Climate Action for Economic Growth

An Economic Assessment of California's Global Warming Solutions Act

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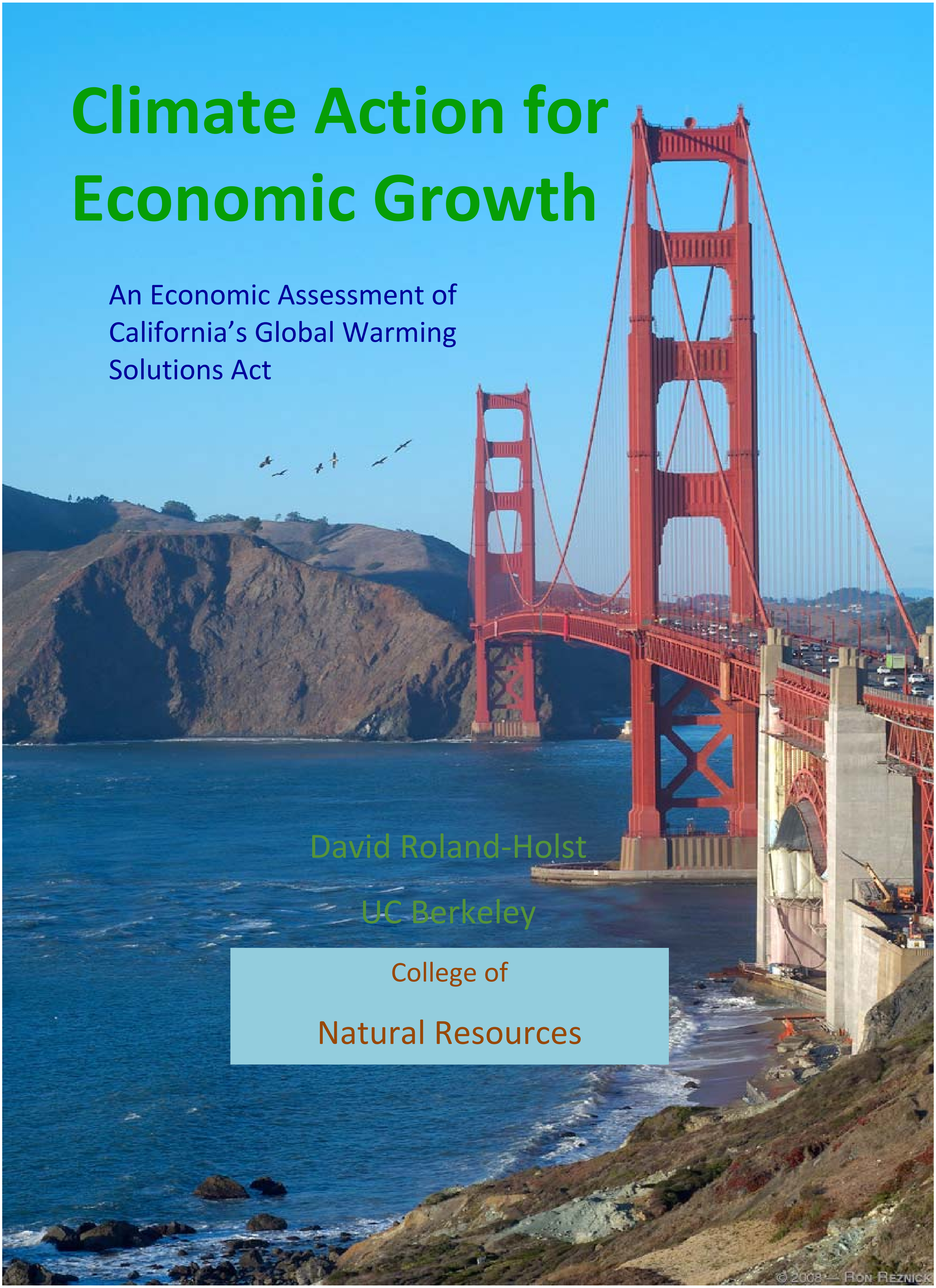

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Research Papers on Energy, Resources, and Economic Sustainability

This report is part of a series of research studies into alternative energy and resource pathways for the global economy. In addition to disseminating original research findings, these studies are intended to contribute to policy dialogue and public awareness about environment-economy linkages and sustainable growth. All opinions expressed here are those of the authors and should not be attributed to their affiliated institutions.

For this project on Climate Action and the California economy, financial support from the Energy Foundation and the Richard and Rhoda Goldman Fund are gratefully acknowledged.

Special thanks are due to the many talented research assistants who provided valuable input to this report: Special thanks to the following research assistants: Drew Behnke, Alex Cheng, Billie Chow, Melissa Chung, Fritz Kahrl, Elliot Deal , Sam Heft-Neal, and Shelley Jiang.

Marcus Schneider, Jane Bloch, Pamela Allen, Chris Busch, Michael Gibbs, William Dean, Fredrick Kahrl, and Sophie Turrell offered many helpful comments. We have also benefitted from the research insights of too many colleagues to list by name here, all of whose dedication is advancing our understanding of climate change and the policy challenges it presents. Opinions expressed here remain those of the author, as do residual expository and interpretive errors, and should not be attributed to their affiliated institutions.

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EXECUTIVE SUMMARY

California's determined response to rising Greenhouse Gas (GHG) emissions has drawn the world's eighth largest economy into an unprecedented policy dialogue that will influence energy and environmental decisions around the world. Within the state, we know that policies already implemented and under consideration, including the path breaking Global Warming Solutions Act, will have far reaching economic consequences, yet the sis for evidence on these effects remains weak. While no substantive mitigation policy can be without some direct and indirect costs, the benefits from greater energy efficiency and improved environmental conditions can significantly outweigh these. Thus responsible climate action assessment requires consideration of both the magnitudes and composition of adjustment costs and benefits. The primary objective of this report is to strengthen the basis of evidence in this area, particularly to contribute independent research to the policy dialog how to sustain and propagate the benefits of a more carbon-efficient future.

Table ES 1: Main Findings

1. *Aggregate growth effects of AB32 on the California economy are negligible or positive*
2. *Innovation responses could leverage climate policy and deliver significant growth dividends across the state.*
3. *Participation in a national climate program will reduce adjustment costs and increase benefits for California.*
4. *Individual sector demand, output, and employment can change significantly*
5. *No significant leakage is observed.*

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AB32 Assessment

One of the most advanced examples of such independent climate policy research capacity is the Berkeley Energy and Resource (BEAR) model. BEAR is a detailed and dynamic economic simulation model that traces the complex linkage effects across the California economy as these arise from changing policies and external conditions. The research summarize below is part of a larger effort to assess the long term implications of AB32 for the California economy.

As part of their advanced Scoping Plan and implementation activities, CARB and CalEPA organized a comparison project featuring the leading economic assessment tools applied to AB32 since its passage in 2006. These economic models, EDRAM from CARB, BEAR (reported here) from UC Berkeley, and MRN/NEEM from CRA/EPRI, have been the most prominent sources of empirical evidence supporting policy dialogue on AB32 and its many design characteristics. The intent of this exercise was to identify salient similarities and differences between approaches, the results they obtain, and resulting insights/inferences.

In particular, the three models were re-calibrated to the latest available information on AB32 component policies (see the Annex below). Implementing the three models in parallel then offers multiple perspectives on the costs and benefits of the Scoping Plan components. The BEAR model is peer reviewed and fully documented elsewhere. We summarize the main findings if its implementation here. In addition to the general macroeconomic results of the comparison project, this report is the first to provide detailed evidence on individual sector adjustments that can be expected to arise from AB32.

Scoping Plan and Related Policies Evaluated

For purposes of policy comparison, BEAR was used to evaluate two representative scenarios that take account of Scoping Plan policy recommendations. These generic scenarios are all for policies currently being evaluated for their potential to meet the state's 2020 target of 427 MMTCO2 equivalent overall emissions of greenhouse gases, and are discussed in detail in the main body of the Plan. The salient policy components are combined in eight different ways, described with supporting assumptions in Table ES 3 below.

Table ES 2: Policy Scenarios

	Offsets	LCFS	Pavley II	VMT Reduction	EE Standards	33% RES	CHP	Annual EE Response
ARB1	4%	Full	Full	Full	Full	Full	Full	None
ARB2	No	Full	Full	Full	Full	Full	Full	None
ARB3	4%	Half	Half	Excluded	Full	Full	Full	None
ARB4	4%	Full	Full	Full	Half	Excluded	Half	None
ARB5	4%	Half	Half	Excluded	Half	Excluded	Half	None
ARB_Cap	4%	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	None
EE1	4%	Full	Full	Full	Full	Full	Full	0.40%
WM1	Full	Full	Full	Full	Full	Full	Full	None

Table ES 3: Assumptions

	Component	Assumption
1	GHG Pollutants	CO2, CH4, N2O, SF6, PFC, and HFC
2	2020 Goal	15% below 2005 emissions
3	Covered Sectors	
	2012-2014	Electricity and Large Industrials
	2015-2020	Electricity and Large Industrial, transportation fuels, commercial and residential fuels and small industrial
4	Banking	Allowed without limitation
5	Cap Trajectory	Linear phase-in
6	Allocation	100% Auction
7	Offsets	No offsets With offsets at 49% of reduction
8	EE: Energy Efficiency	Assume California sustains 1% EE improvement per year to 2020
9	WM	California is part of a Waxman-Markey national climate initiative (ACES)

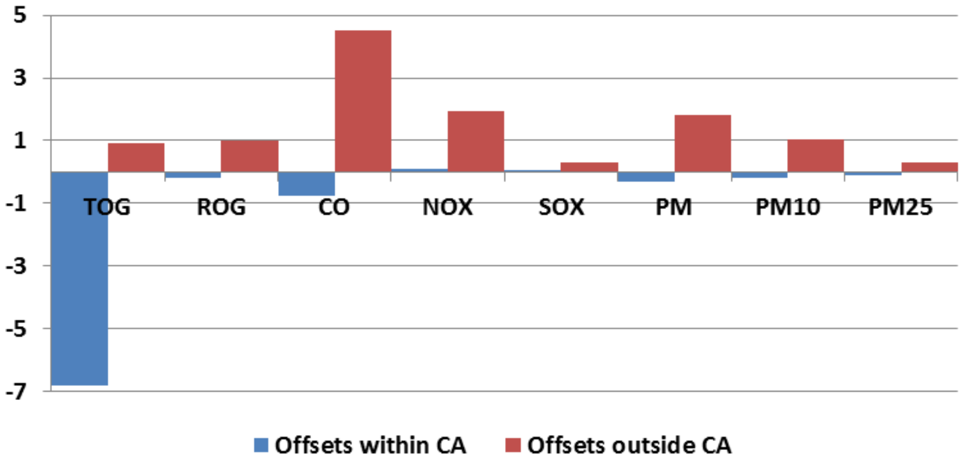
The eight cases above represent the core policy packages assessed by the BEAR model. CARB evaluated the first five in their assessment, while CRA evaluated the first six. Thus all three models are comparable for Scenarios ARB1-5, while BEAR and CRA can be compared for all cases except EE1. Like BEAR, CRA's model has an intertemporal framework, permitting annual projections over the policy period 2010-2020. CARB's own EDRAM model is comparative static, and only produces single estimates imputed to the terminal year (2020) under consideration.

