economic uncertainties. To avoid long-term climate disruption requires decisive action and commitment. Global greenhouse gas (GHG) emissions are rising rapidly, and GHG emissions *reductions* of 50-80%, relative to current levels, may be needed by the end this century to avoid dangerous interference with the climate system.

The states of California, Oregon and Washington currently account for 2.4% of the world's GHG emissions, and 8.9% of US emissions.[6] Thus the actions of West Coast states could have a profound influence not only on their own emissions, but send a strong signal through out the US and the rest of the world.

The states' Governors are already moving rapidly to action, and are advancing policies and measures across many key areas that promise significant emissions reductions, as well as many other economic and environmental benefits.

One of the key uncertainties the Governors face is how far and how fast emissions can be reduced while preserving -- and perhaps even significantly enhancing -- the robustness of their constituent communities and economies. This analysis is intended to help address some of this uncertainty, by scoping out the potentially achievable emissions reductions from a few broad strategies. Some of these strategies are already on the drawing boards – GHG vehicle emissions standards, appliance efficiency standards, and the more rapid introduction of alternative fuel vehicles and renewable electricity generation – to varying degrees across the 3 states. Others, such as utility carbon policy (e.g. cap and trade), are only beginning to undergo consideration in the West Coast, while they are being actively pursued in other parts of the country.

This analysis seeks to address the following questions: What if ten strategies, as listed below in Table 6 were pursued across all 3 states? How much emissions reduction could be reasonably achieved by 2020? If implemented, what sorts of benefits might they provide?

The goal of this exercise is not definitive assessment of each strategy, but rather to present plausible initial estimates in order to guide further analysis, inform the Governors' consideration of regional cooperation on climate protection, and complement existing analysis efforts at the state level. A few of the strategies on this list are currently being quantified by individual states, such as appliance efficiency standards or vehicle GHG emissions standards. As described in the sections below, the assumptions about technologies considered and the extent of policy implementation may not match precisely what the states are presently considering.

[6] Based on West Coast emissions as estimated below (consumption-based electricity accounting)

Table 6. Strategies considered in this analysis

Strategy Title	Description
Codes and Standards	New appliance efficiency standards in all states, and building code upgrade (WA non-residential only)
Efficiency Programs	Achievable cost-effective gas and electric efficiency potential, captured through public benefit (goods) charge and/or efficiency portfolio standard.
Industry Carbon Policy	Achievable, cost-effective reduction in fossil fuel use, via carbon emission standards, voluntary commitments, *or* point source carbon cap & trade.
Combined Heat and Power	Barrier removal and incentive programs to increase penetration of CHP in industrial and commercial sectors.
Renewable Portfolio Standard (RPS)	Retail electricity providers deliver renewable resources (or tradable credits) equivalent to 33% of 2020 sales in CA, 20% in OR and WA.
Electricity Sector Carbon Policy	Carbon emissions portfolio standard or carbon cap and trade system, modeled as cap and trade with permit price of $20/tCO2.
Vehicle GHG Emission Standards	Light duty vehicle standards start in 2009, reaching 30% improvement (gCO2eq/mi) for new vehicle sales by 2014 and 50% by 2020.
Alternative Vehicle Fuels	Hydrogen fuel cell vehicles up to 2% of new vehicle sales and blending of 10% cellulosic ethanol, 20% biodiesel in gasoline and diesel by 2020.
VMT Strategies	Reduction in vehicle miles traveled (VMT) of 5% by 2020, through a combination of region-specific initiatives (smart growth, transit, etc.)
Freight Strategies	Reduction of heavy duty emissions rates (gCO2eq/mi) by 20% in 2020 through incentives and standards.

The ten strategies analyzed here represent only a fraction of potential GHG emission reducing efforts that could be contemplated within the WCG WGI process, as well as outside it. Thus, the results of this analysis, while reflecting a likely initial suite of policies and measures, may not indicate the full extent of emissions reductions possible by 2010 and 2020. In particular,

- Due to limited time and resources, we focus exclusively on energy-related GHG emissions[7] and strategies. While these account for over 90% of the region's current greenhouse gas emissions, other sectors may provide the potential for large reductions (e.g. landfill methane) or significant net carbon sequestration (e.g. agricultural management, maintenance of forest and other natural land cover) during the timeframe of analysis (to 2020).
- Charts and tables presented here do not include the potential emissions benefits of strategies such as low rolling resistance replacement tires, truck stop electrification, port and airport management, or advanced building codes that are being considered across the region, but are not analyzed here.
- Some strategies, such as geological carbon sequestration, or changes in settlement and consumption patterns, may yield limited emissions reductions by 2020 yet prove essential for a longer-term transition to a low-carbon economy. These types of strategies are beyond the scope of this report.

1.1 Analysis Approach and Data Sources Used

Our starting points for this analysis are the various inventory reports, policy documents, forecasts, and strategy papers prepared by agencies in each state. We then consulted with a number of state energy experts (see acknowledgements) to gain a better understanding of current

[7] We do include nitrous oxide (N2O) and methane (CH4) emission from fuel use.

emissions patterns and insights into current policy analyses and issues. Our next step was to construct a base case projection reflecting expected trends through 2020, inclusive to the extent possible, of policies already approved (such as the California Renewable Portfolio Standard). This base case projection is described in the next section.

We constructed the series of strategy analyses described in Sections 2 through 4 below. These were then assembled using Tellus' LEAP software[8], to allow integrated tracking of emissions impacts across the three states. In addition, we employed Tellus' in-house version of the US Department of Energy's National Energy Modeling System (NEMS), which considers detailed demand-supply interactions, and provides insights on costs, benefits, price impacts, and emissions reductions. We used the NEMS model to track regional energy system responses to the suite of strategies analyzed here, as described in further detail in Appendix A. To assist in evaluation of transportation strategies, we calibrated and used a simple vehicle stock turnover model for each state.

Another key feature of our analysis approach is the accounting of electricity emissions based on the sources of generation used to meet state demands. This differs from production-based accounting methods such as those used in state inventories, which only include emissions from power plants physically located in-state. Consumption-based accounting has the advantage of better reflecting the emissions associated with electricity use, and with policies that change electricity use or generation sources. See Section 3 and Appendix B for further discussion.

1.2 Base Case Projections

Using the data sources and assumptions indicated in Table 7, we developed base case projections of energy use in each state through 2020. These base case projections assume a continuation of expected trends in most sources, and to the extent possible, reflect the implementation of enacted policies, such as California's current RPS, and California and Oregon's public benefit charges. Therefore in the base case scenario, RPS-qualifying renewable resources provide 20% California's electricity by 2017. And a significant fraction of the region's energy efficiency potential is assumed to be captured under business-as-usual conditions (See Appendix D).[9] However, we do not include policies such as the California Pavley vehicle standards that have not yet been implemented.

Figure 4 shows the resulting energy use projections by state and by sector. Figure 5 shows the resulting breakdown in final energy consumption by fuel over the period 2000 to 2020. These charts highlight the continuing importance of transportation fuels – the lower three fuels shown – especially in California.

Figure 6 sums these electricity and fuel use projections across the three states, and translates them into GHG emissions. As shown, three transportation fuels – gasoline, diesel, and jet fuel – comprise over half of all emissions through 2020, growing in share from 52% to 55% largely due

[8] www.seib.org/leap

[9] The public goods charges are not guaranteed to continue through 2020. For instance, Oregon's Energy Trust is currently scheduled to sunset in 2012. However, we assume continuation for consistency of the base case projection.

to increased air travel. Direct use of fossil fuels in buildings and industry, largely natural gas with some oil product use in industry (and a small amount of coal), accounts for slightly over 20% of emissions through this period.

Electricity generation accounts for the remaining energy-related emissions, about one quarter of the total. As noted above, and as detailed in Appendices A and B, we include the emissions from imported electricity. As a result, the fraction of electricity coming from coal increases, because of growing imports from coal plants in the interior West. The West Coast states still consume more electricity from natural gas than from coal, at least through 2010. However, as shown in Figure 7, throughout the 2000-2020 period, more of the region's electricity *emissions* are expected to come from coal, since emissions per MWh from coal are about twice as high as for gas.

1.3 Cost analysis approach

Our analysis considers the direct costs associated with incremental technology investments, fuel provision, and, in some cases, program implementation.[10] For an electricity efficiency measure, for example, we consider the annualized incremental costs of the more efficient technology and compare these against the annualized benefits of avoiding marginal sources of electricity generation[11], transmission, and distribution. For alternative vehicle fuels, i.e. blending of biodiesel and cellulosic ethanol in diesel and gasoline stocks, respectively, we simply calculate the difference between projected prices of alternative and conventional fuels. In the case of light-duty vehicle GHG emissions standards, where analysis is particularly complex, we do not conduct our own analysis, and instead estimates directly from the recently released CARB analysis of the California AB 1493 (Pavley) as a lower bound on expected economic benefits.[12]

As with all such cost assessments, results are driven by assumptions of future costs. The key assumptions, including natural gas and petroleum product prices and the costs of acquiring renewable resources, are described in the Appendix C below. To provide a consistent set of price projections, we drew most of our projections from USDOE's Annual Energy Outlook (2004) and from Tellus' in-house version of the US Department of Energy's National Energy Modeling System (NEMS). These may differ somewhat from state and regional projections prepared by other agencies. The major uncertainties surrounding natural gas and other prices (which average around $5/MMBtu here) may call for sensitivity analysis.

[10] Program development costs are folded into energy efficiency program costs. However, they are not included for other measures where such estimates are not readily available (e.g. VMT reduction, administration of utility carbon policy, etc.)
[11] Avoided generation sources consist primarily of new coal and natural gas facilities spread across the West, along with some existing higher cost generating resources, and some new geothermal and wind renewable sources, as indicated by NEMS modeling runs.
[12] June 14, 2004 Draft, California Environmental Protection Agency Air Resources Board, Staff Proposal Regarding the Maximum Feasible and Cost-Effective Reduction of Greenhouse Gas Emissions from Motor Vehicles.

Table 7. Data sources used for historical and base case projected emissions

	Historical GHG emissions	**Fuel and electricity use projections**	**Consumption-based electricity Accounting**
California	CEC (2002)[13]	Electricity and natural gas from CEC 2003.[14] Gasoline, diesel and jet fuel from CEC 2003b.[15] The current California RPS (20% by 2017) is also reflected in this projection.	- LBNL report[16] - Gross System Fuel Mix for 2002[17] - CEC electricity generation report (1990-2001)[18]
Oregon	Oregon Office of Energy	Growth in electricity demand from NW Power Council 5th Plan Medium Forecast[19]. Other fuels from US DOE Annual Energy Outlook 2004[20], allocated to state by expected population and economic growth.	Data provided by OR OOE[21]
Washington	WA CTED		WA CTED Fuel Mix Disclosure Reports[22]
Supplemental Data (where needed)	EIA State Energy Data Report	Marginal electricity sources based on NEMS output for mix of incremental generation sources in western region, 2005-2020.	

[13] California Energy Commission, 2002. Inventory *of California Greenhouse Gas Emissions and Sinks: 1990-1999.* http://www.energy.ca.gov/reports/600-02-001F Report #: 600-02-001F

[14] California Energy Commission, 2003. *Electricity and Natural Gas Assessment Report.* http://www.energy.ca.gov/reports/100-03-014F.PDF Report #: 100-03-014F and California Energy Commission, 2003.California Energy Demand 2003-2013 Forecast, August. http://www.energy.ca.gov/reports/2003-08-08_100-03-002.PDF

[15] California Energy Commission, 2003b. *Appendix B: Base Case Forecast of California Transportation Energy Demand (Task 2).* http://www.energy.ca.gov/fuels/petroleum_dependence/documents/2003-10-28_600-03-005A2.PDF Report: P600-03-005A2

[16] Marnay, C. et al, 2002. *Estimating Carbon Dioxide Emissions Factors for the California Electric Power Sector,* August 2002, Energy Analysis Department, Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, LBNL-49945

[17] http://www.energy.ca.gov/reports/2003-04-21_300-03-002.PDF

[18] http://www.energy.ca.gov/electricity/electricity_generation.html

[19] http://www.nwcouncil.org/library/2003/2003-6.htm

[20] Energy Information Administration (EIA), 2004. *Annual Energy Outlook 2004.* http://www.eia.doe.gov/oiaf/aeo/

[21] Spreadsheet entitled net-mix-2002.xls.