Offsets

The AB 32 Scoping Plan proposes that out-of-state offsets be allowed to substitute for up to 49 percent of the total global warming emission reductions in all of the capped sectors. Because direct sector policies are expected to account for roughly 80% of emission reductions in the capped sectors, cap and trade alone is expected to achieve the remaining 20 percent of needed emission reductions. By allowing offsets equivalent to 49 percent of total reductions (as opposed to cap and trade reductions), this could mean that all of the emission reductions expected to be achieved in California by the cap and trade program could come from offsets.

Figure ES 1: Criteria Emissions from Offsets

(metric kiloton change from 2020 baseline)



The results of the BEAR assessment show that if out-of-state offsets are permitted to substitute for 50% or more of the cap and trade emission reductions, criteria pollution rises as compared to the baseline. This means that, in cases where AB 32 reduces criteria pollutants, these reductions will be undermined. In cases where the economic stimulus aspects of AB 32 cause pollution increases in some sectors, like transportation and construction, these pollution increases will be exacerbated.

Offsets also forsake the opportunity for innovation, and for the higher income, technology intensive economies like California, this may be their most serious drawback. The primary drivers of California's superior growth experience over the last two generations have been education and innovation, which have gone hand in hand to make the state a knowledge-intensive leader in the global economy. First in information and communication technology (ICT), then in biotech, the state's R&D supply chain has delivered solutions for the most dynamic and profitable sectors of modern times.

Renewables Deployment

Renewable energy is playing an increasingly important role in climate policy, and California has set an ambitious 33% Renewable Portfolio Standard as part of its AB32 initiative. A large part of the renewable energy mix, solar, wind, and geothermal, represent a fundamentally new energy supply paradigm. Fossil fuel supply and price are determined by scarcity, but these renewables represent essentially boundless resources relative to today's energy requirements. Instead, the constraint in this energy supply is not scarcity, but technological change. Recent trends in renewable technology suggest that these costs can be expected to fall over time. A clear commitment in the world's eighth largest market will be a strong stimulus for investment and innovation, including scaling up that can significantly reduce unit costs.

To calibrate the BEAR model with respect to renewable energy sources, we developed our own detailed estimates from the more recent sources available. We then combine this information with other data and assumptions regarding renewable and conventional energy alternatives, presented in

Figure ES 2 in terms of total cost per kWh of electricity, comparing the main intermittent renewable sources with a state-of-the-art Natural Gas Combined Cycle (NGCC) generation technology. Because fuel costs are an essential determinant of conventional costs, we present estimates under three LNG price scenarios, today's prices, Department of Energy Reference 2020, and International Energy Agency Reference 2020.

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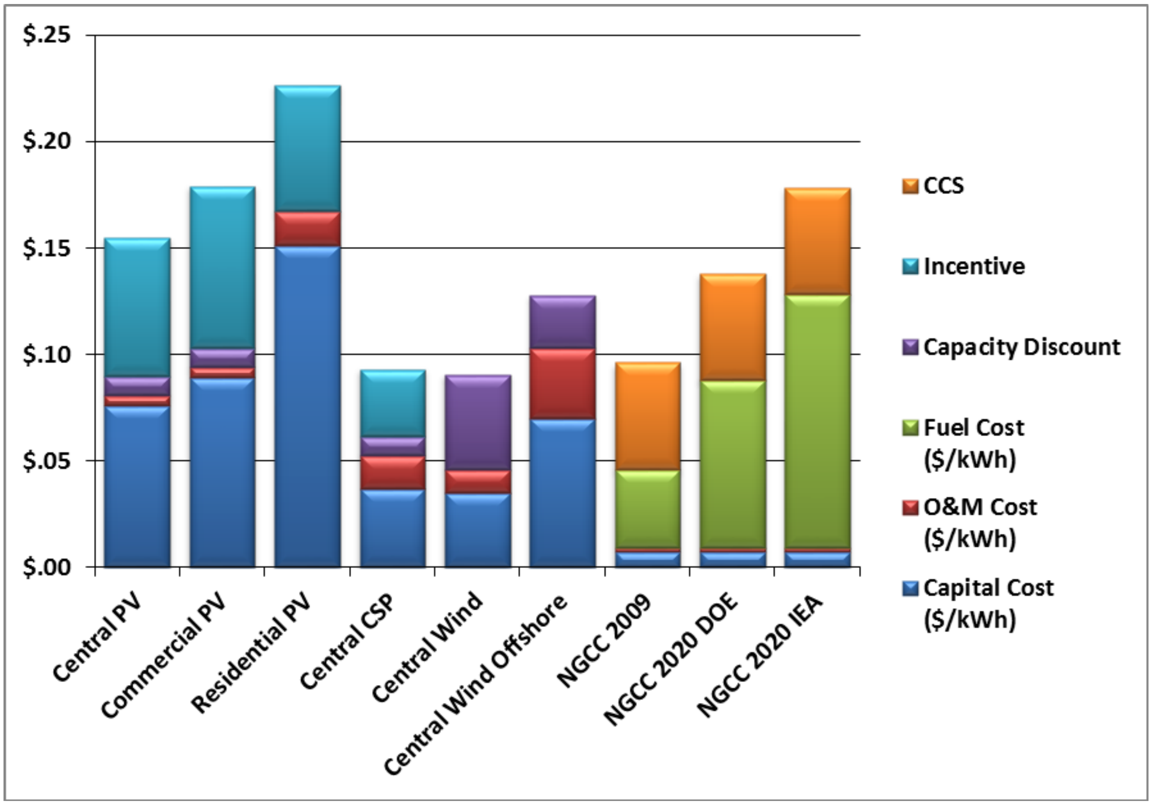
Figure ES 2: Renewable and Conventional Energy Cost Estimates



Source: Roland-Holst, David "Energy Prices and California's Economic Security," Next10.org, October, 2009.See the Annex below for estimation details.

Aggregate Economic Impacts

When the BEAR model was applied to the five Scoping Plan cases, aggregate economic impacts were consistent with CARB own current findings and BEAR's own results for a similar exercise in

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2007. Although BEAR has been updated to 2008 data for the California, from 2003, and the state economy has weathered significant adversity in the meanwhile, we still find that the overall economic costs of AB32 are negligible or even negative.

Table ES 4 summarizes the BEAR results for the eight scenarios considered. The most arresting feature of these results is the negative aggregate cost results for cases 7 and 8. The overarching reason for this is energy efficiency, which results directly from standards in the policies and indirectly from imposing costs on carbon fuels. As California learned from three decades of experience, saving money on energy shifts expenditure from the carbon fuel supply to more conventional spending patterns. The latter are much more employment intensive, leading to net job creation and indirect multiplier benefits that outweigh direct adoption and adjustment costs.

Even in cases where aggregate impacts (GSP) are growth negative, the magnitude is so small that it represents a few months of average baseline GSP growth. In other words, even in the worst case considered California can achieve a decade of climate objectives and realize the same aggregate wealth only about 5 months later, while achieving unprecedented mitigation of global warming pollution.

Table ES 4: Macroeconomic Impacts

(percent change from 2020 Baseline unless otherwise noted)

	1	2	3	4	5	6	7	8
	ARB1	ARB2	ARB3	ARB4	ARB5	ARB_Cap	EE1	WM1
Total GHG	-14	-19	-14	-14	-14	-14	-14	-9
Household GHG	-13	-13	0	-13	0	1	-13	-8
Industry GHG	-15	-23	-24	-15	-24	-24	-15	-10
Annual GSP Growth	-0.1	-0.2	-0.3	-0.5	-0.7	-0.9	3.0	0.7
Employment	-0.1	-0.1	-0.2	-0.3	-0.4	-0.5	2.2	0.9
Permit Price	$ 18	$ 74	$ 97	$ 83	$ 108	$ 132	$ 16	$ 34
Income Per Capita ($/yr)	-65	-72	-129	-252	-317	-417	1,389	327
Jobs (thousands)	-16	-18	-40	-56	-81	-101	397	73

The presence of offsets in Scoping Plan policies has an ambiguous effect. When offsets are not allowed (Scenario 2) the growth cost is higher. When offsets are completely permissible in a national trading system, there is substantial growth. This flexibility may seem attractive, but offsets are not the main driver of growth in Scenario 8. In any case, it must be remembered that offsets deny the state mitigation potential for other co-pollutants, including criteria toxics. Furthermore, extensive recourse to offsets averts innovation opportunities for California entrepreneurs, locally and, with technologies incubated in California, in the next break-out knowledge intensive industry. Energy is by revenue the world’s largest industry, and energy efficiency can be to that industry what IT was to management, revolutionizing traditional practices around the world. One of the primary benefits of AB32 could be induced innovation, allowing California businesses to capture the momentum of an explosive emerging global market.

The EE1, or innovation scenario, is by far the most pro-growth. The reason for this is expenditure shifting and multiplier effects coming from two sources. A carbon trading system provides a direct and transparent incentive to reduce carbon fuel expenditures, and to change expenditure patterns in ways that promote innovation. If users face the prospect of paying for pollution rights, the revenues go toward public goods and services that are more employment intensive than would be higher fuel spending. Those who avoid permit fees by investing in energy efficiency will save money in the long run, spending it on more conventional and generally more job intensive alternatives. This pattern of direct and indirect expenditure shifting has for a generation helped California to ever higher environmental and living standards. The future holds the same promise for positive, innovation based synergy between environmental values and livelihoods, and forward looking policies like AB32 can help to realize this potential, securing prosperity for another generation.

In comparison to the other two main approaches to AB32 assessment, the treatment of innovation distinguishes the BEAR approach. CARB's own study and that of CRA assume the CA economy adopts an unprecedented package of carbon pricing and energy standards without any induced technological change. This contradicts not only economic intuition but experience.

The best evidence available on this is California itself, which has maintained a combination of appliance and building standards and utility incentive programs since the early 1970's. In response to this, and even without pricing carbon, the eighth largest economy sustained an average of 1.5% energy efficiency improvements for three decades. In the BEAR analysis, we made the modest assumption that CA responds to AB32 with 1% average improvements over the period considered (i.e. about two-thirds California's historical innovation progress for about half the time). The expenditure shifting benefits of this energy saving (Figure ES 3) more than compensates for the adverse effects found by others.

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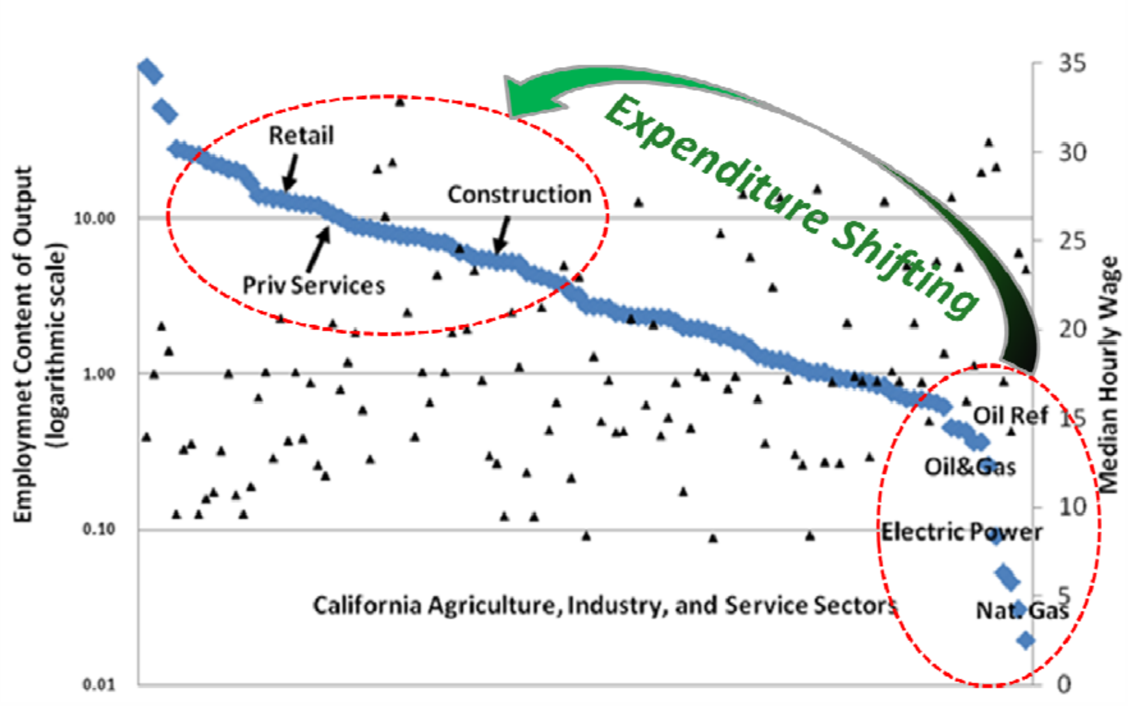
Figure ES 3: Why Energy Efficiency Creates Jobs



Source: Roland-Holst, David "Energy Efficiency, Innovation, and Job Creation in California," Next10.org.

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CONTENTS

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INTRODUCTION

Over the last five years, economists at UC Berkeley have conducted independent research to inform public and private dialogue surrounding California climate policy. Among these efforts has been the development and implementation of a statewide economic model, the Berkeley Energy and Resources (BEAR) model, the most detailed and comprehensive forecasting tool of its kind. The BEAR model has been used in numerous instances to promote public awareness and improve visibility for policy makers and private stakeholders.[1] In the legislative process leading to the California Global Warming Solutions Act (SB32), BEAR results figured prominently in public discussion and were quoted in the Governor's Executive Order to carry out the act.

While researchers who developed and implement the BEAR model do not advocate particular climate policies, their primary objective is to promote evidenced-based dialogue that can make public policies more effective and transparent. California's bold initiative in this area makes it an essential testing ground and precedent for climate policy in other states, nationally, and internationally. Because of its leadership, the state faces a significantly degree of uncertainty about direct and indirect effects of the many possible approaches to its stated goals for emissions reduction. High standards for economic analysis are needed to anticipate the opportunities and adjustment challenges that lie ahead and to design the right policies to meet them.

In addition to proesenting macroeconomic analysis from the CARB model comparison project, this study reviews an extensive body of evidence at the industry level, first examining publically available information on the technology and cost structures of so-called first and second-tier emitters in California. These sectors are most likely to be included in a cap and trade system because they make large aggregate or relative contributions to CO2 emissions and can therefore make important contributions to reducing climate change risk. Our general finding is that all of these sectors can make the needed contributions, particularly under a well-designed cap and trade system that uses a market mechanism to more efficiently allocate the burden of adjustment.

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[1] See e.g. Roland-Holst (2006ab, 2007a).

More detailed characteristics of the adjustment process remain uncertain, but some impacts could be substantial at the industry and particularly the plant level. The actual magnitudes will depend critically on the incentive properties of the policy design. For example, the degree to which firms pass on adjustment costs to consumers will depend upon competitive conditions in each industry and the extent to which policies promote investment in efficiency. If the state is to maintain its leadership as a dynamic and innovation oriented economy, it is essential that Climate Action policy include explicit incentives for firms to follow competitive innovation discipline, investing in discovery and adoption of new technologies that offer win-win solutions to the challenge posed by climate change for their industries and for consumers. In this way, California can sustain its enormous economic potential and establish global leadership in the world's most promising new technology sector, energy efficiency, as it has done so successfully in ICT and biotechnology.

In addition to our focus on first- and second-tier emitters, we use a state-of-the-art economy-wide forecasting tool, the Berkeley Energy and Resources (BEAR) model, to simulate the economic consequences of a variety of energy policy scenarios for California on the sectors not included in the first- and second-tier category. After detailed examination of a range of actual and proposed policies, we find that the aggregate economic benefits of many GHG mitigation policies outweigh their microeconomic costs. Moreover, some of the most prominent policies have the potential to help meet the state's ambitious GHG reduction objectives, while at the same time stimulating aggregate economic growth by increasing productivity and efficiency.

For a package of GHG mitigation policies that comprise AB32, first recommended in 2005 by the California Climate Action Team (CAT), will trigger general macroeconomic effects via structural linkages that transmit economic impacts across the state economy. A consistent feature of these results was the economic importance of cumulative indirect and linkage effects, which in many cases far outweigh direct effects. Although the majority of the GHG responses and direct (adoption and monitoring) costs are easily identified, economic benefits of these policies extend over long supply and expenditure chains, the cumulative effect of which can only be assessed with methods like the one used here.

Three salient institutional insights emerge from the economic analysis:

1. A variety of policies under active consideration could reduce GHG emissions significantly, at negligible or negative net cost to the overall state economy.

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2. Policies that achieve higher levels of energy efficiency permit resources to be reallocated within the state economy, reducing external energy dependence and increasing in-state value added and employment.

3. With improved information and appropriate incentives, most of the GHG policies considered can enlist significant private agency at a public cost that is a small fraction of their potential benefit.

These general conclusions are supported by a myriad of more detailed structural adjustments, the elucidation of which can be essential to design and implement effective policies.

Rigorous policy research tools like the BEAR model can shed important light on the detailed economic incidence of energy and climate policies. By revealing detailed interactions between direct and indirect effects across a broad spectrum of stakeholders, simulation methods of this kind can support more effective policy responses to climate change.

Many studies emphasize the costs of policies that deal with climate change because they look only at the direct effects. This one finds that many policies under active consideration in California actually *save money* and *increase employment* overall because the *indirect and incentive effects* are so important. These overall benefits only become apparent when the economywide implications and innovation potential of the policies are taken into account. For example, we shall see below that energy savings allow consumers to increase other spending, largely on in-state goods and services, and this stimulates California growth and employment. Industry-specific and bottom-up studies of GHG polices fail to capture these indirect benefits, giving disproportionate emphasis to direct costs. An economywide perspective like that of the BEAR model is needed to balance the adjustment and growth perspectives.

SCENARIO ANALYSIS FOR CARB’S SCOPING PLAN

California has well-established leadership in policies related to climate change, including a broad spectrum of energy and emissions initiatives that have set national standards for economic growth through innovation and efficiency. These policies have targeted energy efficiency and air pollution from many different angles, including vehicle, appliance, and building standards, tax credits, and now economywide emissions targets. While the approaches are diverse, most of these policies share the important objective of seeking to influence economic behavior in ways that limit adverse environmental consequences. Thus climate action policies seek to change behavior, which in turn alters economic structure by inducing agents to choose different technologies, goods and services, and other modalities of economic behavior.

To support the state's deliberations on GHG mitigation and other policy responses to climate change, the BEAR model was earlier applied to AB32 scenarios comprising over 40 component policies (see the Annex below). This is an extremely diverse set of initiatives, reflecting the complexity of the California economy and the sophistication of the initiatives themselves. The policies also vary greatly in their scale, and some will affect nearly every energy consumer while others are targeted a very narrowly defined economic activities. For the scenario work with BEAR, we relied then and continue to rely on policy definitions assembled by the California Air Resources Board (ARB). These are then implemented in our economic modeling framework in conjunction with a wide variety of data sources discussed in greater detail in Section 4 below.

Table SA 1: Recommended Climate Action Policies as of AB32 Passage (2006)

Strategy	Agency	Emissions Reductions MMTCO2e 2010	2020	Double Counted 2020	Anualized (2006$ in 2020) Cost	Saved
Vehicle Climate Change Standards	ARB	1	30		1,331	6,643
Diesel Anti-Idling	ARB	0.64	1.46		58	322
Other New Light Duty Vehicle Technologies	ARB	0	5.4		1,569	1,355
HFC Reduction Strategies	ARB	0	8.7		276	201
Transport Refrigeration Units (on and off road)	ARB	0.01	0.02		21	13
Shore Electrification	ARB	0.08	0.55		150	119
Manure Management	ARB	0	1		45	9
PFC Emission Reduction for Semiconductors	ARB	0.53	0.53		27	0
Alternative Fuels: Biodiesel Blends	ARB	0.4	0.8		0	0
Alternative Fuels: Ethanol	ARB	0.62	2.38		3,102	2,233
Heavy-Duty Vehicle Emission Reduction Measures	ARB	0	3.15		136	698
Venting and Leaks in Oil and Gas Systems	ARB	1	1		10	9
Hydrogen Highway	ARB					
Achieve 50% Statewide Recycling Goal	IWMB	3	3		82	0
Landfill Methane Capture	IWMB	0.89	2.66	0.86	61	171
Zero Waste - High Recycling	IWMB	0	3	0.00	180	111
Conservation Forest Management	Forestry	1	2.35		4	0
Forest Conservation	Forestry	0.4	0.4		15	0
Fuels Management/Biomass	Forestry	1.08	3.0	1.80	1,305	1,559

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Source: California Air Resources Board

After an empirical assessment of the CAT policies was included in CARB's initial Scoping Plan[2], the BEAR project has been involved for several months in a collaborative model comparison exercise with ARB. This activity involved comparison of results from BEAR, ARB's own EDRAM model, and the MRN-NEEM model developed by the Electric Power Research Institute (EPRI) and Charles Rivers Associates (EPRI:2007). The point of the exercise was to appraise California climate policy from a variety of perspectives, using the models most closely associated with various stakeholders in the policy process. To facilitate results comparison, ARB set forth a uniform set of policy scenarios, in each case involving a combination of the leading CAT policies and market oriented carbon cap measures that would be designed to make up the difference between CAT mitigation and the state's official goals for GHG reduction. These combinations are indicated in the first five scenarios defined in

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[2] Roland-Holst (2007a).