[22] http://www.cted.wa.gov/DesktopDefault.aspx?TabId=73

Figure 4. Energy-Related GHG Emissions by Sector and by State, 1990-2020

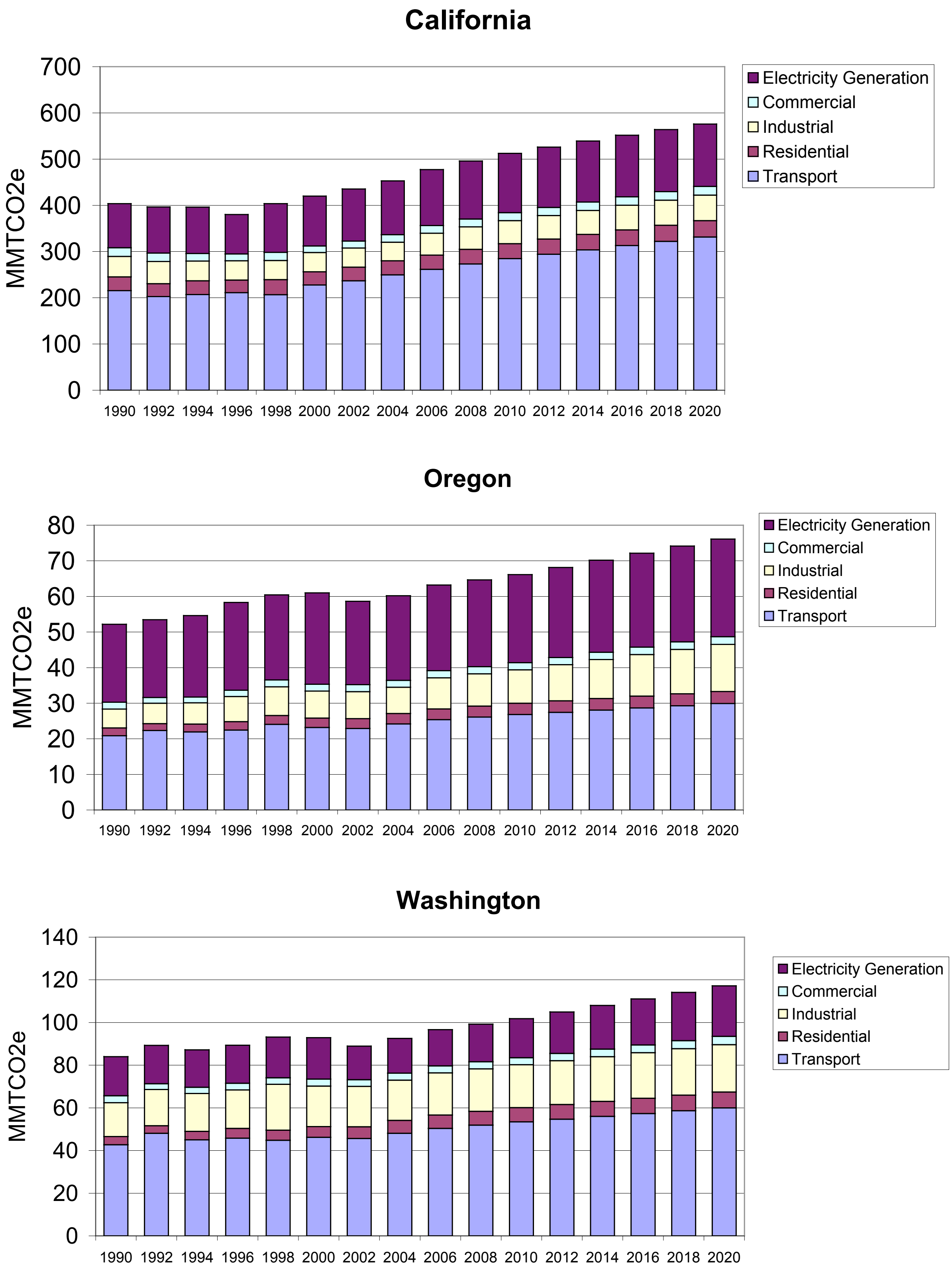
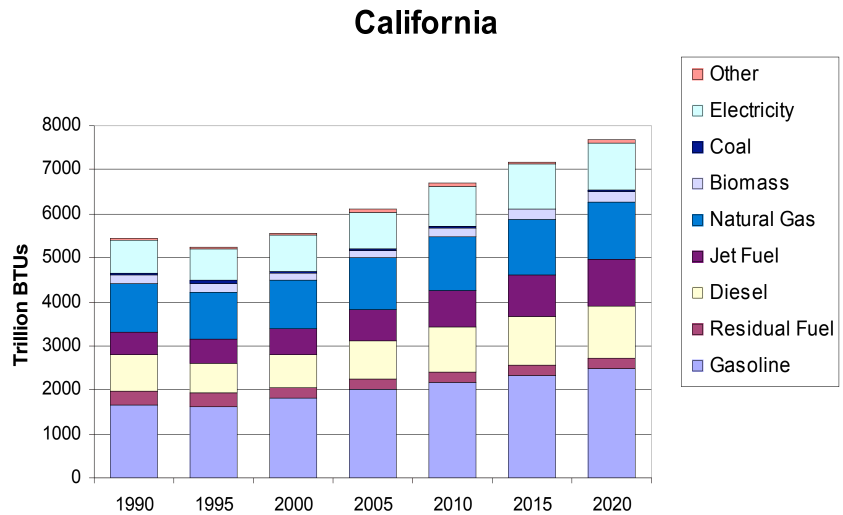
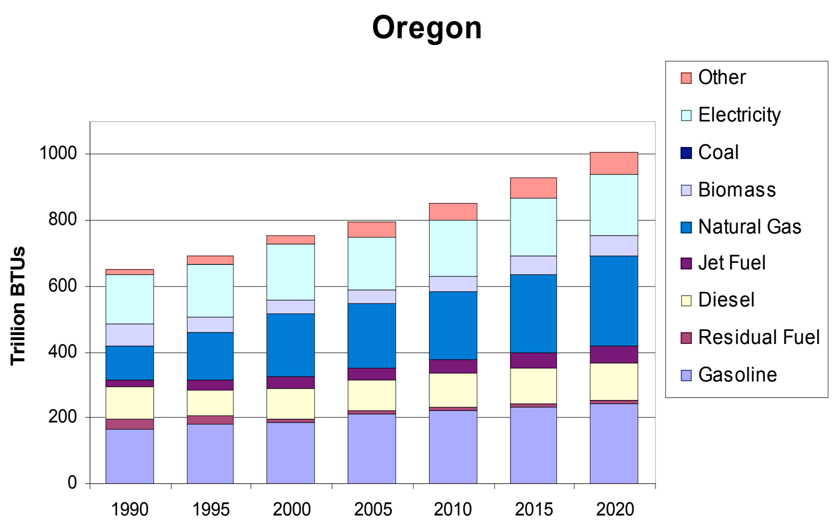


Figure 5. Final energy use by state 1990-2020





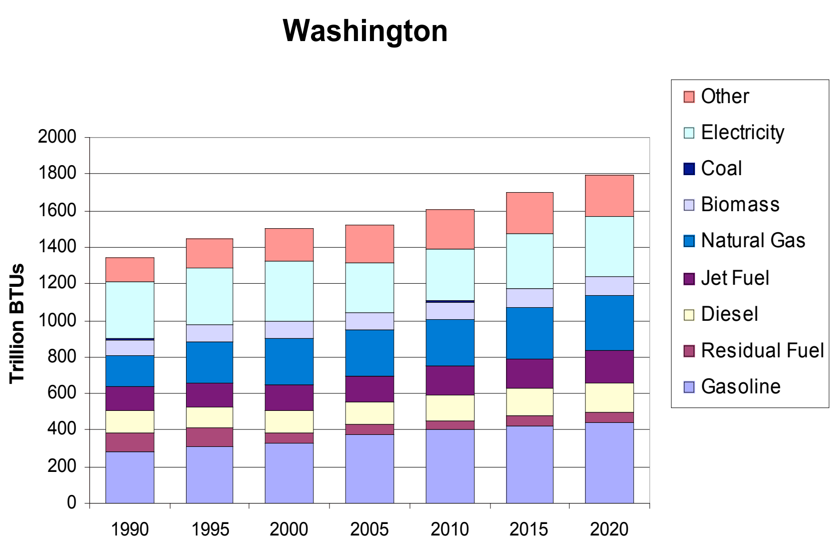


Figure 6. Energy-related CO2 Emissions by final fuel, 1990-2020, 3 states combined

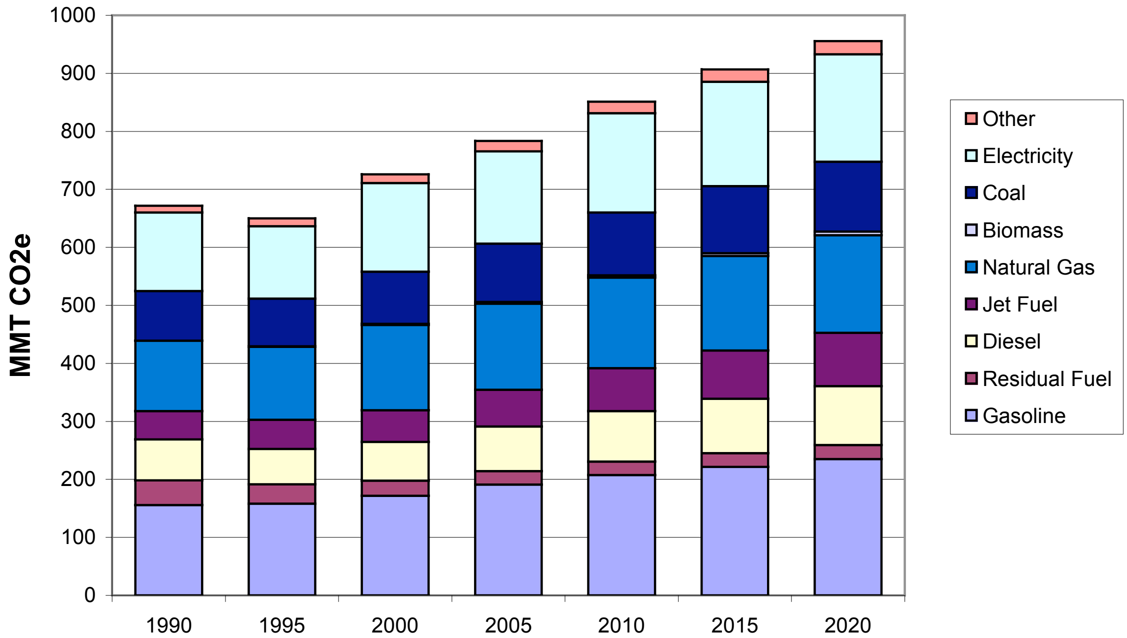
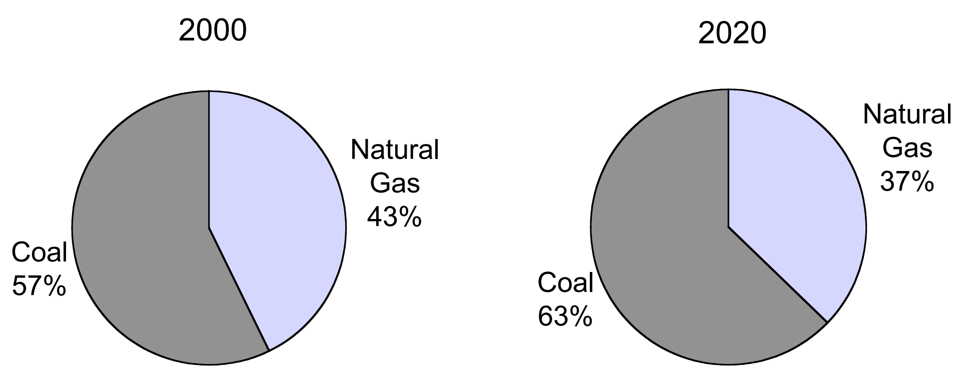


Figure 7. Source of Electric Generation GHG Emissions (in *electricity* bar of Figure 6), 3 states combined



2. Buildings and Industry Strategies

After transportation, buildings and industry are the next leading source of current and projected GHG emissions across the three states. Direct emissions from on-site fossil fuel combustion currently account for slightly over 20% of energy-related carbon dioxide emissions. However, the buildings and industry fraction increases to nearly half of energy-related CO2 emissions when the consumption of electricity and the fuel burned to produce it are considered.

Numerous studies demonstrate the large potential for reducing emissions through the purchase and proper maintenance of more energy-efficient equipment – equipment that is on the market and readily available today – as well as the construction and renovation of high-efficiency "green" buildings.[23] Industrial processes can be optimized to limit fossil fuel use, as well as the emissions of other greenhouse gases. Industrial and commercial buildings with significant and suitable heat loads may also be able to achieve greater efficiencies and lower overall GHG emissions through combined heat and power (CHP) systems.

In the sections below, we analyze four strategies aimed at capturing these gains: codes and standards, efficiency programs, industrial emissions policy, and combined heat and power initiatives.

2.1 Codes and Standards

Appliance efficiency standards can be implemented at the state level for appliances not covered by federal standards. State appliance standards are among the strategies included in the September 2003 West Coast Governors' Global Warming agreement. As the Codes and Standards Working Group formed by the Governors' Initiative noted in their April 2004 draft report, "minimum standards are the least-cost way for states to insure cost effective improvement of the energy efficiency of buildings and the equipment and appliances used in buildings."

Our analysis considers the emissions and economic benefits of standards for the 18 appliances listed in Table 18 below. It is adapted from detailed assessment by the American Council for an Energy Efficient Economy.[24] In California, several of these products such as commercial washing machines are covered by recently adopted standards, and are thus excluded from the California analysis. The California Energy Commission is currently developing additional standards for most of the others appliances shown in Table 18. Since the CEC is also looking at several products not considered in this analysis, such as pool pumps, our estimates are likely to underestimate the total savings. Several other states around the US are in the process of adopting appliance standards[25], and the Department of Community, Trade, and Economic Development is

---

[23] Although not considered here so-called "green buildings" could achieve further GHG reductions through choice of building products, transit-oriented locations, or maintenance of trees and open space. Analyses were not readily available on estimates of GHG reductions due to these other options.

[24] Draft analysis, Steve Nadel, ACEEE. We adapted the economic analysis to reflect regional avoided electricity costs, assumed to be about $39.1/MWh on levelized basis for delivered electricity, based on NW Power Planning Council Aurora modeling runs for the full Western grid. California avoided costs are typically higher than this level, thus this estimate may significantly understate economic benefits to California and the region.

[25] For more information on candidate appliances and the status of other state efforts, see www.standardsasap.org.

currently drafting proposed standards legislation for consideration in Washington, which is likely to include most of these products.[26]

Appliance standards, as modeled here and shown in Table 8, would yield over 7000 GWh in electricity savings in 2020 (2% of projected base case electricity use), nearly 13 trillion BTU of natural gas (1% of projected buildings and industry gas use), as well as nearly 300 million gallons of water supply annually. Standards are a relatively low-cost means to improve efficiency, as they do not require financial incentives or utility programs. Across the three states, the net cost savings -- avoided electricity supply costs minus the incremental cost of more efficiency appliances – come to $0.8 billion in 2020, and add up to $3.6 billion in cumulative present value terms from 2006 to 2020 across the three states. Actual benefits could well be higher, since we did not include the appliances that are being considered in California only. These savings would accrue across residential and consumer bills for electricity and gas, as well as in some commercial water bills (for establishments with washers and pre-rinse spray valves).

Table 8. Appliance Standards: Estimated Energy and Cost Savings in 2020

	CA	OR	WA	Region
Electricity Savings (GWh)	4,809	887	1,432	**7,128**
Gas Savings (Trillion BTU)	9.5	1.3	2.1	**12.9**
Water Savings (Million Gallons)	220	23	40	**283**
Cost Savings in 2020 ($million)	$0.5	$0.1	$0.2	**$0.8**
NPV (to 2020, $million)	$2.5	$0.3	$0.8	**$3.6**

With respect to building codes, another WCG WGI priority area, we only considered the non-residential code upgrade in Washington that is currently being evaluated by the state's Building Code Council. This code upgrade has been estimated to yield approximately 10% savings in new buildings, which we incorporate in our analysis.[27] Other code improvements across the three states are certainly possible, and could provide an important means to improve building practices as technologies evolve over time. However, we did not have sufficient information upon which to evaluate these.

2.2 Energy Efficiency Programs – Tapping the Full Potential

Many West Coast utilities are recognized leaders in energy efficiency. Several significant regional and state-level programs and initiatives provide support and continuity to energy efficiency efforts. These include, among others, the public benefit fund activities administered in California and Oregon, tax credits for efficient building construction, and market transformation programs such as those implemented by the Northwest Energy Efficiency Alliance.