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Table SA 2 below.

Table SA 2: Scenarios Analyzed for the ARB Comparison Project

	Offsets	LCFS	Pavley II	VMT Reduction	EE Standards	33% RES	CHP	Annual EE Response
ARB1	4%	Full	Full	Full	Full	Full	Full	None
ARB2	No	Full	Full	Full	Full	Full	Full	None
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ARB4	4%	Full	Full	Full	Half	Excluded	Half	None
ARB5	4%	Half	Half	Excluded	Half	Excluded	Half	None
ARB_Cap	4%	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	None
EE1	4%	Full	Full	Full	Full	Full	Full	0.40%
WM1	Full	Full	Full	Full	Full	Full	Full	None

Table SA 3: Assumptions

	Component	Assumption
1	GHG Pollutants	CO2, CH4, N2O, SF6, PFC, and HFC
2	2020 Goal	15% below 2005 emissions
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9	WM	California is part of a Waxman-Markey national climate initiative (ACES)

The eight cases above represent the core policy packages assessed by the BEAR model. CARB evaluated the first five in their assessment, while CRA evaluated the first six.

1.1 Comparison Project Macroeconomic Results

For the scenarios discussed above, the BEAR macroeconomic assessment effects are presented in Table 1.1.1 below. A few salient results are immediately apparent. Firstly, the overall growth impact of the five ARB case versions of this ambitious climate policy package is each negligible, changing state real GSP by less than one percent annually by 2020 and real state employment by at most one half of one percent. When account is taken of innovation response or national climate initiative, employment in the state actually increases, as expenditures shift from imported energy dependence to demand for more labor-intensive in-state goods and services. Although we do not discuss the ARB results in detail here, quite small macro impacts are generally consistent across all the scenarios and indeed across the three model comparison contributions.

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Table 1.1.1: Aggregate Adjustments
(percent changes with respect to baseline values in 2020)

	1	2	3	4	5	6	7	8
	ARB1	ARB2	ARB3	ARB4	ARB5	ARB_Cap	EE1	WM1
Total GHG	-14	-19	-14	-14	-14	-14	-14	-9
Household GHG	-13	-13	0	-13	0	1	-13	-8
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Jobs (thousands)	-16	-18	-40	-56	-81	-101	397	73

NB: *Permit price in 2007 dollars per metric ton of CO2 equivalent carbon, in 2020.*

Even in cases where aggregate impacts (GSP) are growth negative, the magnitude is so small that it represents a few months of average baseline GSP growth. In other words, even in the worst case considered California can achieve a decade of climate objectives and realize the same aggregate wealth only about 5 months later, while achieving unprecedented mitigation of global warming pollution.

The presence of offsets in Scoping Plan policies has an ambiguous effect. When offsets are not allowed (Scenario ARB2) the growth cost is higher. When offsets are completely permissible in a national trading system, there is substantial growth. This flexibility may seem attractive, but offsets are not the main driver of growth in Scenario 8. In any case, it must be remembered that offsets deny the state mitigation potential for other co-pollutants, including criteria toxics. Furthermore, extensive recourse to offsets averts innovation opportunities for California entrepreneurs, locally and, with technologies incubated in California, in the next break-out knowledge intensive industry. Energy is by revenue the world's largest industry, and energy efficiency can be to that industry what IT was to management, revolutionizing traditional practices around the world. One of the primary benefits of AB32 could be induced innovation, allowing California businesses to capture the momentum of an explosive emerging global market.

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It is worth noting that other findings have suggested larger growth costs from climate action policies. The main reason for this, as we interpret our own and alternative analysis, is failure to incorporate the many positive economic stimuli associated with the AB32 policy package. This included significant new demand for construction, technology, natural gas, and other

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components of a structural transition to greater energy efficiency and green modernization of the state economy.[3]

Emissions adjustments are generally what would be mandated by the component policies themselves, although they can vary in the BEAR model because emission levels are endogenous. This happens for three reasons:

Policy interaction – In some cases, policies have interactive direct and indirect effects. The former will be deterministic ex ante, and are simply additive. The latter can be quite complex and require detailed inspection to identify positive and negative synergies.

Technical substitution – The current scenarios do not take account of the widely perceived potential for climate policies to induce innovation, but BEAR model does allow for technical substitution. In response to price changes, individual sectors a can be expected to substitute fuels, other inputs, and/or factors of productions to achieve greater cost effectiveness.

Indirect price effects – Sometimes referred to as rebound effects, these price responses will create a second round of demand adjustments in sectors with significant price changes. In the case of fuels, for example, falling demand may be somewhat offset by induced price declines. Likewise, rising demand for construction services may be partially attenuated by price increases.

Relevant examples of these effects include transport intensive service sectors, like Ground Transport (GndTns) and Wholesale and Retail Trade (WhlTrad). Both sectors experience significant emissions reductions because they are impacted by many components of the AB32 policies, yet rising service sector demand offsets any negative output and employment effects for them. This is a combined result of policy interaction and substitution effects, and is typical of the structural transition benefits captured by BEAR. A partial equilibrium analysis of the individual direct industry policy effects would not identify these offsetting gains, yet though they accrue directly to AB32 targeted sectors and require no redistribution or compensatory measures and yield a net benefit.

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[3] Other findings also focus on subjective welfare measures including inconvenience or disutility associated with technical change. We believe these behavioral parameters are open to question and focus our results on the real side of the economy: real output, incomes, and job growth.

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The Cement sector is another prime example, where possible adverse consequences of AB32 emissions targeting are more than offset by induced construction demand arising from other AB32 policies. These examples highlight the importance of understanding the AB32 policies as an integrated package of climate action measures, of seeing both supply and demand side effects, linkages between policy components, and induced market effects. During the implementation process, policy dialogue often decomposed among stakeholder interests, and these integrated economic effects can be overlooked. These results demonstrate the essential contributions policies can make to each other, and the importance of a more comprehensive approach to assessment, design, and implementation.

1.2 General Results Interpretation

The macroeconomic results of the core scenarios ARB1-5 have been discussed above. In this section, a few general observations are offered from the perspective of current and previous research with the BEAR model.

1.2.1 *Aggregate Real Effects on the Economy are Small (Growth is not Threatened)*

Despite the political and economic importance of state's climate policy initiatives, the economic burden of the proposed policies is small relative to the California economy. To take two examples, in Scenario 1 the approximate cost of all permits would be less than 2% of the value of output in the target sectors, and a much smaller fraction of state GDP. In a more extreme case, when AB32 attains only half its target mitigation and C&T makes up the difference in only three sectors (Scenario 9), the permit cost is much higher (about 24% of three-sector output value), but still less than 2% of state GDP. To the extent that the sectoral costs are passed on, they cannot significantly reduce aggregate state income and consumption. In particular, they are much smaller than most climate damage estimates.

1.2.2 *Individual Sector Demand, Output, and Employment can Change Significantly (Economic Structure Changes)*

Energy fuel and carbon capped sectors can experience important adjustments, but these are offset by expansion elsewhere, including Services, Construction, and Consumer goods. The California economy is seen undergoing an important structural adjustment, reducing aggregate energy intensity and increasing the labor-intensity of state demand and output. These shifts, masked at the aggregate level, may present opportunities for policy makers to mitigate adjustment costs.

In other words, the aggregate results indicate that the policies considered will pose no significant net cost to the California economy. They might raise costs for some firms and individuals, but as a whole the California economy will probably experience higher growth and create more jobs than it would have without this action (even before considering climate damage aversion). The task for California policymakers in the near term will be to design policies that fairly and efficiently distribute the costs of reducing greenhouse gas emissions.

1.2.3 Combined Effects of the Climate Action Policy Packages have Net Effects On Individual Sectors that Cannot be Identified in Sector-specific Policy Analysis

Because of general equilibrium effects, including policy interaction, technical and expenditure substitution, price (e.g. rebound effects), the effects of individual climate policies on individual sectors can be partially or completely reversed. For this reason, it is essential to assess design and implementation of climate policies in an integrated manner to avoid misleading interpretation of direct effects or disarticulation of the policy dialogue. As a case in point, in the Cement sector, any adverse direct effects of new emission regulations are more than offset by new construction demand that is induced by other climate action measures.

1.2.4 Employment Effects are Positive when Innovation Potential is Realized, or when California Joins a National Climate Initiative

The reason for this, as in past BEAR estimates, is re-direction of consumer expenditure from energy/fuels to more labor-intensive goods and services. This is one of the most important economic effects of climate action policy, reducing import dependence on capital-intensive fuels and increasing spending on in-state goods and services. Joining a national climate initiative reduces abatement costs for California and increases its innovation opportunities.

1.2.5 No Significant Leakage is Observed in the BEAR Scenarios

Import and export adjustments are significant in some sectors, but exhibit no discernable interaction with the carbon constraint in the capped sectors. Imports of fuels far sharply as the policies dictate, but there is negligible evidence of pollution outsourcing in targeted or energy dependent sectors.

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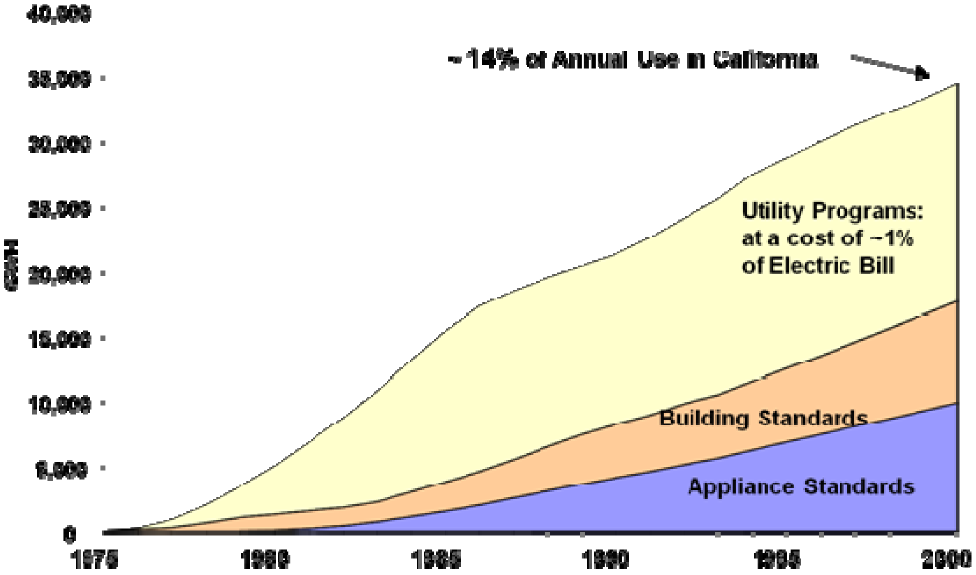
1.2.6 *No Forgone Damages are taken into Account*

For all scenarios, we have omitted consideration of this important class of policy benefits, including foregone local pollution and attendant public health cost savings. Over a thirteen year time horizon, and considering the amount of pollution reduction, these benefits could be significant (see e.g. Stern: 2006).

1.3 The Role of Innovation

An important characteristic of the current AB32 and the ARB/CRA scenarios is technological neutrality. This means that factor productivity, energy use intensities, and other innovation characteristics were held constant across cap and trade scenarios. Energy use and pollution levels might change, but the prospect of innovation to reduce energy intensity was not considered. This consideration is important for two reasons. Technological change in favor of energy efficiency has been a hallmark of California's economic growth experience over the last four decades. Over this period California has reduced its aggregate energy intensity by about 1.5% per year, attaining levels that today are 40% below the national average. Moreover, most observers credit this technological progress to California's energy/climate policies, combinations of mandated and incentive based efficiency measures from which the Climate Action Team recommendations are direct descendants.

Figure 1.3.1: Household Savings from Energy Efficiency Measures



Source: Rosenfeld (2008)

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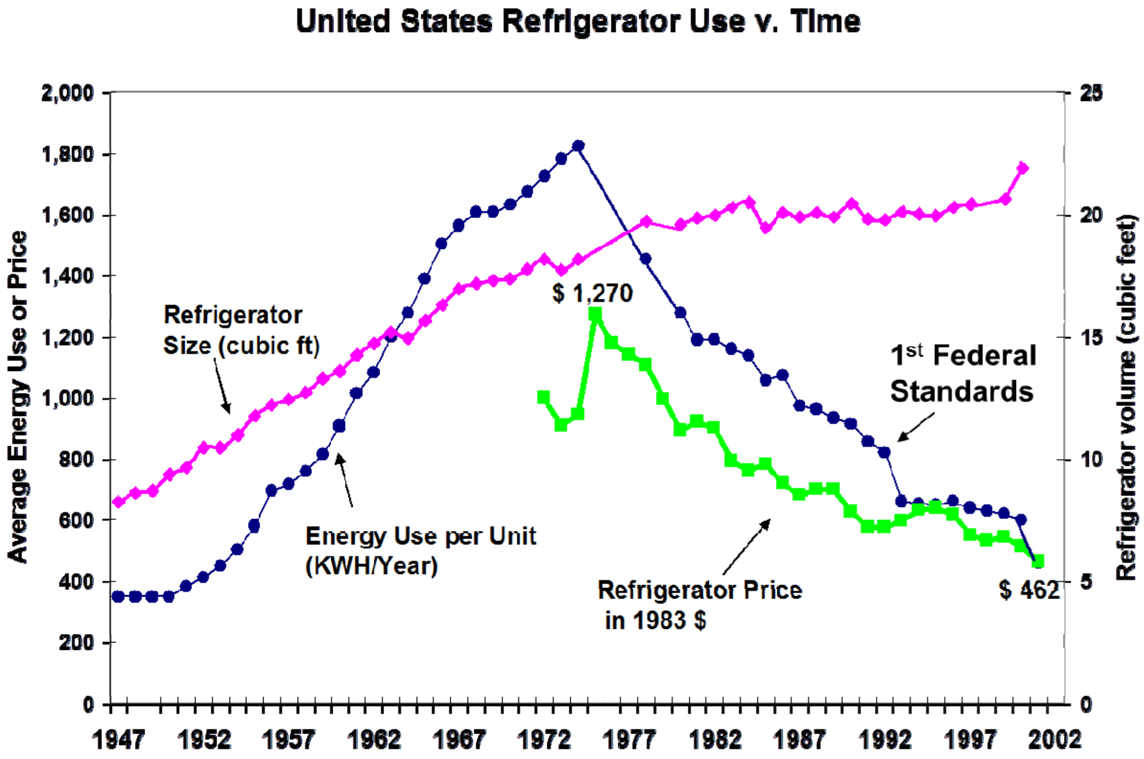
Thus, energy innovation has been part of the history of the state's economic growth and at the same time a consequence of its policies. As

Figure 1.3.1 clearly shows, since the early 1970's California households have saved billions from a combination of standards for appliances, efficiency oriented building codes, and incentive programs to decouple utility profits from conventional energy sales. A second primary response to standards was induced innovation for efficiency in appliances, typified by refrigerators in Figure 1.3.2. Not only did energy efficiency sharply increase with standards, but capacity remained high and prices fell nearly continuously. Because of it's size, California also set the de facto national standard for appliance producers, and the later application of national appliance efficiency standards had a small incremental effect because manufacturers already met or exceeded California standards, a precedence benefit often overlooked in the AB32 dialog.

Figure 1.3.2: Induced Innovation in Refrigerator Technology



Source: Rosenfeld (2008)

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For these reasons, it is important to consider the potential contribution of continued innovation to the economic effects of California climate policy. For illustrative purposes, we used the BEAR model for two comparison cases to illustrate what innovation could contribute to the economic impact estimates already discussed.

If climate action measures continue to improve efficiency, particularly if this improvement is distributed across all sectors of the economy, it could contribute 3% additional real GSP by 2020, increase statewide employment by over 2%, and raise real per capita incomes by nearly $1,400 per year. All these results are significantly more dynamic than the technology neutral scenarios, yet California's innovation potential is one of its most robust economic characteristics.

Although these results are best interpreted as indicative, they have two important implications for the state's climate policy research agenda. Firstly, even the modest assumptions about innovation show it has significant potential to make climate action a dynamic growth experience for the state economy. Second, the size and distribution of potential growth benefits is large enough to justify significant commitments to deeper empirical research on these questions.

If the state is to maintain its leadership as a dynamic and innovation oriented economy, it may be essential for Climate Action for policy to include explicit incentives for competitive innovation, investing in discovery and adoption of new technologies that offer win-win solutions to the challenge posed by climate change for the state's industries and for consumers. In this way, California can sustain its enormous economic potential and establish global leadership in the world's most promising new technology sector, energy efficiency and pollution reduction, as it has done so successfully in IT and biotechnology.

1.4 Economic Behavior and Structural Adjustment

To understand induced adjustments, we focus on a triad of behavioral elements (

Figure 1.3.1): Household consumption/adoption, Firm investment/adoption, Firm price setting. Consider a cap and trade policy that imposes a ceiling on GHG emissions, allowing firms to buy permits if they exceed their initial allowances. If the ceiling is binding, the policy gives rise to

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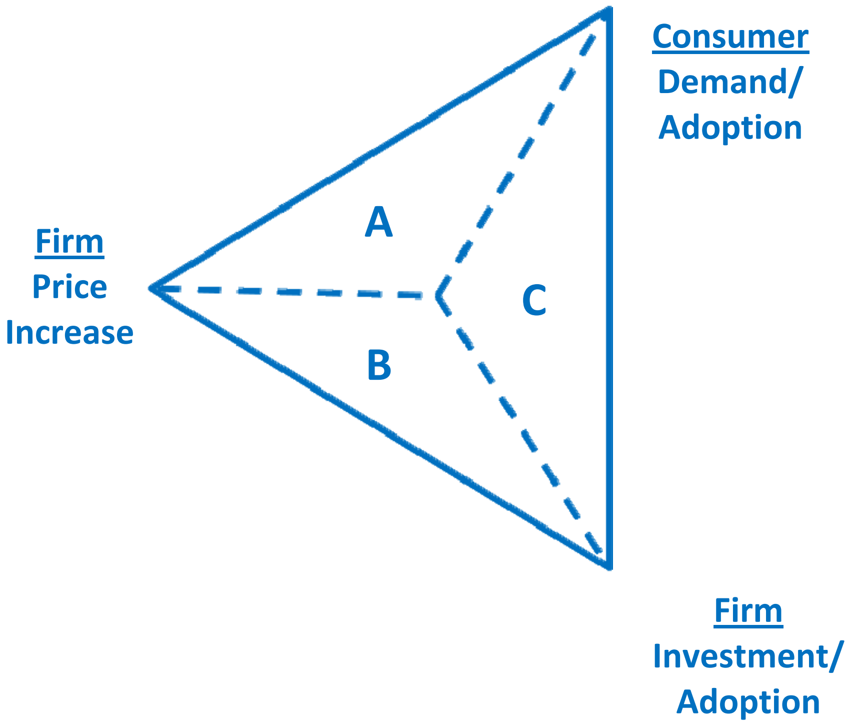
a new cost in the economy, having created a market for a negative externality. What this represents is the cost of re-allocating pollution rights that were until now unpriced. In response to the new cost, firms have two options, to increase prices or efficiency levels. In the first case, the firm must have sufficient market power to pass through the cost to prices paid by downstream buyers of their product. The second option requires firms to invest in technology adoption that will reduce emissions, increase profits, or both, to offset the new cost. In general, it is reasonable to expect an industry to adapt with a combination of price and investment/adoption responses, but this depends on market conditions and technology choices.

The third corner of the triad, consumers, would respond in the event of a price increase for the good or service in question, or if product standards were mandated to them. In these cases, they too face an investment/adoption decision, the prospect of incurring a fixed up-front cost to reduce long term dependence on a more expensive commodity. Their willingness and ability to do this will depend on the (long term) credibility of the price adjustment or policy, their purchasing power, and technology choices available to them.