Nonetheless, recent studies across the region continue to show the potential for significant increases in efficiency program activity and in resulting energy savings. These studies include, the ongoing Northwest Power Planning Council 5th Plan conservation assessment, energy efficiency market potential studies conducted by KEMA-XENERGY for the CEC and California

[26] Excluding those with longer paybacks.
[27] Pending forthcoming analysis by Ecotope for WA CTED.

investor-owned utilities, and gas conservation assessments conducted by KEMA-XENERGY and Ecotope for Puget Sound Energy and the Oregon Energy Trust, respectively.[28]

Based on these studies, we derived a set of state-wide energy efficiency reduction potentials, as shown in Table 9.[29] Because codes and standards are likely to target some of the same appliances identified in these studies, we reduced the estimates of savings potentials where relevant.[30] We also reduced these estimates, in some cases by more than half, to reflect efficiency savings expected under base case scenario. Both California and Oregon have public benefit charges in place that should continue to fund a significant amount of ongoing efficiency gains. Despite the fact that Washington currently lacks a statewide policy to support a significant amount of conservation activity on a consistent basis, utilities have a strong track record in this area. Thus we included some of the overall efficiency potential in the base case for Washington as well.[31]

The variation in incremental reduction potentials by state, sector, and fuel – from a low of 2% for industrial electricity in Oregon to 14% for residential electricity in California and commercial electricity in the Northwest – reflects a mix of existing policies (e.g. public benefit funds in CA and OR), complementary strategies (e.g. appliance standards), local conditions, as well as study approaches.[32]

Achieving these potentials will require increased and sustained investment in efficiency programs and activities. This, in turn, could be achieved through existing instruments, such as the California public goods charge or the Oregon Energy Trust funds, which may require increased levels of funding. Washington currently lacks a similar mechanism to ensure high and sustained levels of funding for efficiency activity.

Alternatively, or in combination with public goods charges, utilities could increase energy efficiency as part of their overall portfolio of resources. An example of this is the 2004 decision by the California PUC to increase energy efficiency investment by investor owned utilities. States also have the option of pursuing greater natural gas end use efficiency through public utility regulation.

---

[28] KEMA-XENERGY, *California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study*, Fred Coito and Mike Rufo, for PG&E, July 2003. *California Statewide Residential Sector Energy Efficiency Potential Study*, Fred Coito and Mike Rufo, KEMA-XENERGY, for PG&E, April 2003. *California Statewide Commercial Sector Energy Efficiency Potential Study*, Fred Coito and Mike Rufo, KEMA-XENERGY, for PG&E, July 9, 2002. *California Industrial Market Characterization Study*, XENERGY, for PG&E, December 2001.

[29] The California studies project savings for only 10 years. To project for 15 years, we increase these estimates by 25%, given that longer-lived equipment and buildings continue to accrue savings, and new, more efficient technologies are likely to emerge.

[30] We deducted 50% of code and appliance efficiency standard savings from the overall efficiency program savings.

[31] We have thus assumed that Washington will achieve about half of the estimated savings as Oregon. The Oregon estimated is based roughly on the Energy Trust of Oregon goal of 300aMW by 2012. For California, the base case efficiency activity is based on estimates found in the KEMA-XENERGY studies noted above. It is assumed that these levels of efficiency savings roughly match the efficiency assumptions used in the CEC electricity and natural gas forecasts, which we use here.

[32] In some cases, studies only projected savings out for 10 years.

Table 9. Incremental Achievable Efficiency Savings Potential
(above base case efficiency program levels and savings from codes and standards)
(cumulative savings as % of that years' demand)

Residential Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	5%	11%	2%	4%
Oregon	2%	6%	2%	5%
Washington	3%	9%	3%	7%

Commercial Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	3%	5%	3%	8%
Oregon	3%	7%	1%	3%
Washington	4%	11%	2%	6%

Industrial Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	6%	12%	7%	14%
Oregon	1%	2%	4%	9%
Washington	1%	4%	2%	5%

These energy savings are likely to provide consumers and businesses with major economic benefits. The achievable efficiency potential identified by the studies used here only included measures that were found to be cost-effective.

If achieved, these efficiency gains would yield $2 billion in overall cost savings by 2020, and a cumulative $10 billion by that time. These savings represent avoided costs of electricity generation and delivery minus the incremental costs of the efficiency equipment and programs. (See Appendix C for a discussion of the cost assumptions.)

2.3 Industrial Carbon Emissions Policy

While electricity and natural gas use account for the lion's share (over 95%) of residential and commercial sector GHG emissions, much of this is emitted upstream at the source of electricity generation. By contrast, the industrial sector emits 60% of its GHG emissions onsite, from oil and coal (37%), as well as natural gas use (23%). Refineries, chemical facilities, and cement manufacturer are among the major direct fossil fuel consumers in the industrial sector.

Studies suggest that many industries have significant opportunities for cost-effective fuel savings. In particular, an ACEEE study showed that industries nationally could save money while reducing oil use by 14%, gas use by 11%, and coal use by 29% over 15 years, through a range of initiatives to motivate and assist industries to identify and exploit energy efficiency opportunities.[33]

Though most industrial facilities have clear incentives to reduce fuel costs, fuel-saving measures must compete for attention and resources with other bottom-line concerns. Where management has made energy and emissions reductions a clear goal, manufacturers have been able to make major strides. For example, Lafarge, the world's largest cement manufacturer, has committed to reduce greenhouse gas emissions 10 percent below 1990 levels by 2010. Polaroid has made the commitment to reduce CO2 emissions 25 percent below 1994 levels by the year 2010. And the Silicon Valley Manufacturers Group including Hewlett-Packard, Oracle, Calpine, Lockheed, ALZA, Life Scan and PG&E, along with the city of San Jose, NASA Ames Research Center and the Santa Clara Valley Water District, have set a goal of cutting Santa Clara County's carbon dioxide emissions to 20 percent below 1990 levels by 2010.

The West Coast Governors may wish to consider flexible policies to address the large untapped potential for reducing direct fuel use in industry. At the national level, the proposed Climate Stewardship Act would include most (larger) industrial GHG emitters (all entities that emit over 10,000 metric tons of carbon-equivalent emissions a year) along with electricity producers in an overall emissions cap system. If West Coast states were to adopt an electricity emissions cap and trade system, larger industrial emitters could be included as well. The Northeastern states' Regional Greenhouse Gas Initiative will also eventually consider inclusion of industrial carbon sources in its cap and trade system.

For this analysis, we considered the cost-effective industrial fuel use reductions as identified in the ACEEE study note above[34], on the assumption that an industrial carbon emissions policy, such as cap and trade, could be designed to capture them. The fuel cost savings are likely to exceed the added equipment and other costs to the tune of nearly $2 billion cumulatively from 2005 to 2020.

Though these reduction estimates are based on national aggregate data, we used them due to the lack of industrial fuel use studies in the region. Further investigation of industrial fuel use patterns would help to better tailor fuel use reduction potentials to the unique mix of industries found in California and the Northwest.

2.4 Combined Heat and Power

From half to two-thirds of the energy used for fuel-based electricity generation is typically lost as waste heat. Combined heat and power (CHP) systems effectively capture this waste heat and supply it to a facility's process or building heat requirements, and can thereby approximately double the overall efficiency of fuel use to around 80 percent. CHP systems can be as large as standard power plants, as is often the case for major industries and district heating systems, or small enough for modest-sized buildings and restaurants. They are typically optimized for either

[33] American Council for an Energy Efficient Economy (ACEEE) study, *Smart Energy Policies: Savings Money and Reducing Pollutant Emissions through Greater Energy Efficiency* (Nadel and Geller 2001).

[34] We subtracted the industrial gas efficiency potentials for each state shown in the previous sector from the 11% gas reductions by 2020 estimated from the ACEEE analysis. In the case of California, therefore, no additional gas savings were assumed from the industrial strategy.

electricity generation or for heat delivery, depending on the heat demands of the particular facility. CHP is a well-established technology, particularly in larger industries, and is in place in much of the region's refineries and paper and pulp mills. However, they are less ubiquitous in small industries and commercial establishments.

The West Coast states could support increased development of CHP through a number of mechanisms including establishment of interconnection standards, appropriate tariff structures, output-based environmental regulations that reward efficiency benefits, tax credits/exemptions, accelerated depreciation, inclusion of CHP in portfolio standards, incentives directed through public benefit funds, and exemption from exit fees that are not directly related to service to the customer. States could work with the Pacific Northwest CHP Initiative or other regional entities to help identify the most effective strategies to move forward.

Assessing the impact of these barrier removal and incentive policies is challenging, since these mechanisms would need to be more specifically defined, and the response is often difficult to judge. To get a rough sense of overall achievable CHP potential, we assume a concerted effort with significant barrier reductions and/or incentives as reflected in two CHP market potential studies[35], and applied some judgment to limit the total potentials of achievable by 2020 to a fraction of that indicated in the studies. These estimates are shown in Table 10, and the technical assumptions underlying our analysis of emissions reduction potential are shown in Appendix D.

Table 10. CHP Potentials Identified, by state (MW_{elec} in year 2020)

	CA	OR	WA
New Commercial CHP	1015	219	392
New Industrial CHP	1984	869	1,010

The net emissions savings of CHP measures – avoided electricity emissions minus added natural gas emission -- total 7 MMtCO2 in 2010 and 18 MMtCO2 in 2020, a 10% reduction in overall electricity emissions relative to base case levels in 2020. Thus CHP presents a promising avenue for pursuing regional emissions reductions.

Based on a comparison of the net costs of electricity generated by CHP units ($42 to $48 per MWh) to avoided electricity costs ($43 to $57 per MWh), there is a significant cost savings potential as well, perhaps totaling $2.5 billion NPV through 2020 (See Appendix C).[36] The challenge lies in overcoming the many barriers to successful expansion of CHP activity.

[35] *Technical Market Potential for CHP in the Pacific Northwest*, Subtask 1-2 Deliverable, Energy International Report No. 02-1101-BR0023 for Oak Ridge National Laboratory, July 25, 2003. Onsite Sycom Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector*, and *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, both prepared for the USDOE EIA, January, 2000.

[36] We assume that CHP units avoided about the costs of transmission service, given the proximity of CHP units to other electric loads. The costs of distribution (about 60% of the combined transmission and distribution costs) are included for CHP generation.

2.5 Combined Results

Together, these four strategies are estimated to reduce direct fuel use and electricity emissions by 28 MMTCO2e in 2010 and 69 MMTCO2e in 2020, reductions of 9% and 20% respectively from base case projections, as shown in Table 11. Over half of these savings come from ramping up gas and electric efficiency programs. The fuller impact of these policies, particularly on electricity and natural gas emissions, is discussed further at the end of the Section 3 below.

Table 11. Emissions Reductions from Buildings and Industry Strategies, all 3 states (MMTCO2e)

	2010	**2020**
Codes and Standards	2	5
Efficiency Programs	16	37
Industry Carbon Policy	3	9
Combined Heat and Power*	7	18
Total	28	69
Reduction relative to base case	*9%*	*20%*

** These savings are net of the added natural gas consumption at CHP facilities.*

3. Electricity Supply Strategies

In 2000, the fossil fuels used to generate electricity for California, Oregon, and Washington consumers produced roughly 27% of the region's energy-related GHG emissions. This fraction is expected to remain fairly steady through 2020 under the base case scenario. This share is smaller than the US average (38% of energy-related emissions[37]) due to the regional abundance of hydro resources, especially in the Northwest, and greater local reliance on gas rather than coal, the predominant fuel for electricity generated throughout the US.

However, West Coast states also import a significant amount of coal-based electricity from the interior West. Utilities across the three states, especially in Oregon and California, own or contract for coal resources located in the region stretching from Montana to the Four Corners area. As a result, the amount of coal-based electricity ascribed to California, Oregon, and Washington, as shown in the left hand set of charts in Figure 11 below, is far higher than what one might expect considering the relative scarcity of coal plants on the West Coast.

As noted in Section 1, our analysis uses a consumption-based approach to electricity accounting, i.e. one that calculates emissions based on the sources of electricity used to meet in-state electricity demands regardless of where they are located. It differs from the typical state-level inventory methods, which count only the emissions of power plants located within state boundaries. Those familiar with state inventories might therefore be surprised at the higher emissions for electricity reported here. However, this consumption-based approach is increasingly being used in region for greenhouse gas analysis, since it can better assess the real impacts of electric sector policies on overall emissions. (See Appendix B for further discussion)

While there are several potential strategies to address electricity emissions, we consider two broad ones here: increasing renewable generation and decreasing the carbon content of delivered electricity via a carbon cap-and-trade or other electricity carbon policy.

3.1 Renewable Portfolio Standard (RPS)

Renewable Portfolio Standards (RPS) provide a flexible, market-oriented approach for accelerating the adoption of low-carbon, renewable electricity sources. An RPS sets a schedule of targets specifying the percentage of retail electricity sales that electricity providers must deliver from qualifying renewable resources, either directly or through the purchase of renewable energy credits.

RPS policies are currently in place in 13 states, California among them (though implementation details are currently being finalized). In Washington, legislation containing an RPS was considered by the legislature in 2003, but did not pass out of committee. In Oregon, renewables are currently supported by a public benefit charge as well as tax incentives. California also has a similar renewables fund, collected from ratepayers, and directed to a variety of existing, new, and emerging technologies. These programs actively nurture a number of renewable technology markets, including solar photovoltaic and water heating systems. However, they are not designed to ensure the levels of renewable electricity typically targeted through an RPS.

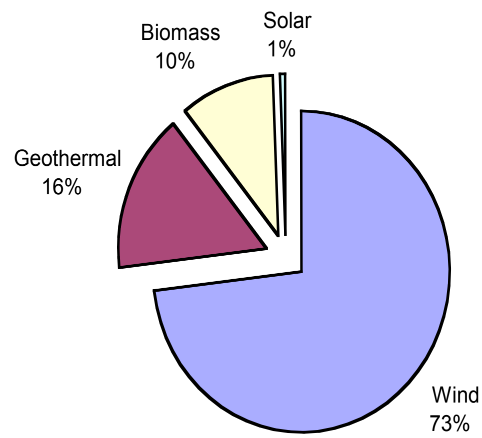
[37] Based on US DOE EIA figures for the year 2000.

For this analysis, we considered the following coordinated RPS strategy[38]:

- California increases its current RPS target (20% in 2017) to 20% by 2010, and 33% by 2020, as recently recommended by Gov. Schwarzenegger.[39]
- Oregon and Washington reach a 20% RPS target by 2020. These targets are only slightly less ambitious than the recommended California goal, given the current higher level (nearly 10% vs. 1% in OR and WA) and the current definition of qualifying renewables in the California market.
- Qualifying resources would likely include wind, solar, geothermal, biomass, landfill gas, and small-scale hydro.[40] As shown in Figure 8, our NEMS-based modeling analysis indicates that about three-fourths of new renewable electricity supplies would come from wind, and about 17% and 7% from biomass and geothermal resources, respectively.

Joint implementation of an RPS across three states could offer several advantages including consistency of market signals to electricity providers, lower administrative costs, and better tracking of renewable resources and credits.

Figure 8. Average regional mix of new renewables acquired under an RPS (% of generation)



Our modeling of the RPS strategy indicates that it could reduce the three states' emissions by 16 MMtCO2 in 2010 and by 34 MMtCO2 in 2020. By reducing the need for new fossil fueled power plants, and reducing generation or accelerating retirement of existing ones, the RPS strategy could reduce base case electricity-related emissions projected for 2020 by 18%.