Figure 1.4.1: The Policy Response Triad



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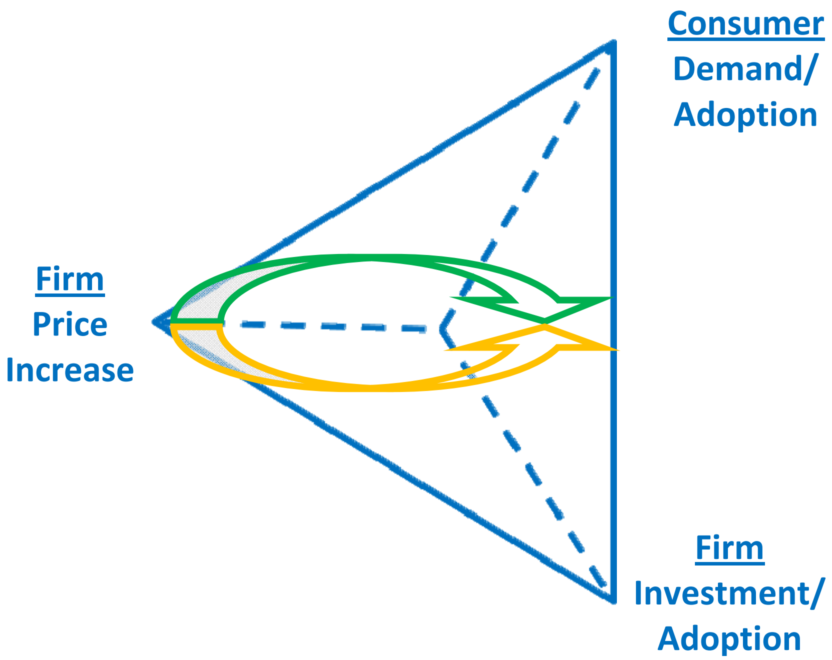
Within the universe of policy responses, the three areas A, B, and C represent fundamentally different adjustment mechanisms. In region B, firms absorb most of the adjustment with a combination of price increases and investments in more efficient technology. Households are relatively insensitive to the price changes, and their demand patterns change relatively little, as was the case, for example, with recent oil price increases and rising home construction costs over the recent low interest rate cycle. In circumstances like this, demand driven sectors like electricity, refined petroleum, and cement are more likely to maintain stable output trends and long term profitability, largely through passing on increased cost (left side of region B), efficiency improvements (right side) and combinations of these. Because, for the first-tier emitting industries, GHG efficiency is largely about energy efficiency, the long term savings for firms from technology adoption could be substantial if energy prices trend higher. In this context, cap and trade policies promise a double dividend.

Figure 1.4.2: Structural Transition



Sections A and C imply more significant demand side adjustment, with more uncertain effects on statewide output, employment, and incomes. To the extent that households adopt efficiency improving technologies (cars, appliances, etc.), they can offset rising prices (A) or actually save money (C) to stimulate other forms of consumption. In the AB32 scenario analysis (Roland-Holst:2006A), for example, induced household efficiency gains from mandatory standards (e.g. Pavley) produced significant personal energy savings. These were then reallocated to other consumption and, because this was more likely to be on in-state goods and services, GSP and state employment were stimulated.

Ultimately, all three components of structural adjustment will come into play. Generally speaking, the short run responses will be instigated by firms, since they are the original targets of the policy. Their first response, to the extent markets permit, will be to raise prices. As time passes, they will migrate (Figure 1.4.2, yellow arrow) toward new technology that enables their industry to return to competitiveness. This process, enshrined in the economic theories of competition, will arise from a combination of firm entry and adoption by incumbents to compete against or even deter such entrants. The speed by which competitive conditions are restored depends critically on the initial competitive conditions. If markets are too concentrated or entry barriers too high, this component of structural transition could proceed very slowly.

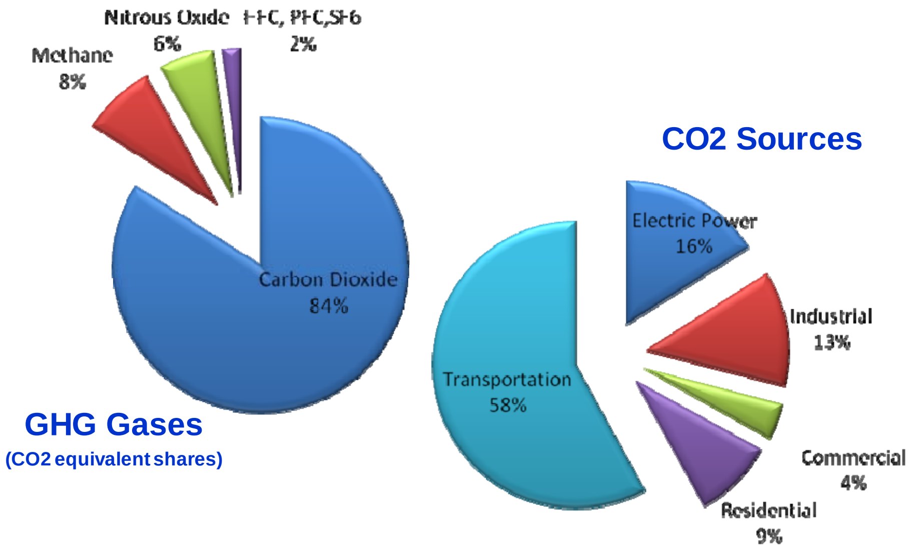
Meanwhile, consumers will respond to the initial price increase in two stages. In the short term, they can be expected to engage in demand smoothing, absorbing higher prices temporarily to prevent sudden changes in lifestyle. If price changes persist, however, this will be followed by decisions to change consumption patterns, including adoption of technologies that reduce dependence on higher priced goods (Figure 1.4.2, green arrow). The combination of these two trends yields the basic structural transition arising from cap and trade, the introduction of new private costs that more fully account for public costs of climate change risk.

1.5 Induced Price Effects

To what extent can firms pass on the cost of regulation? This depends almost completely on the degree of their market power, sometimes called monopoly power. Clearly firms have a strong incentive to do this, since it would be a most economical way of neutralizing regulatory cost with no changes in operations or management practices. Of course their ultimate profit and output conditions are unlikely to remain neutral, since consumers will react in some way to a price pass through.

In any case, history can give us some guidance about pass through from production costs to prices even if the information is only inferential. In the cement industry, as in most emission-intensive industries, energy costs are a prominent or even dominant cost of production. This is quite apparent at the aggregate level in California (Figure 1.5.1), where we see that CO2 dominates GHG emissions and is itself a result of using carbon energy technologies for transportation, electricity production, heating, etc.

Figure 1.5.1: Greenhouse Gases and Energy Use in California



When energy prices increase, the market power of these firms is tested in their ability to pass along the cost increases, “sterilizing” an adverse profit effect. In the case of cement, natural gas is the dominant fuel source, and we can examine the historical correlation between LNG prices and cement prices for inference about the potential for pass through. Figure 1.5.2 plots the two variables against each other over the period 1970-2000, and a strong positive correlation is readily apparent.

To characterize this relationship more precisely, we regressed Cement prices against LNG prices, both in logarithmic form, and the results are presented in Table 1.5.1 summarizes the results. The relevant estimate is labeled the Coefficient of the X variable, which in this case denotes the historical elasticity of Cement prices with respect to LNG prices. This estimate indicates that, in percentage terms, Cement prices have risen at about half the rate of LNG

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prices over time. This percentage is larger than LNG's cost share in Cement production, and significantly so. Thus it appears that, were other conditions to remain constant over the period considered, Cement producers would be able to offset most or all energy price increases by passing them on to consumers. We know, however, that other cost components in Cement have risen steadily over time, so this elasticity is an over-estimate of LNG price effects on the sector under consideration. We still concluded, however, that a significant degree of market power and pass through is possible in this sector.

Figure 1.5.2: National Cement and LNG Prices, 1970-2000

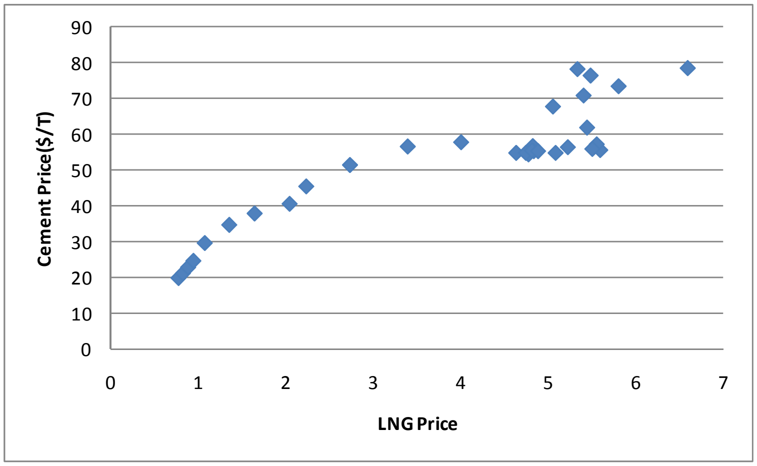


Table 1.5.1: Cost Price Elasticities for LNG and Cement, 1970-2000

Regression Statistics	
Multiple R	0.96
R Square	0.91
Adjusted R	0.91
Standard E	0.05
Observatio	31

ANOVA

	df	*SS*	*MS*	*F*
Regressio	1	0.77	0.77	308.45
Residual	29	0.07	0.00	
Total	30	0.84		

	Coefficients	*andard Err*	*t Stat*	*P-value*
Intercept	1.42	0.02	79.13	0.00
X Variable	0.53	0.03	17.56	0.00

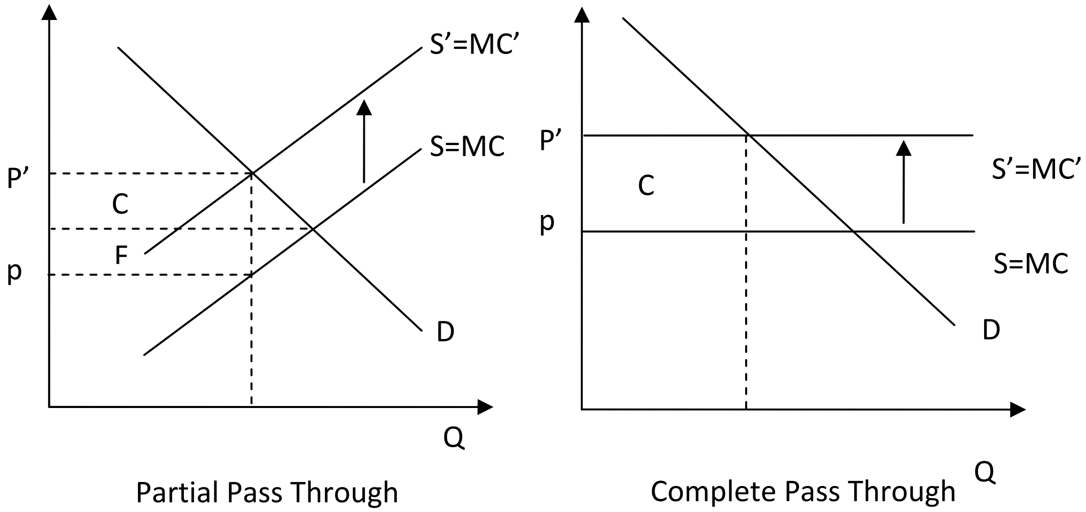
Elasticity estimation supports an empirical argument for cost pass through, but economic theory describes it as the result of combined supply and demand conditions. To compare this perspective, consider the examples in Figure 1.5.3 below, which depict supply and demand curves in the presence of a fixed increase to industry marginal cost (MC->MC'). When the supply curve on the right shifts upward, consumers and firms share the burden of increased cost (areas C and F). On the other hand, when supply is demand driven and highly elastic, as on the left, consumers bear all the increased cost.