The cost impact of an RPS to West Coast electricity consumers will depend on a number of uncertain factors, including the fate of the federal production tax (PTC) credit[41] for renewable energy, the future costs and performance of renewable energy technologies, the costs of

[38] The West Coast Governors' WGI Renewable Resources working group, in its April draft, recommended the development of a "set of strategies and incentives that will achieve 20 percent of retail energy sales from renewable resources in the western states by 2017." They did not point specifically to coordinated RPS systems, but rather to "encourage the Western Interconnection to place grid expansion investment priority where it supports development of renewable resources, and develop policies on transmission access and pricing that address avoided costs and benefits of renewable resources."

[39] Governor Arnold Schwarzenegger's Action Plan for California's Environment, Final Draft, November 9, 2003.

[40] The California RPS includes most existing geothermal and small hydro resources. To be consistent, we included these resources in calculating new resources need to meet California's 33% target. However, we did not attempt to define or include "small hydro" in Oregon and Washington.

[41] The PTC has until recently provided a credit of approximately 1.8 cents/kW/h over the first 10 years of operation for wind and some biomass applications. However, the PTC was suspended when Congress failed to reauthorize it last year. This analysis assumes the PTC is not extended beyond its current specification (credit only applies to plants built prior to 2004).

generation from fossil fuel sources, and the added transmission, capacity, and shaping costs associated with intermittent resources, such as wind.[42] Based on our NEMS modeling runs, we find that an RPS strategy as configured here would deliver a slight, overall savings in regional electricity supply costs of around $0.5 billion from 2005 to 2020. (See Appendix C for detailed cost assumptions) Given the disparities among states in the avoided costs of electricity supply, the RPS shows a net gain in California, roughly breakeven cost in Oregon, and a net cost in Washington. (See Table 5)

3.2 Electricity Carbon Policy

A direct carbon policy would tap all options available to reduce carbon emissions, including more efficient fossil fueled generation (high efficiency combined cycle plants or fuel cells), shifting from coal to gas, capture and storage of power plant CO2 emissions, and further penetration of renewable energy, CHP, and demand-side efficiency.

A carbon policy could take many alternative forms – a cap-and-trade system, a carbon content standard (also know as Emission Portfolio Standard, as described in the footnote below), or a carbon benefit fund (akin to a public benefit fund but assessed on carbon emissions), among others. A number of factors influence which options would make most sense in the West Coast, such as:

- The heterogeneity of electricity sources in the West. The coal-reliant interior West is a major source of incremental electricity generation for California, Oregon, and Washington. An effective carbon policy, if implemented only among the three states, should provide effective disincentives to importing coal-based electricity, or otherwise shifting emissions to other states.[43]
- Implementation ability (tracking, etc.)
- Economic efficiency
- Political feasibility

Evaluation of these factors and the most appropriate carbon policy is beyond the scope of this exercise. Nonetheless, all of these policies are likely to have a common thread – they would send a strong market signal by placing a liability on the construction of, or generation from, fossil fuel plants.

---

[42] The costs and benefits of an RPS would be subject to other uncertainties such as the extent of complementary activities in interior West states (affecting demand for, and availability of, renewable resources). Added transmission and capacity costs are built into our NEMS model runs and cost analysis.

[43] One of the major challenges of a utility cap-and-trade system is limiting "leakage", i.e. increases in emissions outside the trading system boundary that might partially offset reduced emissions within. This issue is of particular concern in the West Coast, where electricity imports from coal-rich Interior West states are typically associated with significantly higher emissions. For example, if not properly designed, might fail to achieve an overall reduction in emissions from power plants serving the three West Coast States. It may therefore be important to consider including an *emissions portfolio standard*, which reflects the emissions of all generating resources used to meet demands, rather than merely the emissions of resources located within the region, as well as *electricity source tracking systems* that can help to ensure that the sources of imported electricity are accurately identified.

For this analysis, we applied the NEMS model to simulate a West-wide (WECC)[44] carbon cap and allowance trading system (See Appendix A).[45] Specifically, we modeled a scenario in which permit prices reach \$20/tCO2 in 2020 across the WECC region; this approach reveals the carbon emissions limits or targets that would yield this carbon permit trading price.[46] Ideally, we would model the three West Coast states, along with any other states that might seriously contemplate joining, in a common carbon strategy and then examine the interactions with the rest of the system. However that type of modeling requires far greater time and resources than we have at our disposal. Under the Regional Greenhouse Gas Initiative, the East Coast states have agreed to pursue a cap-and-trade system, and just beginning such a modeling exercise to inform policy design.

Though our West-wide approach is imperfect, it does help to reflect the disincentives for coal, and to a lesser extent, for natural gas generation that a West Coast carbon policy would create throughout the full Western region. This signal might be transmitted through the broader market signals that West Coast action would create, or through emissions portfolio standards that would penalize West Coast utilities that import carbon-emitting resources from other states. It also reflects what might result from wider participation in the cap and trade system across the West.

Our modeling analysis suggests that an electric sector carbon policy could achieve a 50% reduction in electricity-related GHG emissions by 2020 relative to 2000 levels, at permit price of \$20/tCO2 across the next 15 years, *if coupled with the efficiency, CHP, and RPS strategies.* If the other policies were not applied, the permit price (or other financial mechanism) required to achieve a 50% reduction would likely be far higher than shown here.[47] These complementary policies can provide important support to a sector-wide carbon policy, enabling it to achieve deeper reductions at a given marginal cost, and providing a diversity of levels to lower the carbon content of delivered electricity. As shown in Figure 9 below, the electric carbon policy adds another 20 MMtCO2 or 20% of the total reductions achieved by all of the electricity-related policies. If the West Coast states were to "go it alone", and without cooperation from other states or without effective leakage control mechanisms, the emissions reductions resulting from a carbon policy could be significantly lower than shown here.

Because it encourages switching from coal to higher-cost natural gas, and from older plants to new more energy-efficient plants, the electric sector carbon policy imposes costs, which might

[44]. The "Western region" modeled here corresponds to the US portion of the Western Electricity Coordinating Council stretching from the West Coast through to parts of Montana, Wyoming, Colorado, and New Mexico.
[45] Emissions cap and trade programs are well-established market-based instruments that aim to reduce emissions to a given level at the lowest cost. For example, the Clean Air Act of 1992 set up a cap-and-trade program for sulfur dioxide emissions, which is viewed by many as highly successful, meeting target emissions levels at far lower costs than originally expected. For CO2, a cap-and-trade program typically involves a) establishing a limit for state/regional power plant emissions, b) allocating emissions allowances, and c) enabling trading among participants, d) including other flexibility mechanisms (e.g. offsets); e) considering cost caps or other cost limitations; and f) dealing with leakage concerns (i.e. limiting any increase in emissions from power plants in states outside the program due to increased net electricity imports by states in the program).
[46] Models such as NEMS cannot directly model emissions caps at the regional level. One must instead model permit prices, which in turn indicates an associated level of emissions reductions.
[47] Focused energy efficiency programs are likely to achieve greater energy and GHG reductions than pure price signals, as might be transmitted by a carbon policy. Many residential and also commercial and industrial consumers are relatively insensitive to energy prices.

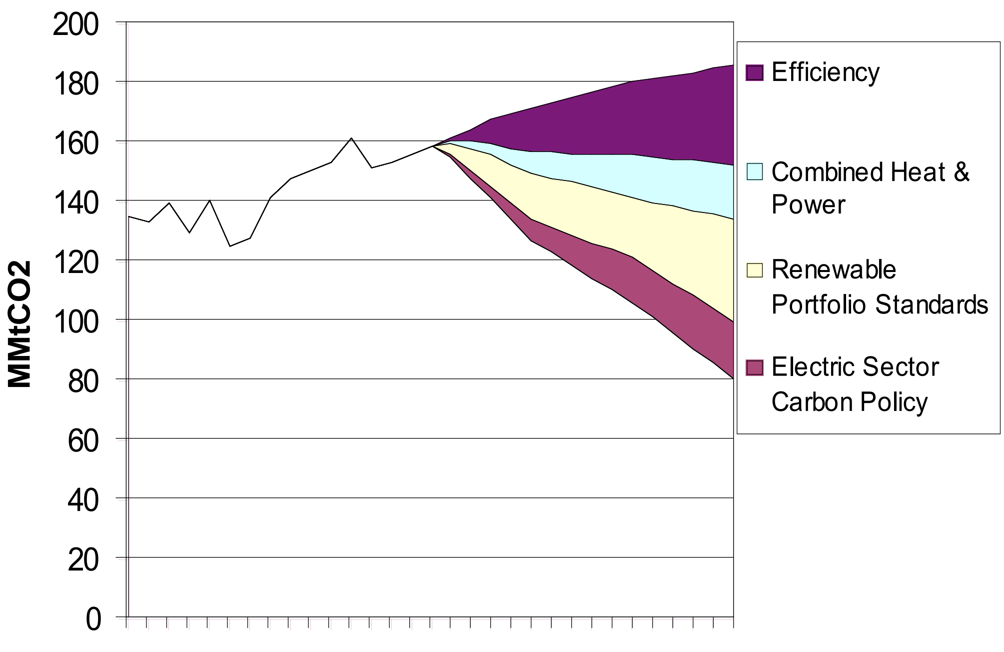
sum to about $3 billion cost in NPV terms by 2020. These costs, however, are likely to much smaller than the savings from efficiency strategies noted above. They are also small compared to the overall costs of generating electricity; they would add about 1% to total electricity supply costs.

3.3 Combined Results

Implementing both the RPS and utility carbon strategies described above leads to total emissions reductions of about 53 MMTCO2 in 2020, nearly one-quarter of base case electricity generation emissions (186 MMTCO2e). When further combined with the emissions reductions from efficiency programs, codes and standards, and combined heat and power, **this suite of demand and supply strategies appears capable of reducing electricity sector GHG emissions to about one-half of current levels**.

The overall GHG impact is illustrated in Figure 9 below. Through 2010, most of the reductions come from efficiency strategies (including codes and standards). Efficiency programs can more rapidly reach their full potential, given shorter lead times and technology lifetimes (on average), as compared with power supply investments. By 2020, efficiency and CHP strategies appear to achieve about half of the overall emission reductions (51 MMTCO2), with RPS and electricity carbon policy providing the other half.

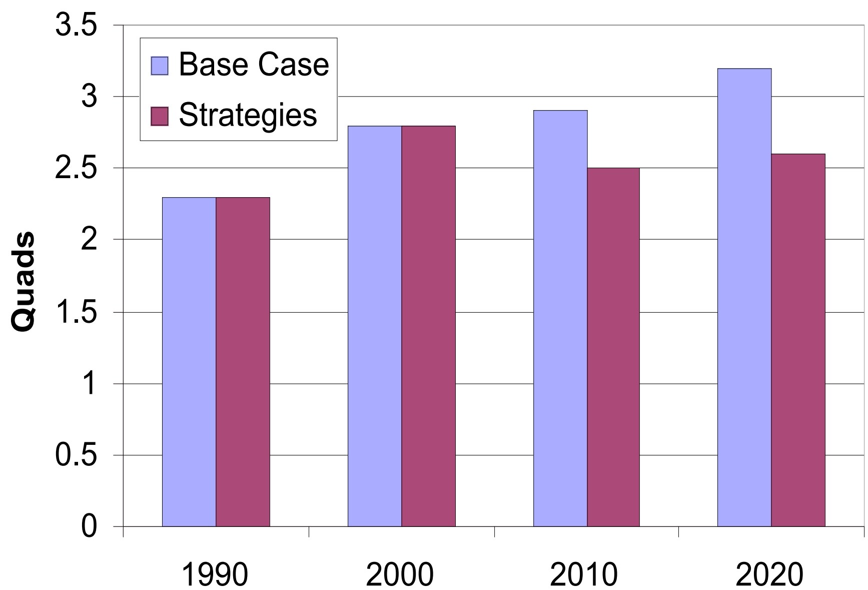
Figure 9. Electricity Emissions, all three states, after strategies



It is important, however, not to interpret these savings estimates *by strategy* too precisely. As noted previously, **these estimates should not be used to closely compare the relative benefits of individual strategies,** because implementing most individual strategies *in the absence of the other strategies* would increase the estimated benefits, in some cases quite dramatically. For instance, implementing the utility carbon policy (e.g. cap and trade) without the RPS, CHP, and efficiency strategies in place could more than double the emissions savings it would yield for the same target permit price (e.g. $20/tCO2).[48] While it aims to preserve consistency and avoid double counting of emissions benefits, **our approach understates the total emissions reductions that a cap and trade system or an RPS might yield on its own.**

To get a better picture of what these strategies mean in terms of the potential electricity supply mix, we show generation sources by state under both the base and strategy cases in Figure 11. We also show the effect of all six buildings, industry, and electricity strategies on natural gas use in Figure 10. While combined heat and power units will increase gas use in commercial and industrial establishments, and utility carbon policies might shift fuel choice from coal to gas, the overall effect is to *reduce* natural gas use by 19% in 2020 relative to base case levels. As indicated by a recent ACEEE report, **efficiency and renewable energy strategies, by reducing natural gas demands, could significantly reduce gas prices in the Pacific region.**[49]

Figure 10. Natural gas use 1990-2020, base case and after all strategies, all 3 states