Using the case of the Cement industry again, Figure 1.5.4 plots national output against inflation adjusted prices over the thirty year period 1970-2000. These figures suggest very strongly that Cement is a demand driven industry, and that the incidence of cost shocks can be passed on to consumers.

Thus we see from two perspectives that cost pass through to prices can occur, at least in the short run. In the face of process related cost shocks such as GHG regulation then, it is reasonable to expect firms to increase prices until they can make the efficiency improvements needed to return to competitiveness. Consumers will then react according to their short run demand elasticity. This could mean they are unresponsive in the short run, either because the price increase is not credible in the long term or they want to smooth consumption while planning technology adoption. In the longer term, if prices remain high they will contribute to structural transition by shifting consumption away through increased efficiency or substitution. Meanwhile, competitive firms will be shifting industry technology through their own structural transition, including firm entry, exit, and incumbent investments in more efficient technology. As the fixed costs of these investments and disinvestments are made, industry average costs will come back down toward a longer term equilibrium value, and some demand will be restored.

In a world of innovation and efficient capital markets, this structural transition can happen in a matter of a few years. If cap and trade policies are phased to take account of this, the adjustment process can be relatively smooth. For all this to work, both stakeholders and policy makers need reliable information about all these adjustment components. In this section, we use scenario analysis with the BEAR model to give indications about the magnitude and incidence patterns of structural transition, as it would arise from a cap and trade GHG mitigation regime.

Figure 1.5.3: Cost Pass Through under Alternative Supply Conditions



Partial Pass Through

Complete Pass Through

Figure 1.5.4: Cement Industry Supply, 1970-2000

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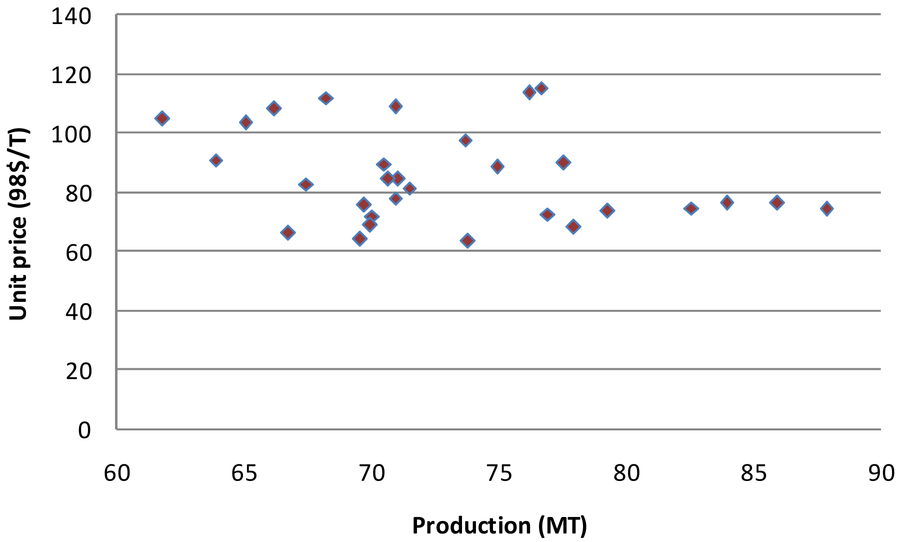

OVERVIEW OF THE BEAR MODEL

The Berkeley Energy and Resources (BEAR) model is in reality a constellation of research tools designed to elucidate economy-environment linkages in California. The schematics in Figure 1.4.1 and Figure 1.4.2 describe the four generic components of the modeling facility and their interactions. This section provides a brief summary of the formal structure of the BEAR model.[4] For the purposes of this report, the 2003 California Social Accounting Matrix (SAM), was aggregated along certain dimensions. The current version of the model includes 50 activity sectors and ten households aggregated from the original California SAM. The equations of the model are completely documented elsewhere (Roland-Holst: 2005), and for the present we only discuss its salient structural components.

1.6 Structure of the CGE Model

Technically, a CGE model is a system of simultaneous equations that simulate price-directed interactions between firms and households in commodity and factor markets. The role of government, capital markets, and other trading partners are also specified, with varying

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[4] See Roland-Holst (2005) for a complete model description.

degrees of detail and passivity, to close the model and account for economywide resource allocation, production, and income determination.

The role of markets is to mediate exchange, usually with a flexible system of prices, the most important endogenous variables in a typical CGE model. As in a real market economy, commodity and factor price changes induce changes in the level and composition of supply and demand, production and income, and the remaining endogenous variables in the system. In CGE models, an equation system is solved for prices that correspond to equilibrium in markets and satisfy the accounting identities governing economic behavior. If such a system is precisely specified, equilibrium always exists and such a consistent model can be calibrated to a base period data set. The resulting calibrated general equilibrium model is then used to simulate the economywide (and regional) effects of alternative policies or external events.

The distinguishing feature of a general equilibrium model, applied or theoretical, is its closed-form specification of all activities in the economic system under study. This can be contrasted with more traditional partial equilibrium analysis, where linkages to other domestic markets and agents are deliberately excluded from consideration. A large and growing body of evidence suggests that indirect effects (e.g., upstream and downstream production linkages) arising from policy changes are not only substantial, but may in some cases even outweigh direct effects. Only a model that consistently specifies economywide interactions can fully assess the implications of economic policies or business strategies. In a multi-country model like the one used in this study, indirect effects include the trade linkages between countries and regions which themselves can have policy implications.

The model we use for this work has been constructed according to generally accepted specification standards, implemented in the GAMS programming language, and calibrated to the new California SAM estimated for the year 2003.[5] The result is a single economy model calibrated over the fifteen-year time path from 2005 to 2020.[6] Using the very detailed accounts of the California SAM, we include the following in the present model:

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[5] See e.g. Meeraus et al (1992) for GAMS. Berck et al (2004) for discussion of the California SAM.

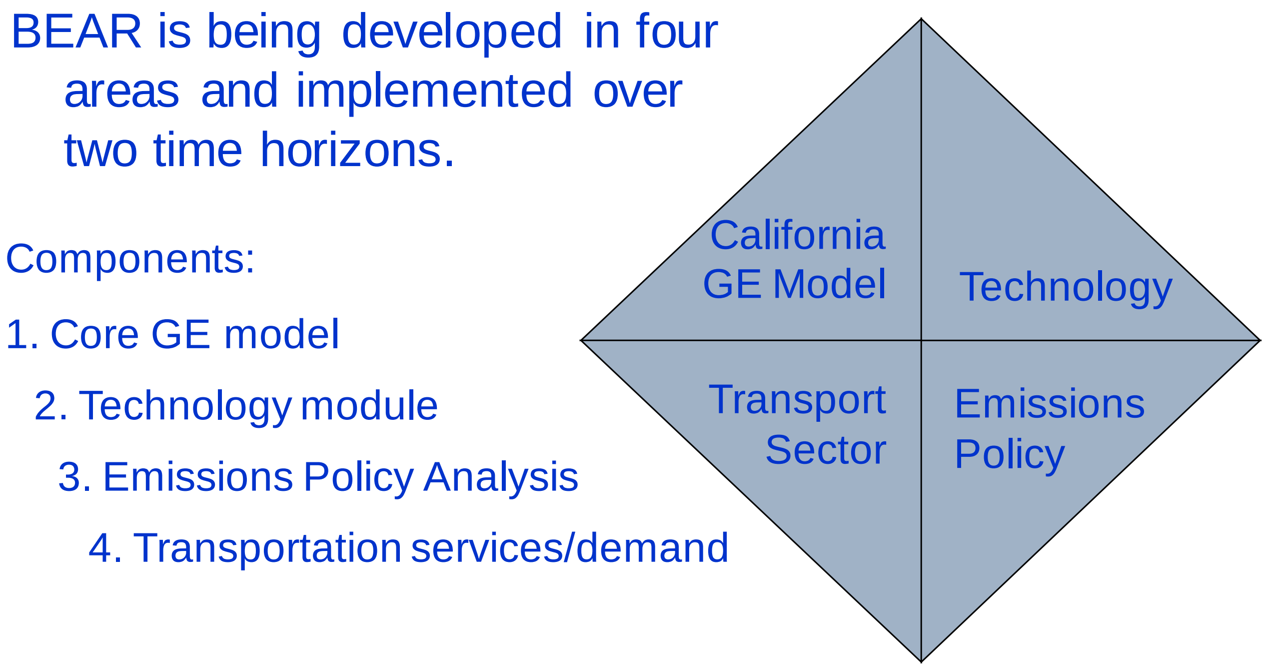
[6] The present specification is one of the most advanced examples of this empirical method, already applied to over 50 individual countries or combinations thereof.

1.7 Production

All sectors are assumed to operate under constant returns to scale and cost optimization. Production technology is modeled by a nesting of constant-elasticity-of-substitution (CES) functions.See Figure 1.10.1 for a schematic diagram of the nesting.

In each period, the supply of primary factors — capital, land, and labor — is usually predetermined.[7] The model includes adjustment rigidities. An important feature is the distinction between old and new capital goods. In addition, capital is assumed to be partially mobile, reflecting differences in the marketability of capital goods across sectors.[8] Once the optimal combination of inputs is determined, sectoral output prices are calculated assuming competitive supply conditions in all markets.

Figure 1.7.1: Component Structure of the Modeling Facility



BEAR is being developed in four areas and implemented over two time horizons.