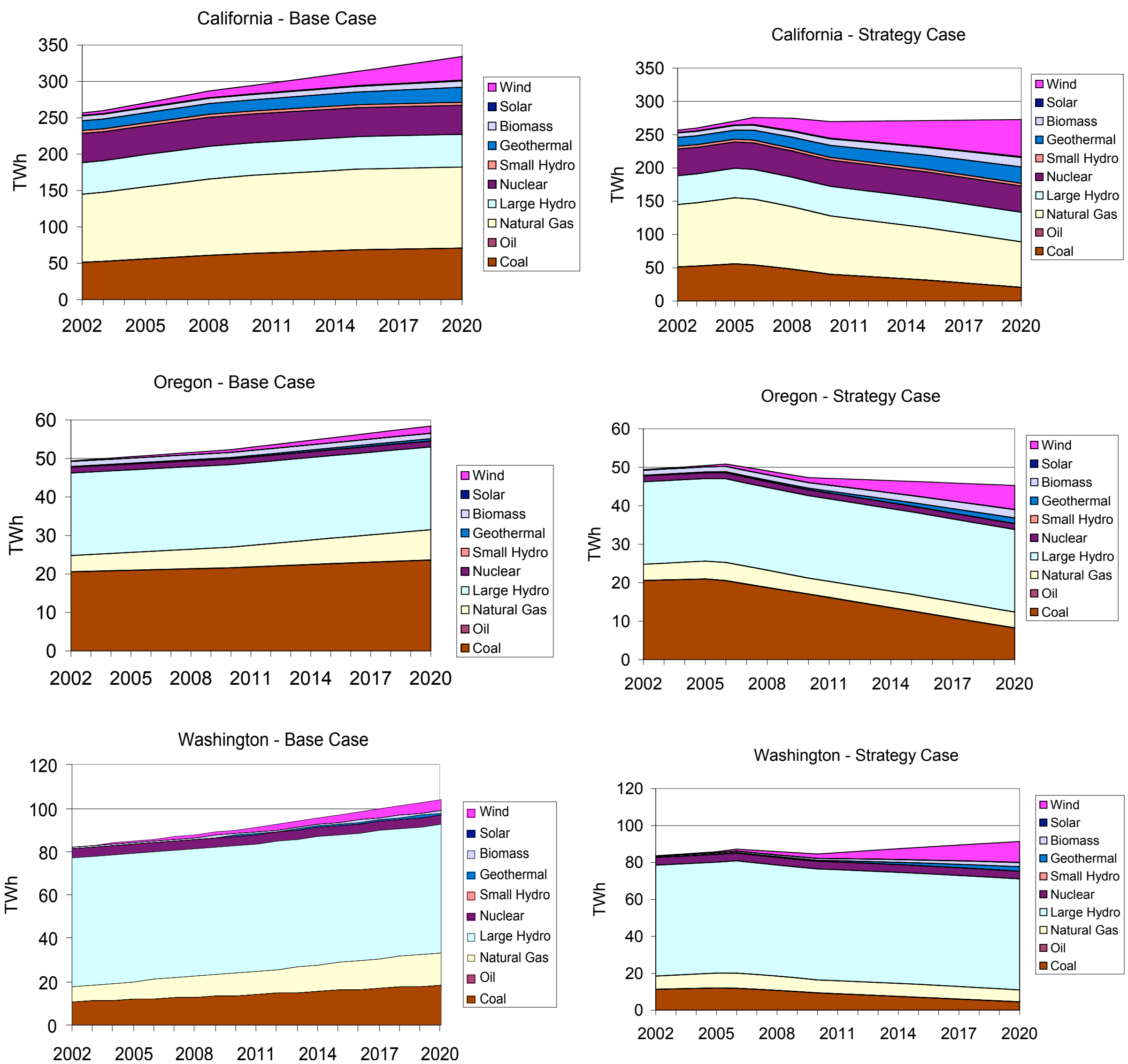


Finally, it is worth noting that reducing carbon emissions from electricity generation has important co-benefits, including reduced emissions of fine particulate matter, which is a known cause of respiratory ailments, and mercury, which is a powerful nervous system toxin and already contaminates over 50,000 lakes and streams in the US. A progressively more stringent carbon target also reduces demand for coal, and hence mining-related pollution of streams and degradation of landscapes and terrestrial habitats.

---

[48] Estimates based on preliminary work done for the Puget Sound CPAC process.
[49] Elliott, R. et al, 2003. *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*, American Council for an Energy-Efficient Economy, http://aceee.org/energy/efnatgas-study.htm. This suggests that energy efficiency and renewable energy strategies like those considered here d reduce wholesale natural gas prices by 20% by 2008 in West Coast states.

Figure 11. Comparison of Electricity Generation Mixes, Base Case vs. Strategy Case



4. Transportation Strategies

Transportation fuel use is the number one source of GHG emissions in all three West Coast states, and is likely to remain so well into the 21st century. Under the base case scenario described above, GHG emissions from transportation grow from 297 $MMTCO_2e$ in 2000 (52% of all energy-related emissions) to 421 $MMTCO_2e$ in 2020 (55%).

We examine four broad strategies aimed at reducing these emissions:

- light duty vehicles GHG emissions standards phased-in from 2009 onwards (patterned after the California's current AB 1493 "Pavley" effort through 2014, but not intended to precisely reflect the expected regulations);
- phasing in three alternative fuels starting in 2011: natural-gas-derived hydrogen in fuel-cell vehicles (2% of new light duty fleet by 2020), cellulosic ethanol (a 10% blend in all gasoline sold by 2020), and biodiesel (a 20% blend in all diesel sold by 2020);
- heavy duty vehicle GHG performance improvements starting in 2009; and
- a package of vehicle travel reduction policies, such as mass transit investments, enhanced smart growth policies, education and other related efforts.

These strategies not only lead to significant emissions reductions between now and 2020, but lay the groundwork to achieve deeper reductions in the future. This is especially true of light duty vehicle standards and vehicle travel reduction policies, where the impacts of technology development and changing growth patterns will be more pronounced after 2020.

We assume consistent implementation of these policies across all three states, although state circumstances and achievable reductions level may vary considerably. Vehicle mile travel (VMT) reduction policies are one obvious example; the ongoing growth management efforts across the three states will influence what can be accomplished over the next 15 years.[50]

It is important to note that this suite of policies does not cover one of the fastest growing sources of emissions growth: air travel. Under the base case scenario, GHG emissions from the use of jet fuel in the California alone are expected to increase from 55 $MMTCO_2e$ in 2000 to 92 $MMTCO_2e$ in 2020. Jet fuel could grow to comprise 16% of the California's 2020 GHG emissions. There are several potential options to address airport and jet fuel emissions, which have not been considered here.[51]

[50] As noted earlier, the goal of this analysis is to provide indicative rather than definitive results, and some policies such as VMT reduction are simply more difficult to assess given the difficulty in balancing long-range housing and business development plans with supportive or compatible transportation infrastructure.

[51] Options include the implementation of an emissions trading system, flight route optimization, early retirement of aircraft, and improvement of aerodynamics. See for example, Cames, M., Deuber, O., Rath, U., 2004. *Emissions Trading in International Civil Aviation,* Öko Institute, Berlin, and International Air Transport Association, 2001, *Emissions Trading for Aviation, Workstream 3: Key findings and conclusions,* Arthur Andersen.

4.1 Modeling Approach

To model the impacts of these four transportation strategies, we have relied on base year information relevant to the three-state region and combined this information where necessary with other sources. For light duty vehicles, we estimated the combined effect of the strategies on the total stock through stock turnover modeling. For heavy duty vehicles, given time and budget constraints, we made some simple estimates based on truck survival rates and new vehicle penetration levels. A summary of key assumptions is provided below.

- *New vehicle sales.* In California, we based our estimates of new LDV sales roughly on the CARB Pavley analysis.[52] In Oregon and Washington, we based our estimates on the Pacific region of the US Department of Energy's (DOE) Annual Energy Outlook for 2003 (AEO2003), scaled to Oregon and Washington on the basis of available base year and growth rate information.[53] For heavy duty vehicles (HDVs), we based our estimates for all three states on the Pacific region of the US Department of Energy's (DOE) Annual Energy Outlook for 2003 (AEO2003), scaled on the basis of available base year and growth rate information.
- *Light duty Vehicle stock turnover.* We used a simple stock turnover model developed at Tellus that considers aggregated vehicle technology categories and incorporates AEO2003 assumptions for vehicle survival rates and VMT decay rates. In California, we benchmarked results of the model to match light duty vehicle stock, VMT levels, and gasoline use levels obtained from the CARB.[54] In Oregon and Washington, we used AEO2003 assumptions for the Pacific region, and scaled to local conditions based on available base year and growth rate information.
- *GHG performance characteristics.* We evaluated the GHG (i.e., CO_2, CH_4, N_2O) performance of various vehicle technologies based on the full fuel cycle emission characteristics (i.e., upstream and at tailpipe) denominated in grams of CO2-equivalent per mile traveled (gm CO2-equiv/mile). We used values provided by the California Air Resources Board (CARB)[55]

4.2 Light-duty vehicle GHG emission standards

With the approval of AB 1493, the "Pavley Bill", in July 2002, California has moved to the frontier of improving vehicle GHG emissions. This bill requires that by January 2005, the state must develop and adopt regulations that achieve the maximum feasible and cost-effective reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks.[56]

The California Air Resources Board is currently drafting these regulations, with release expected in early to mid June of this year. Given the uncertainties regarding differences between the draft

[52] We used LDV sale projections are based on the EMFAC model provided by Doug Thompson at CARB
[53] Energy Information Administration (EIA), 2003. *Annual Energy Outlook - 2003*
[54] CARB, 2002. *Staff proposal regarding maximum feasible and cost-effective reduction of GHG emissions from motor vehicles, June*
[55] ibid
[56] This also includes any other vehicles determined by the state board to be vehicles whose primary use is noncommercial personal transportation in the state

and final form of the AB 1493 regulations, we do not attempt to precisely model "Pavley" implementation across California and the Northwest States. Instead we evaluate:

- a gram per mile standard for the full fuel cycle of new light duty vehicles that matches the schedule proposed by CARB in June 2004.[57]
- a further phase from 2015-2020, reducing the average GHG emissions rate for new vehicles to roughly half of 2002 levels by 2020.

A variety of technologies could be deployed over time to achieve these GHG reductions. In our assessment of technologies, we relied heavily on the June 14, 2004 staff report by California's Air Resources Board (CARB), which itself relied on recent vehicle technology studies as well as discussions with representatives from the auto industry, vehicle component suppliers, and leading researchers.[58] Technologies that reduce GHG emissions from internal combustion engines are typically associated with either modifications to the engine itself (e.g., fuel-air mix into the cylinders), transfer of motive power between engine and wheels through the drive train (e.g., hybridization), and/or overall vehicle changes (e.g., aerodynamics). In addition, fuel cell technology is increasingly being considered as a GHG-reducing option given its high efficiency and potentially low fuel cycle emissions. Importantly, most of the favorable technology combinations modeled by CARB yielded net present value of lifetime operating costs that exceeded retail technology prices.

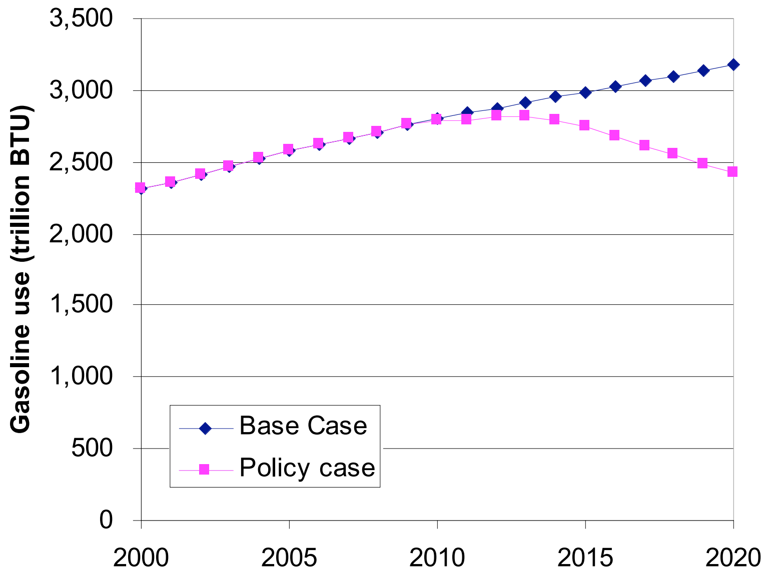
Figure 12 shows that this strategy could reduce total gasoline use in the West Coast to close to 2000 levels by the year 2020. The corresponding reduction in GHG emissions is about 56 MMTCO2e, and as such, the LDV GHG standards provide the single most potent strategy considered here.

These standards could save West Coast consumers at least $6.3 billion a year by 2020. This estimate is based on the June 2004 CARB Pavley staff report, scaled up to include Oregon and Washington vehicles. Under this scenario, consumers would pay an additional $1.2 billion (annualized) for new, lower GHG vehicles and would accrue about $7.4 billion in gasoline savings in 2020.

While the LDV GHG standard analyzed in our draft report is similar to the CARB staff proposal in near-term and mid-term – reducing new car emissions 30% by 2014 – it also considers longer-term technologies that could cut new vehicle GHG emissions in half by 2020. As a result, GHG savings are significantly higher than in the Pavley (AB 1493) proposal, and the net cost savings are likely to be significantly higher as well. CARB estimates that advanced hybrid technologies, capable of reducing emission below half of current levels, have an economic payback of 7 years for most car classes.[59] As discussed in Appendix C, deeper long-term GHG reductions are also cost-effective. Furthermore, it is likely that an LDV GHG standard would accelerate innovation and bring down the costs of advanced technologies below levels shown here. We have not estimated these additional savings, thus the CARB/Pavley estimate serves as a low estimate.

57 CARB, 2002. *Staff proposal regarding maximum feasible and cost-effective reduction of GHG emissions from motor vehicles, page iii, June*
58 ibid
59 ibid. See also discussion of LDV GHG standards in Appendix C.

Figure 12. Impact of LDV GHG emission standard on gasoline consumption (Trillion BTU)



4.3 Vehicle travel reduction policies for the light-duty fleet

While the preceding strategy reduces GHG emissions per mile driven, it does little to influence the other half of the vehicle emissions equation, i.e. the miles driven. Over the past decades, there have been significant increases in the number of car and light duty truck vehicle miles traveled (VMT) in each of the three states. These increases have led to increases in traffic congestion and major increases in tailpipe GHG emissions. Under the base case scenario, VMT for light duty vehicles in the three-state region is expected to increase from 355 billion miles in 2000 to about 513 billion miles in 2020, a growth rate of about 1.9% per year. This growth rate is a major driver of increased GHG emissions in the coming decades.

VMT reductions can be achieved through the implementation of various types of smart growth policies. These measures primarily affect urban passenger transportation and can result in a shift to higher occupancy vehicles, including carpooling, vanpooling, public transportation, speed limit controls, transit-oriented land use planning, and telecommuting. Numerous strategies that can reduce vehicle miles traveled (VMT) have been in play across the three states for many years, and several are widely recognized success stories. One prominent example is the Portland Growth Management program, which was based on dense central city development. This resulted in mixed-use development that reduced travel needs, the availability of alternatives to automobile transportation, and overall lower per capita travel by the population.[60]

Some regional investigations (and their VMT reductions estimates) concerning such measures include the California MPO analyses which indicated potential statewide VMT reductions of

[60] Central City Transportation Management Plan: Plan & Policy, City of Portland, http://www.sustainable.doe.gov/codes/cityportland/policy.htm

between 3% and 10%[61] and the LUTRAQ effort in Portland, Oregon which calculated potential VMT reductions of between 6% and 8% in the Portland region from new transit and coordinated land use planning.[62] Moreover, California's AB 2076 process for reducing petroleum dependence considered various smart growth strategies such as expanded public transit, land use planning, telecommuting, reduced speed limits, accelerated vehicle scrappage, and ridesharing. Combined, these California measures were estimated to be able to achieve about a 6% reduction in VMT by 2020.[63]

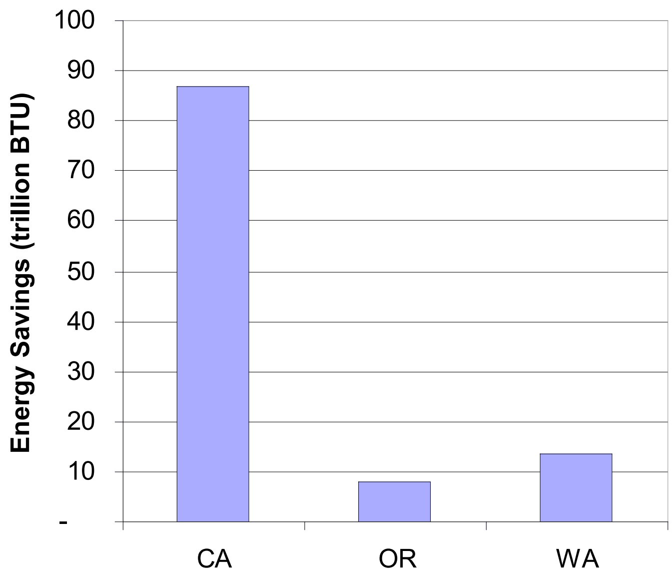
In our analysis, we selected 5% VMT reduction target, based on results from other studies, including CEC staff research. The mechanisms each state or metropolitan region to achieve 5% reductions might vary considerably. These could include measures with near-term emissions benefits, such as incentives for higher occupancy vehicles, public transportation, and telecommuting, as well as those with longer-term benefits, such as growth management and land use planning. They might also include public awareness and education campaigns.

This strategy reduces gasoline use by about 110 trillion BTUs for the overall region by 2020, with a corresponding reduction in emissions of about 8 MMTCO2e (assuming new vehicles are already meeting the GHG standard described above). State-by-state gasoline savings are shown in Figure 13 below.

The investment costs of a VMT reduction strategy are particularly difficult to quantify, given the complexities and multiple objectives of policies such as smart growth or mass transit. Smart growth and land use policies may reduce the costs of providing utility and road services by clustering development patterns. Mass transit policies may shift the incremental capital costs are shifted from private individuals to public agencies, with some strategies that increase overall capital costs and some that reduce them. As a result of these complexities, we consider only the benefits associated fuel savings, which total $8 billion on an NPV basis through 2020. Further analysis of individual VMT policies would help to clarify whether other expenditures are increased or decreased.

[61] Parsons Brinckerhoff, 2001. *California MPO Smart Growth Energy Savings MPO Survey Findings*, prepared for the California Energy Commission, September.
[62] Cambridge Systematics, Inc. and Parsons, Brinckerhoff, Quade & Douglas, 1996. *Making the Land Use* Transportation Air Quality Connection: Analysis of Alternatives. Vol. 5. Prepared for Thousand Friends of Oregon. May.
[63] Personal communication from Gerry Bemis, May 2004.

Figure 13. Impact of the VMT reduction strategy on gasoline consumption in 2020 (Trillion BTU)



4.4 Heavy-duty vehicle efficiency

Heavy-duty trucks represent a smaller percentage of GHG emissions than cars and light trucks. Yet, these trucks typically cover more miles each year, and have lower fuel economy and higher GHG per vehicle. Thus, this is an important class of vehicles to examine for possible reductions in fossil fuel use and GHG emissions.

Various vehicle systems and improved engine designs have been proposed to reduce emissions and energy use associated with heavy vehicles (predominantly trucks). Improving efficiency in heavy vehicles has mostly focused on the use of lightweight materials, tires with lower rolling resistance, and treatments to reduce aerodynamic drag. Researchers have estimated that a reduction in energy use by new vehicles of approximately 15% could be achieved from such measures.[64] Advanced diesel engine designs under development for use in heavy-duty trucks could also lead to reductions in fuel use. A range of engine modifications has been identified that achieve thermal efficiencies of around 55%, compared to conventional best-in-class efficiencies of about 48%.[65] Combining engine efficiency improvements with other measures, new heavy-duty vehicles could achieve overall efficiency improvements, and reductions in gCO2e/mi, of over 20%.

We assume that incentives or a heavy-duty vehicle GHG emissions standard could begin improving new heavy-duty vehicle GHG emissions rates starting in 2009. We assume target improvements in new heavy-duty vehicles of 11% by 2015 and 20% by 2020 relative to current levels.

---

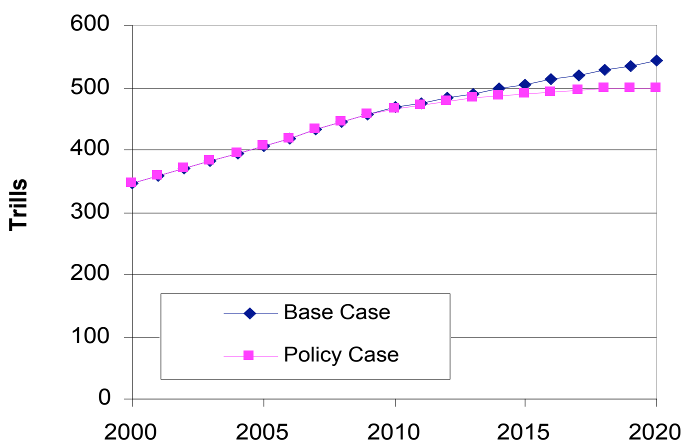
[64] Gaines, L., Stodolsky, F., and Cuenca, R. 1998. *Life-Cycle Analysis for Heavy Vehicles*, Argonne National Laboratory, June

[65] *Ibid.*

The results of our modeling assumptions for a GHG standard for heavy duty vehicles are shown in Figure 14. Total HDV diesel use in the region would decrease by 2020, though it would still be considerably in excess of 2000 levels by that year. The corresponding reduction in carbon dioxide would be about 3 MMTCO2e by 2020. The relative low level of savings is the result of conservative assumptions regarding heavy-duty vehicle turnover.[66] In general, given longer survival rates, turnover in the heavy-duty vehicle stock is slower than for light duty vehicles. This has the effect of stretching out the time required to realize the full impact of the more efficient new vehicles.

Limited cost estimates are available for HDV efficiency improvements. Therefore, we took a cost of saved energy approach in which we assumed that the marginal cost of conserved energy to achieve the efficiency improvements assumed matches the fuel price in each future year.[67] We applied this technique as a conservative approach in the absence of good cost information. These costs were compared against the benefits of avoided diesel fuel consumption. The overall cost savings are rather modest, totaling $200 million through 2020 (cumulative NPV).

Figure 14. Impact of the HDV GHG emissions standard on diesel consumption (Trillion BTU)



4.5 Alternative Fuels (Biofuel Standards and Hydrogen Initiatives)

Over the long run, achieving deep reductions in transportation emissions will likely require the development of alternative fuels that reduce the amount of GHG emissions per unit of fuel used. Furthermore, the development of alternatives to the predominant vehicle fuels (gasoline and diesel) offers many other benefits, including reduced oil dependence, regional economic development (e.g., for locally-grown biofuels), and potentially lower air pollution levels.

[66] We did not have time to calibrate a suitable stock turnover model to regional patterns.
[67] This method has been used, for example, in Alliance to Save Energy et al., 1997. *Energy Innovations* (see page 74-75)

Several strategies are currently being pursued to achieve these goals. Hydrogen is perhaps the most prominent. Its GHG benefits will depend greatly on the feedstocks and processes ultimately used to make it (from renewables to coal, with or without carbon capture and storage), deliver it (electricity and gas networks and/or a new hydrogen delivery infrastructure), and use it (direct use of hydrogen or on-board reforming of fossil fuels).

Since the focus of this analysis is on the period up to 2020, and most hydrogen analysts view a major hydrogen transition in the longer term, we consider a scenario with sales of hydrogen fuel-cell vehicles beginning in 2011 and rising to 2% of the new vehicle fleet in 2020. In our view, this represents an ambitious effort and requires developing the necessary hydrogen delivery infrastructure (e.g. a "hydrogen highway") as well as fuel cell technologies. We assume that this hydrogen is derived from on-site reforming of natural gas, and achieves roughly a 50% reduction in lifecycle GHG emissions relative to current conventional vehicle technology (CARB, 2004).[68]

The other alternative fuels we consider are biodiesel and cellulosic ethanol. These are biofuels that can yield full lifecycle GHG reductions and that can be blended with standard vehicle fuels and used without major engine modifications. Biodiesel is a renewable diesel fuel substitute that can be made by chemically combining any natural oil or fat with an alcohol such as methanol or ethanol. It can be produced in both its neat form (i.e., 100% biodiesel, also known as B100) and in blends with petroleum diesel (e.g., B20, or 20% biodiesel blend). It is available in today's market at a cost premium equivalent of up to about $50-100/tCO2eq saved.[69] Larger-scale production offers the potential for some future cost reductions. Low blends of biodiesel can be used in any normal internal combustion diesel engine with no modifications. Higher blends of biodiesel (over 20%) may require minor modifications. Accounting for the energy used to grow feedstocks and manufacture it, a 20% biodiesel blend offers a net lifecycle reduction of about 16% relative to diesel.[70] For modeling purposes, we consider the impacts of a 20% biodiesel blend in regional diesel supplies by 2020.[71]

Cellulosic ethanol can be manufactured from agricultural residues, forest and mill wastes, or short-rotation woody crops, and offers significantly greater lifecycle GHG emissions savings. The use of E95 (i.e., 95% cellulosic ethanol and 5% gasoline) results in at least a 79% reduction

[68] We did not evaluate the costs and benefits of hydrogen vehicles. They are likely to be quite expensive in the near-term, given the need to develop hydrogen infrastructure as well as the early status of fuel cell vehicles with hydrogen storage. Note that by 2020 similar levels of emissions reductions could be achieved at a net economic benefit through the LDV GHG standards. Hydrogen fuel cell vehicles run on reformed natural gas are expected to emit about half the CO2 per mile as current vehicles after accounting for upstream emissions, the same target as the LDV standard for 2020. However, hydrogen provides fuel diversity benefits, reduces local air pollution, and may help prepare for deeper reductions beyond 2020.

[69] Such estimates are highly dependent on the future price of diesel fuel.

[70] Sheehan, J. et al. 1998. *An Overview of Biodiesel and Petroleum Diesel Life Cycles*, A joint study by the U.S. Department of Energy, National Renewable Energy Laboratory, and the U.S. Department of Agriculture, Office of Energy. May 1998. This is a conservative assumption as some analysts indicate reductions in the range of 19% to 22%. http://www.afdc.doe.gov/pdfs/3812.pdf .

[71] Note that compressed natural gas (CNG) and liquefied petroleum gas (LPG) are reported to about 30% of lifecycle emissions reductions relative to gasoline (CARB, 2004). CNG vehicles are already growing in popularity. We do not consider them here because it is unclear whether the same efficiency improvements (from a Pavley-like standard) could be achieved with these fuels.

in GHG emissions relative to conventional gasoline, depending on the feedstock.[72] Processes to produce cellulosic ethanol are still under development; thus we assume that cellulosic ethanol enters the fuel market only in 2011. For modeling purposes, we consider the impacts of achieving a 10% cellulosic ethanol blend in regional gasoline supplies by 2020. The three states might wish to consider more flexible policies that would encourage fuel suppliers to meet equivalent goals for lower the net GHG emissions of fuel supplied, such as a GHG fuel content standard that could be met through various means.

The alternative fuels strategy could reduce GHG emissions by about 11 MMtCO2 in 2020. The large-scale introduction of alternative biomass-based fuels could be the highest cost strategy considered here. Both cellulosic ethanol and biodiesel are estimated to cost over twice as much as the fossil fuels they would replace, on a per BTU basis (See Appendix C). Unless gasoline and diesel prices rise above expected levels, cellulosic ethanol and biodiesel prices are likely to significantly exceed them, costing consumers about $5 billion over the period from 2010 to 2020 (NPV).For these fuels, the co-benefits of fuel diversity, reduced import dependence, and regional job creation are important motivators.

4.6 Combined Results

Across the region, the total emissions reductions from the four transportation strategies amount to 77 MMTCO2e in 2020, as illustrated in Table 12. This is sufficient to reduce emissions from light and heavy-duty vehicles to near 2000 levels. After these strategies, emissions from vehicles are 10 MMtCO2 above 2000 levels (242 MMtCO2). In contrast, jet fuel emissions are expected to grow by nearly 40 MMtCO2 from 2000-2020. These results suggest that significant reductions below 2000 levels may need to consider both deeper VMT reductions and freight strategies (such as modal shifts from road to rail and great use of local products), as well as mechanisms to reduce jet fuel consumption.

Table 12. Emissions Reductions from Transportation Strategies, all 3 states (MMTCO2e)

	2010	2020
LDV GHG Standards	1	56
VMT Strategies	3	8
Freight Strategies	0	3
Alternative Fuels	0	11
Total	4	77
Reduction relative to base case	*1%*	*18%*

[72] Wang, M., Saricks, C., and Santini, D., 1999. *Effects of Fuel Ethanol Use on Fuel-Cycle Energy and Greenhouse Gas Emissions,* Argonne National Laboratory, ANL/ESD-38

Appendix A. Methodology

The modeling for this study was based on a mix of results from published reports, combined with specific modeling of the transportation and electricity generation sectors. To the extent possible, we relied on information from California, Oregon and Washington sources. Each state has developed inventory of historical GHG emissions, which we used for estimating 1990-2002 emissions (not all states provided inventory of emissions for all years or all sectors).

Reference case

For the reference case projections of energy consumption in the residential, commercial, and industrial and transportation sectors, we used projections supplied by the California Energy Commission for California.

For Washington and Oregon, we used the Northwest Power Council's 5th Plan medium forecast to project electricity demands. For other fuels, we used output from the National Energy Modeling System (NEMS) of the U.S. Department of Energy, Energy Information Administration (DOE/EIA) (EIA, 2004).[73]

NEMS projects energy consumption for a broader regional level that covers the Pacific census region (Washington, Oregon, California, Alaska and Hawaii). We allocated energy demand to Oregon and Washington based on state-specific characteristics. Our projections of future energy demands account for state-specific projections of economic activity and demographic growth[74] for all demand sectors (i.e., residential, commercial, industrial, and transport) in each state and the evolution of energy-using technologies, which were provided by the regional demand modules of NEMS (EIA 2004).

For the electric sector, we used the fuel disclosure or related information produced by each state for 2002 (see Appendix B below). This information allowed us to estimate generation by type of plant and the efficiency of these plant types. For the projections of the mix of new generation and the efficiency of the new plants, we relied on output from the NEMS model. The NEMS model version, data and assumptions employed in this study were those of EIA's Annual Energy Outlook 2004 (EIA 2004).[75] NEMS takes account of the interactions between electricity supply and demand (aggregated residential, commercial and industrial), including the mix of competitive and still regulated pricing in the US. It accounts for the feedback effects between electricity market and power plant construction decisions, as well as the links between fuel demands, supplies and prices.

Our use of NEMS for this project focused on the Electricity Market Module (EMM), complemented by the Oil and Gas Supply Module (OGSM). The EMM starts with the detailed

[73] Further information on NEMS is available from the Energy Information Administration's website, http://www.eia.doe.gov/bookshelf/docs.html. See also Energy Information Administration (EIA), 2002. *Annual Energy Outlook 2004. http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2004).pdf*

[74] Economic (gross state product by subsector) and demographic projections were obtained from Economy.com.

75 We altered the EIA assumptions slightly to allow the capital cost of wind generation to decline as more wind generation is built. This learning function had been limited in the Annual Energy Outlook 2004 but other analyses report expected declines in future prices

fleet of existing power plants in the thirteen electric sector regions of the U.S, and also represents power imports from neighboring Canadian regions. It makes dispatch, construction, inter-regional purchase and retirement decisions based upon the regional electricity demands and the cost and performance characteristics of existing and new electric supply options, adhering to national pollutant caps and any state-level RPS requirements. It also takes account of cost reductions of new power plants with increased units in operation (learning and scale economies). The OGSM tracks changes in prices of natural gas and petroleum fuels based on changes in their demand.

NEMS divides the Western Electricity Coordinating Council into three regions – California, the Northwest Power Pool (WA, OR, ID, MT, WY, NV, UT), and the Rocky Mountain Power Pool (CO, NM, AR). However, since all three regions could provide electricity to any of the three states, we looked at the new generation across all three regions to estimate the mix of new generation to the three states. For generation added after 2002, we assumed the same mix of sources for each state, except some adjustments were made to account for the California renewable portfolio standard and retirement of California's aging natural gas plants.[76]

Thus, future generation was estimated as

$$\text{Generation}_{t,p} = \text{generation}_{2002,p} - \text{retired generation}_{t,p} + \text{new generation}_{t,p}$$

$\text{Generation}_{t,p}$	is the generation of plant type p in year t (in TWh)
$\text{Generation}_{2002,p}$	is the generation of plant type p in 2002 (in TWh)
$\text{Retired generation}_{t,p}$	is the generation of plant type p that has retired between 2002 and year t (in TWh)
$\text{new generation}_{t,p}$	is the generation of plant type p that has been added between 2002 and year t (in TWh)

with new generation estimated as the total generation required to account for new sales and retired existing generation multiplied by the fraction of plant type p in the mix of new generation.

Policy Cases

As described in section 2, we estimated the energy demand reductions from the buildings and facilities policies based on information from several recent analyses.

We used NEMS to estimate the impacts of the policy on the electricity supply sector. We ran NEMS with reduced electricity demand (to account for impacts of energy efficiency and CHP policies), with increased financial incentives for renewables (impacts of the renewable portfolio standards) and with financial disincentives for CO2 emissions (impacts of cap and trade on CO2 emissions). We modeled these policies together (i.e. the cap and trade policy case assumes that efficiency, CHP and RPS policies are also being implemented) to avoid double counting the

[76] Based on information from the NEMS base case we assume 30% of current gas generation would retire by

emission reductions. For each policy case, the NEMS modeling provided information on the mix of new generation the amount of retirement or reduced generation from existing plants.

***Strategy overlaps and avoiding double counting*:**

Several of the measures could potentially cause the same changes – for example, appliance standards, building codes, and a public benefits fund could all result in more efficient lighting installed in new buildings. If we looked at each strategy in isolation, we would end up double-counting some energy savings and emission reductions. Without very detailed modeling, it is difficult to precisely correct for these effects. Therefore we have adopted some rough corrections as follows.

1. We estimate the energy savings for each measure as if it were the only measure being applied. These energy savings are reported as "gross energy savings" in the sections for each measure.
2. To estimate overlapping savings as well as to chart combined energy savings, we assumed the following "order of implementation" for the measures: appliance standards, building code standards, efficiency program potentials (PBF / EPS), then combined heat and power. This order is only used for a calculation of total emission reductions.
3. We then estimate the required deduction of energy savings from one measure on the gross energy savings from the subsequent measure. Because we rely on a range of data sources for this analysis, we consulted with experts[77] and reviewed lists of the technologies impacted by the measures to arrive at the factors as shown below.

Table 13. Accounting for Strategy Overlaps

Fraction of *Appliance Standard* savings deducted *from Efficiency Program Potentials*	50%
Fraction of *Building Code* savings deducted *from Efficiency Program Potentials*	50%

[77] For example, Steve Nadel (ACEEE) advised the NY process which adopted the same assumed 50% "overlap" of appliance standards with utility program potential.

Appendix B: Electricity Accounting on Consumption vs. Production Basis

There are two general ways to account for electricity use and emissions: production basis and consumption basis. According to the production basis approach, only the GHG emissions within a regional boundary are counted. This approach is consistent with standard EPA inventory techniques, and national level accounting in agreements such as the Kyoto Protocol. However, it fails to reflect the emissions associated with electricity actually used, or purchased by retail electricity providers, to meet consumer demands within that region. Thus, an alternative approach is to adopt a consumption based approach to electricity emissions accounting. Indications are that West Coast states are leaning increasingly toward this approach.

For this analysis, therefore, we have adopted a consumption based approach. However, the estimation of consumption based emissions is not always as simple as production-based emissions, for which data have already been compiled as part of past state-level inventory efforts. In the case of the Oregon and Washington, consumption-based emissions have recently been calculated for 2002 (by the Oregon Governor's Global Warming Advisory Group and by Washington's Community, Trade, and Economic Development agency, respectively). For California, consumption-based electricity emissions can be deduced from the 2002 Gross System Power Mix (net of self-generation), which is calculated in a similar manner.[78] We also used California historical generation statistics, which have been compiled in a similar manner.[79] The state, however, has not calculated emissions from this generation mix. Therefore we used a study prepared by Lawrence Berkeley Laboratory for the CEC and the California Climate Registry, and benchmarked our emissions estimates to LBL's estimates of consumption based emissions in 1990 and 1999. (Marnay et al, 2002)

[78] http://www.energy.ca.gov/reports/2003-04-21_300-03-002.PDF
[79] http://www.energy.ca.gov/electricity/electricity_generation.html

Appendix C: Cost Analysis Data and Assumptions

Table 14. Costs of Saved Energy

Appliance Standards and Building Codes:	3.6	$/MWh
Energy Efficiency		
electricity	24.0	$/MWh
natural gas	5.7	$/MMBTU Residential and Commercial
	4.8	$/MMBTU Industrial
Combined Heat and Power	47.5	$/MWh Commercial
	41.6	$/MWh Industrial

Average values for the cost of saved energy, calculated as the annualized cost of increased capital costs for more efficient equipment divided by annual energy savings, are used in the analysis of buildings and industry measures.

Data sources and assumptions used to develop cost estimates include:

- **Appliance standards**: Detailed analysis of individual incremental technology costs and energy savings are based on data from the American Council for an Energy Efficient Economy (2004)

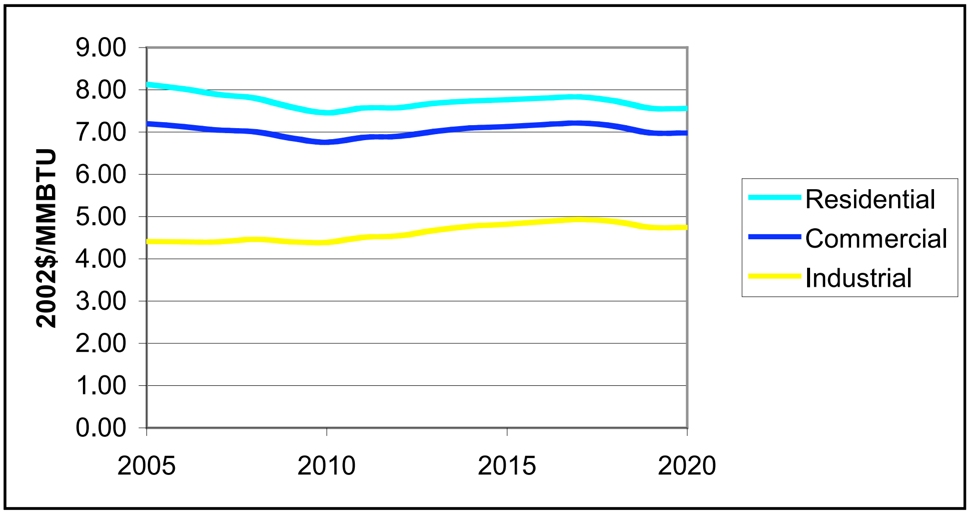
- **Energy efficiency programs**: The Northwest Power Council Draft 5th Power Plan conservation assessment, various KEMA/XENERGY studies for California and Puget Sound Energy, and the Oregon Energy Trust provided estimates of the cost of obtaining energy efficiency for electricity and natural gas. These costs reflect the incremental capital costs of more energy efficient equipment plus any relevant implementation and operating costs.

- **Combined Heat Power**: The figure shown above represents net cost of electricity production from CHP facilities (technology and operating costs of new equipment plus incremental natural gas use), based on data from an Onsite Sycom Energy report, [80] along with Tellus estimates of the mix of the size of CHP units.

Industrial Carbon Policy: The cost for the industrial carbon policy is based on incremental capital costs of more energy efficient technologies, as estimated by the American Council for an Energy Efficient Economy for the report, *Smart Energy Policies: Saving Money and Reducing Pollutant Emissions through Greater Energy Efficiency* (Nadel 2001). The cost savings from reduced fuel use are based on the energy prices shown in the technical notes, from the EIA Annual Energy Outlook 2004.

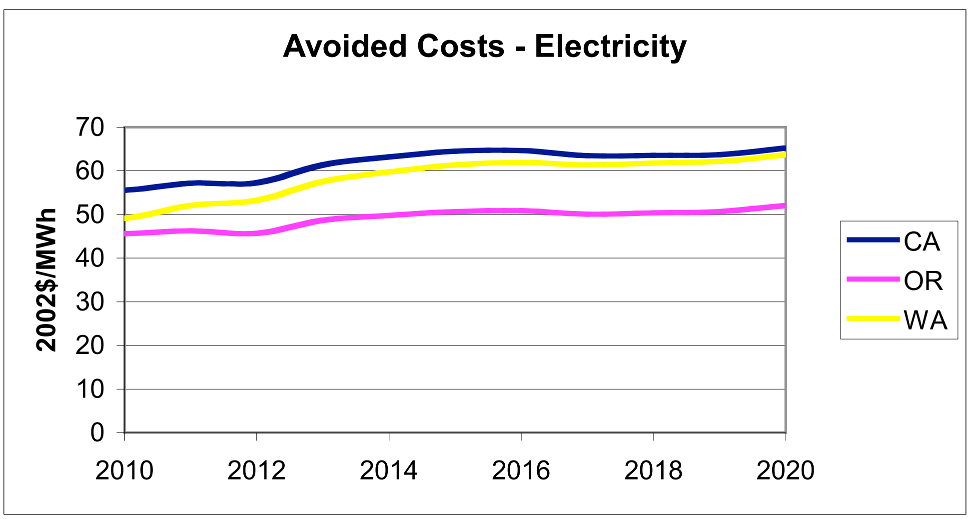
[80] Onsite Sycom Energy Corporation, The Market and Technical Potential for Combined Heat and Power in the Industrial Sector, and The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector, both prepared for the USDOE EIA, January, 2000.

Figure 15. Natural Gas Prices – Residential, Commercial and Industrial sectors (from NEMS runs)



Electricity technology costs and performance assumptions for power plants come from the *Assumptions for the Annual Energy Outlook 2004* (EIA 2004) and from the results of Tellus' analysis using the National Energy Modeling System (NEMS). Figure 16 shows the avoided costs for the electric sector of each state. These costs are the outcome of the modeling for this analysis – they represent the cost savings to the system from reduced electricity sales. Table 15 shows the cost and performance assumptions for new power plants and Figure 17 reports the fuel price assumptions for the electric sector.

Figure 16. Avoided delivered electricity costs by state (includes transmission and distribution costs)



Avoided electricity costs are used to calculate the cost savings from reductions in electricity sales due to efficiency, appliance standards, building codes and CHP. The avoided costs are calculated based on the mix of avoided new builds and reduced use of existing plants in each state. The avoided costs reflect the avoided capital, fuel, and operating costs of the plants plus avoided transmission and distribution costs, as used to evaluate demand-side efficiency improvements. For supply-side comparisons, avoided costs are about $15/MWh lower than shown, since transmission and distribution costs are not avoided.

Table 15

Cost and Operating Assumptions for New Generators in Western Region, based on AEO2004 (all costs in 2002$)

	Conventional Coal	Natural Gas/Oil	Biomass	Geothermal	Wind	Solar PV (central station)
Capital Cost ($/kW)						
Base case						
installed 2010	1,247	551	1,826	1,873	959	3,794
installed 2015	1,176	520	1,750	1,827	1,147	3,324
installed 2020	1,157	485	1,687	1,776	861	3,002
Policy case						
installed 2010	1,179	549	1,841	1,882	1,692	3,794
installed 2015	1,151	565	1,655	1,817	1,106	3,324
installed 2020	1,138	475	1,455	1,720	1,036	3,002
Back-up power ($/MWh)						
Base case					6	
Policy case					10	
Fixed O&M ($/kW-yr.)	25	10	46	100	26	10
Variable costs (excl fuel) ($/MWh)	3	3	3	0	0	0
Typical Size (MW)	600	250	100	50	50	5
Heatrate (BTU/kWh)	9,000	7,000	8,911	n/a	n/a	n/a
CO2/MWh	0.851	0.370	0	0	0	0

Notes: Capital costs vary by year and between the base and policy cases due to several factors 1) impacts of learning lead to lower capital costs as more capacity is built throughout the country (we assumed stronger capital cost decreases due to learning for wind than are assumed in the AEO2004), 2) for wind, the AEO includes assumptions on increasing capital costs as the best sites are used so increased capacity can lead to higher capital costs and 3) the fossil resources also have slightly higher costs at higher capacity so costs drop slightly in the policy case where efficiency and renewables lower the need for fossil capacity.

Figure 17. Fuel Prices for Electricity Generators

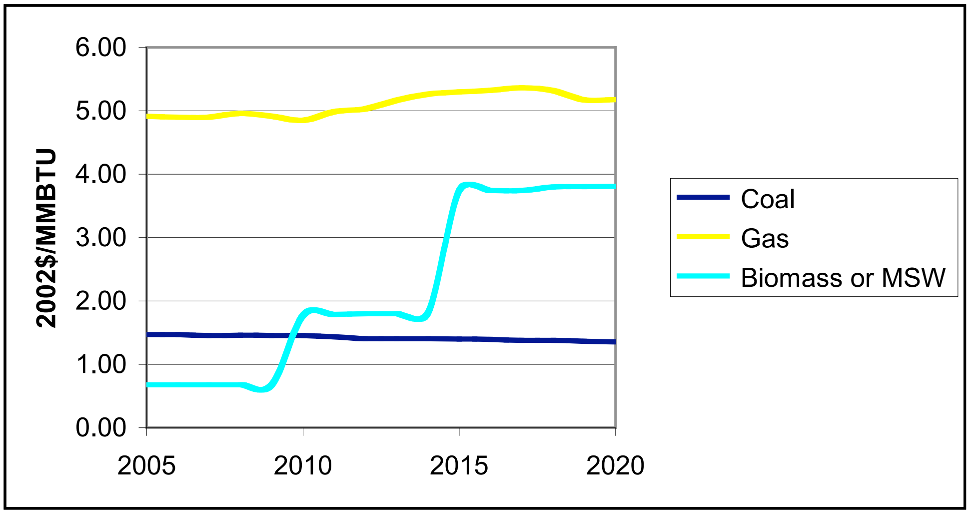
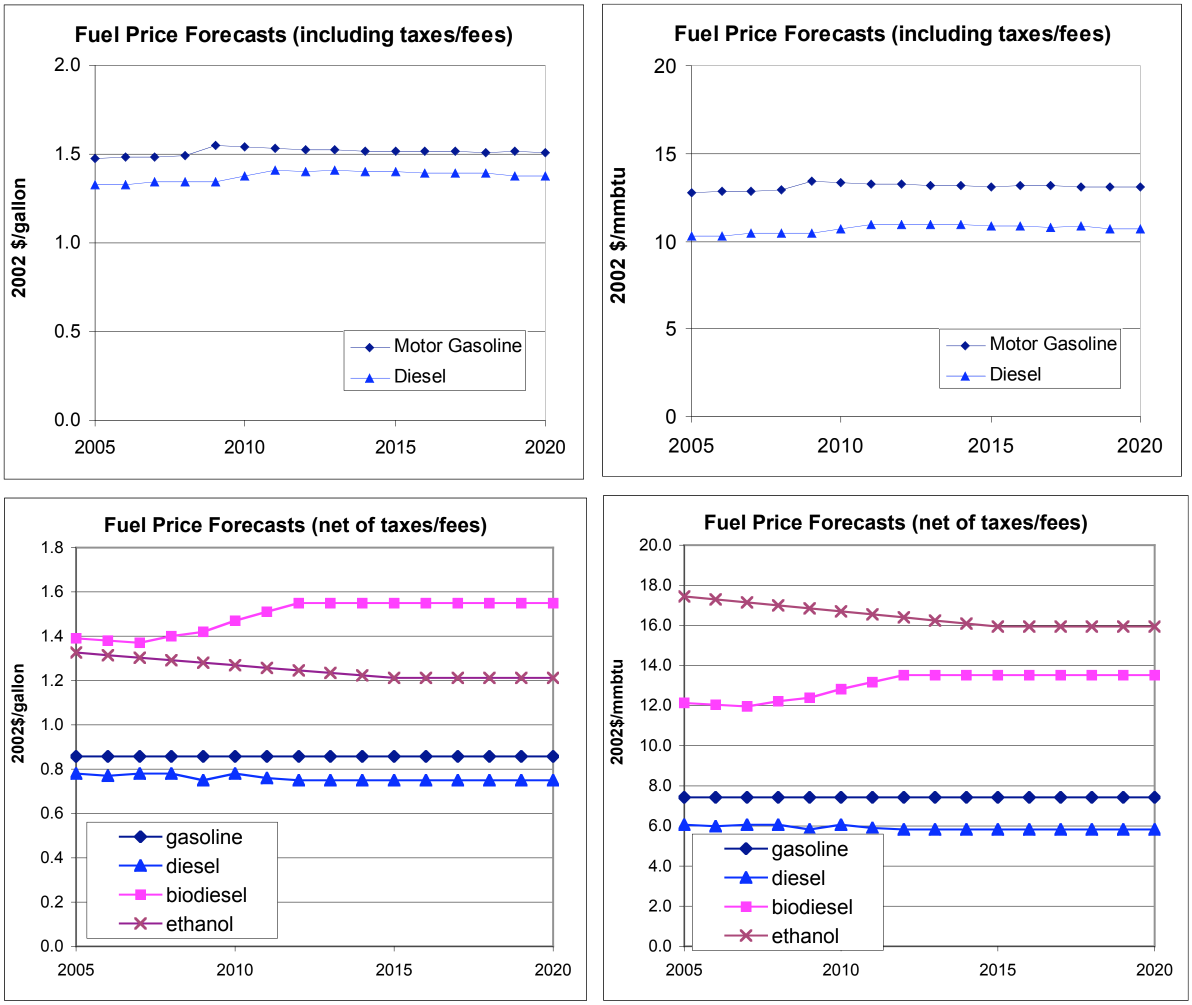


Figure 18. Transportation fuel price projections



Transportation fuel price projections are based on AEO2004 for the Pacific region, as summarized below for diesel and gasoline. The upper charts show retail prices, while the lower charts exclude state and federal taxes. Retail prices were used to evaluate the VMT and freight efficiency policies, while the pre-tax prices were used for the analysis of alternative fuels.

For the feedstock for cellulosic ethanol, it was assumed that it consisted of a combination of agricultural waste, forest residue, and energy crops. The production method assumed was hydrolysis. Cost components include the cost of the feedstock, and capital and operating costs. It was assumed that there is a continued expansion of cellulosic ethanol production infrastructure and that the federal 51 cents per gallon (nominal) subsidy is extended till 2020. Major assumptions are taken from DiPardo, 2000, "Outlook for Biomass Ethanol Production and Demand, EIA.

Our principal biodiesel assumptions including costs of feedstock and production are taken from the USDOE report: Radich, A., 2004. "Biodiesel Performance, Costs, and Use." USDOE

Energy Information Administration, www.eia.doe.gov/oiaf/analysispaper/biodiesel/index.html. We assumed that the feedstock for biodiesel is yellow grease (largely recycled cooking oil from restaurants), widely available in commodity markets. However, yellow grease source may not be sufficient to supply the requirements of reaching a full B20 blend by 2020 for the 3 state regions. In this case, higher priced soybean feedstocks would be needed, significantly increasing the incremental cost of biodiesel.

LDV GHG Standards: As noted above, we drew our cost savings directly from the June 14, 2004 CARB staff proposal for AB 1493. **Figure 19** below indicates that deeper long-term reductions (2015 and beyond) are also cost-effective.

Figure 19. Incremental Costs vs. Percent Reduction for Different Packages of Vehicle Technologies (from CARB, 2004)

Diamonds indicate near-term technologies, triangles mid-term, and Xs long-term. The CARB June 14 staff proposal only considers the near-term and mid-term. In this analysis we consider a transition to the long-term technology (advanced hybrid, far right X) by 2020.

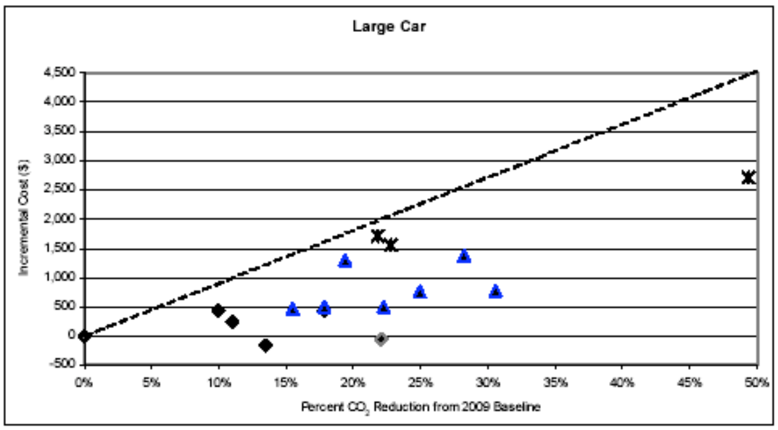


Figure 5-7. Incremental Costs for Technology Packages on 2009 Baseline Large Cars

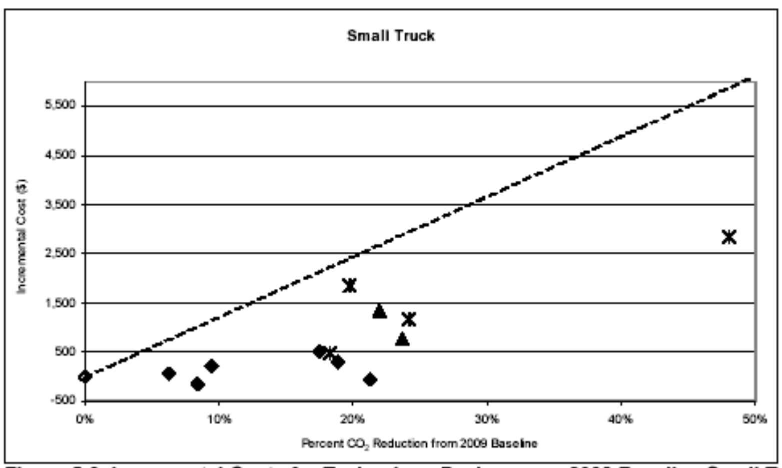


Figure 5-9. Incremental Costs for Technology Packages on 2009 Baseline Small Trucks

Appendix D: Other Data and Assumptions

Table 16. Expected Base Case efficiency program improvements
(cumulative, as % of that year's demand)

Residential Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	2%	4%	1%	1%
Oregon	2%	6%	2%	4%
Washington	1%	3%	1%	2%

Commercial Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	3%	6%	1%	2%
Oregon	3%	8%	1%	4%
Washington	1%	4%	1%	2%

Industrial Sector

	Electricity		Gas	
	2010	**2020**	**2010**	**2020**
California	1%	3%	0%	1%
Oregon	1%	2%	0%	0%
Washington	0%	1%	0%	0%

Sources:
Energy Trust of Oregon's (ETO) ten year goal of 300aMW
Oregon Governor's Advisory Group on Global Warming estimate of ETO natural gas savings
KEMA-XENERGY reports (as indicated for "current spending levels")
Washington assumed to capture potential at half the rate of Oregon estimates (lacking OR's public benefit charge).

Table 17. CHP Analysis Inputs

Sector	MW	aMW **	% from new facilities	Net Cost of Electricity* $/MWh	Gas cost $/ MMBtu	Net heat rate Btu/ kWh
Commercial	235	214	63%	$47.5	$7	4856
Industrial	231	211	21%	$41.6	$5	5298

* Net cost of electricity is calculated as the levelized cost of added natural gas use plus CHP equipment divided by electricity produced. Estimates are based on a weighted average of several commercial sizes (100kW to 800kW ICEs and Microturbines) and industrial sizes (800kW to 40MW ICEs and CTs), based on previous studies and market analyses (Tellus 2002 and Onsite Sycom 2000)
**Capacity Factor 91% per earlier studies (8000 hrs/year)
Natural Gas Emission Factor 53.1 tCO_2/ billion Btu

Table 18. Assumptions for appliances analyzed (from ACEEE, personal communication)

ACEEE Standards Analysis, Key Input Assumptions 5/7/04

Products	National Annual sales (2001) (million)	Current Standard or Baseline	New Standard or Average Use	Unit	Basis for New Standard	Effective Date (Year)	Average Product Life (Years)	Annual Baseline Use per Unit	Annual Savings Per unit	Unit	Per unit Incremental Cost ($)
Beverage merchandisers - Tier 1	0.14	4438	4077	kWh	CEC 2004	2006	8.5	4438	361	kWh	19
Beverage merchandisers - Tier 2	0.04	4077	2711	kWh	30% below CEC 2004	2006	8.5	4077	1366	kWh	71
Ceiling fans (with lights)	13.05	Incand.	CFL		E* lamps	2007	13	213	132	kWh	6
Comm'l clothes washers	0.27	0.82	1.26	MEF	Same as Resid. +WF	2006	8	see below breakdown			137
electricity	*0.04*					*2006*	*8*	*564*	*197*	*kWh*	
natural gas	*0.04*					*2006*	*8*	*94*	*33*	*therm*	
water	*0.04*					*2006*	*8*	*54203*	*9849*	*gallons*	
Comm'l packaged A/C (over 20 tons) - Tier 1	0.04	8.5	10	EER	CEE Tier 2	2006	15	67468	10120	kWh	1,260
Comm'l packaged A/C (over 20 tons) - Tier 2	0.04	10	10.5	EER	CEC proposed 2nd tier	2010	15	57348	2731	kWh	924
Comm'l refrigerators & freezers - Tier 1	0.23	4651	4111	kWh	CEC 2004	2006	9	4651	540	kWh	29
Comm'l refrigerators & freezers - Tier 2	22.00	4111	3416	kWh	Energy Star & CEE T1	2006	9	4111	694	kWh	37
Dehumidifiers - Tier 1	0.99	972	816	kWh	Energy Star	2006	15	972	156	kWh	1
Dehumidifiers - Tier 2	0.99	816	735	kWh	Revised Energy Star	2006	15	816	82	kWh	1
Dry type transformers	22.00	76	59	kWh	TP-1	2005	30	76	17	kWh	3
Exit signs	1.35	28.5	3	Watt	E-Star (LED)	2005	25	250	223	kWh	20
External power supplies	203.0	39.4	30.5	kWh	Ecos proposal, tier 1	2006	7	39	9	kWh	0.54
Ice-makers	0.23	3746	3327	kWh	CEE Tier 1	2007	8.5	3,746	419	kWh	30
Metal halide lamp fixtures	2.93	460	390	Watts	Pulse start ballast	2007	20	2,015	307	kWh	30
Digital cable and satellite TV boxes	9.10	20	15	Watt	Energy Star Tier 1	2006	5	182	50	kWh	5
Digital TV converter boxes	9.20	6	3	Watt	Energy Star Tier 1	2006	7	53	26	kWh	5
Pre-rinse spray valves	0.35	3.15	1.8	gpm	Based on pro. to CEC	2006	5	see below breakdown			5
natural gas	*0.35*	*1,566*	*1170*	*therms*	*Energy Star Tier 1*	*2006*	*5*	*1,566*	*396*	*therms*	
water	*0.35*	*3.15*	*1.8*	*gpm*	*Based on pro. to CEC*	*2006*	*5*	*4574*	*1157*	*gallons*	
Torchiere lamps	12.20	344	75	Watt	<190W (mostly CFL)	2005	10	414	288	kWh	20
Traffic signals	0.54	108.5	10	Watt	E-Star (LED)	2005	10	475	431	kWh	85
Unit heaters (nat. gas)	0.23	67%	80%	Seas. Eff.	Power draft	2006	19	1,644	267	therm	277
Vending machines - Tier 1	0.25	4449	4047	kWh	Lighting only, in 20% of s	2006	10	4,449	402	kWh	25
Vending machines - Tier 2		4047	2891	kWh	Draft Energy Star spec	2006	10	4,047	1,156	kWh	75