Components:

1. Core GE model
2. Technology module
3. Emissions Policy Analysis
4. Transportation services/demand

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[7] Capital supply is to some extent influenced by the current period's level of investment.

[8] For simplicity, it is assumed that old capital goods supplied in second-hand markets and new capital goods are homogeneous. This formulation makes it possible to introduce downward rigidities in the adjustment of capital without increasing excessively the number of equilibrium prices to be determined by the model.

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1.8 Consumption and Closure Rule

All income generated by economic activity is assumed to be distributed to consumers. Each representative consumer allocates optimally his/her disposable income among the different commodities and saving. The consumption/saving decision is completely static: saving is treated as a "good" and its amount is determined simultaneously with the demand for the other commodities, the price of saving being set arbitrarily equal to the average price of consumer goods.

The government collects income taxes, indirect taxes on intermediate inputs, outputs and consumer expenditures. The default closure of the model assumes that the government deficit/saving is exogenously specified.[9] The indirect tax schedule will shift to accommodate any changes in the balance between government revenues and government expenditures.

The current account surplus (deficit) is fixed in nominal terms. The counterpart of this imbalance is a net outflow (inflow) of capital, which is subtracted (added to) the domestic flow of saving. In each period, the model equates gross investment to net saving (equal to the sum of saving by households, the net budget position of the government and foreign capital inflows). This particular closure rule implies that investment is driven by saving.

1.9 Trade

Goods are assumed to be differentiated by region of origin. In other words, goods classified in the same sector are different according to whether they are produced domestically or imported. This assumption is frequently known as the *Armington* assumption. The degree of substitutability, as well as the import penetration shares are allowed to vary across commodities. The model assumes a single Armington agent. This strong assumption implies that the propensity to import and the degree of substitutability between domestic and imported goods is uniform across economic agents. This assumption reduces tremendously the dimensionality of the model. In many cases this assumption is imposed by the data. A symmetric assumption is made on the export side where domestic producers are assumed to

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[9] In the reference simulation, the real government fiscal balance converges (linearly) towards 0 by the final period of the simulation.

differentiate the domestic market and the export market. This is modeled using a *Constant-Elasticity-of-Transformation* (CET) function.

1.10 Dynamic Features and Calibration

The current version of the model has a simple recursive dynamic structure as agents are assumed to be myopic and to base their decisions on static expectations about prices and quantities. Dynamics in the model originate in three sources: i) accumulation of productive capital and labor growth; ii) shifts in production technology; and iii) the putty/semi-putty specification of technology.

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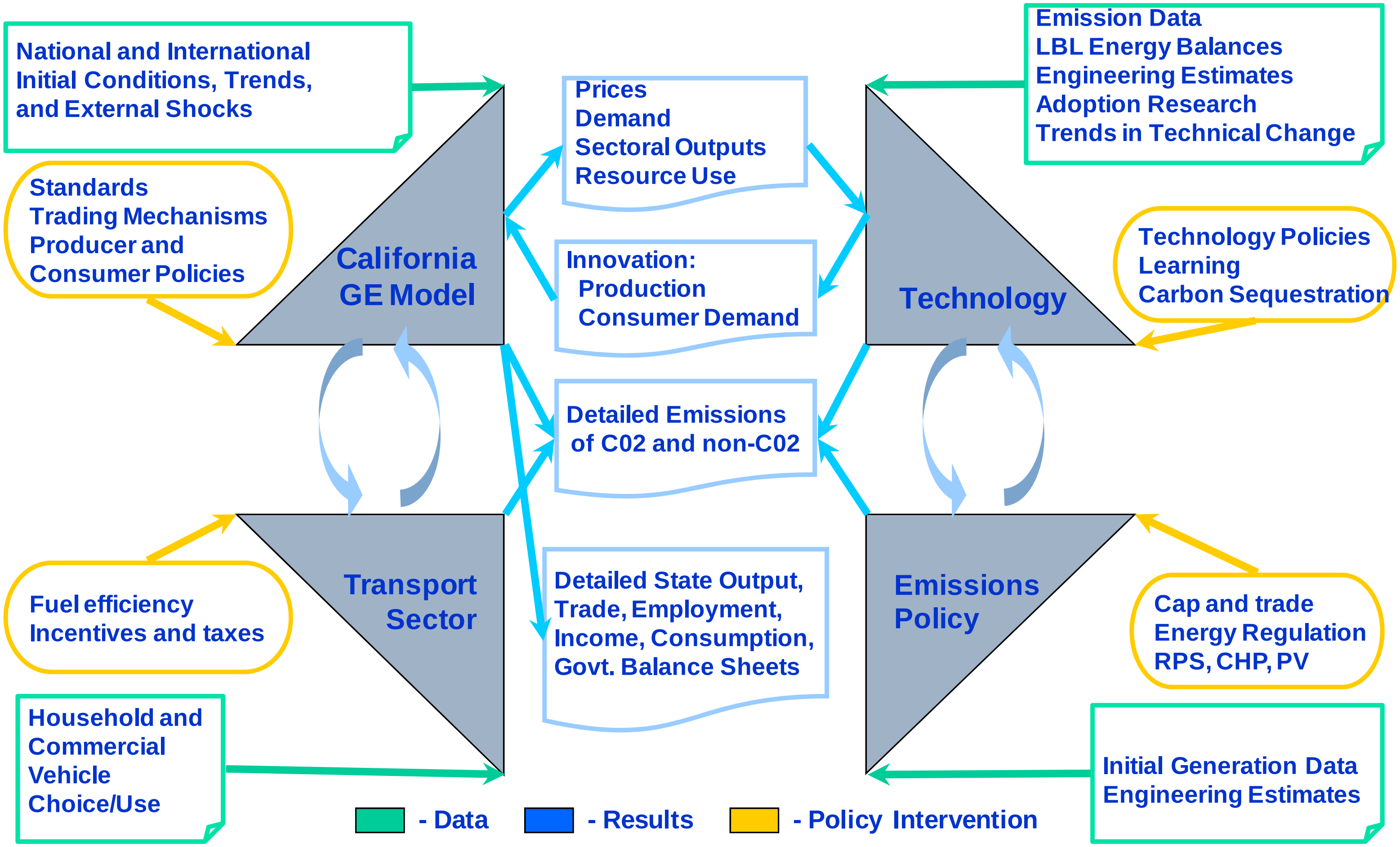
Figure 1.10.1: Schematic Linkage between Model Components



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1.11 Capital accumulation

In the aggregate, the basic capital accumulation function equates the current capital stock to the depreciated stock inherited from the previous period plus gross investment. However, at the sectoral level, the specific accumulation functions may differ because the demand for (old and new) capital can be less than the depreciated stock of old capital. In this case, the sector contracts over time by releasing old capital goods. Consequently, in each period, the new capital vintage available to expanding industries is equal to the sum of disinvested capital in contracting industries plus total saving generated by the economy, consistent with the closure rule of the model.

1.12 The putty/semi-putty specification

The substitution possibilities among production factors are assumed to be higher with the new than the old capital vintages — technology has a putty/semi-putty specification. Hence, when a shock to relative prices occurs (e.g. the imposition of an emissions fee), the demands for production factors adjust gradually to the long-run optimum because the substitution effects are delayed over time. The adjustment path depends on the values of the short-run elasticities of substitution and the replacement rate of capital. As the latter determines the pace at which new vintages are installed, the larger is the volume of new investment, the greater the possibility to achieve the long-run total amount of substitution among production factors.

1.13 Dynamic calibration

The model is calibrated on exogenous growth rates of population, labor force, and GDP. In the so-called Baseline scenario, the dynamics are calibrated in each region by imposing the assumption of a balanced growth path. This implies that the ratio between labor and capital (in efficiency units) is held constant over time.[10] When alternative scenarios around the baseline are simulated, the technical efficiency parameter is held constant, and the growth of capital is endogenously determined by the saving/investment relation.

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[10] This involves computing in each period a measure of Harrod-neutral technical progress in the capital-labor bundle as a residual. This is a standard calibration procedure in dynamic CGE modeling.

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1.14 Modelling Emissions

The BEAR model captures emissions from production activities in agriculture, industry, and services, as well as in final demand and use of final goods (e.g. appliances and autos). This is done by calibrating emission functions to each of these activities that vary depending upon the emission intensity of the inputs used for the activity in question. We model both CO2 and the other primary greenhouse gases, which are converted to CO2 equivalent. Following standards set in the research literature, emissions in production are modeled as factors inputs. The base version of the model does not have a full representation of emission reduction or abatement. Emissions abatement occurs by substituting additional labor or capital for emissions when an emissions tax is applied. This is an accepted modeling practice, although in specific instances it may either understate or overstate actual emissions reduction potential.[11] In this framework, mission levels have an underlying monotone relationship with production levels, but can be reduced by increasing use of other, productive factors such as capital and labor. The latter represent investments in lower intensity technologies, process cleaning activities, etc. An overall calibration procedure fits observed intensity levels to baseline activity and other factor/resource use levels. In some of the policy simulations we evaluate sectoral emission reduction scenarios, using specific cost and emission reduction factors, based on our earlier analysis (Hanemann and Farrell: 2006).

The model has the capacity to track 13 categories of individual pollutants and consolidated emission indexes, each of which is listed in Table 1.14.1 below. Our focus in the current study is the emission of CO2 and other greenhouse gases, but the other effluents are of relevance to a variety of environmental policy issues. For more detail, please consult the full model documentation.

An essential characteristic of the BEAR approach to emissions modeling is endogeniety. Contrary to assertions made elsewhere (Stavins et al:2007), the BEAR model permits emission rates by sector and input to be exogenous or endogenous, and in either case the level of emissions from the sector in question is endogenous unless a cap is imposed. This feature is essential to capture structural adjustments arising from market based climate policies, as well as the effects of technological change.

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[11] See e.g. Babiker et al (2001) for details on a standard implementation of this approach.

Table 1.14.1: Emission Categories

Air Pollutants		
1.	Suspended particulates	PART
2.	Sulfur dioxide (SO_2)	SO2
3.	Nitrogen dioxide (NO_2)	NO2
4.	Volatile organic compounds	VOC
5.	Carbon monoxide (CO)	CO
6.	Toxic air index	TOXAIR
7.	Biological air index	BIOAIR
Water Pollutants		
8.	Biochemical oxygen demand	BOD
9.	Total suspended solids	TSS
10.	Toxic water index	TOXWAT
11.	Biological water index	BIOWAT
Land Pollutants		
12.	Toxic land index	TOXSOL
13.	Biological land index	BIOSOL

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Table 1.14.2: **California SAM for 2000 – Structural Characteristics**

1. 124 production activities
2. 124 commodities (includes trade and transport margins)
3. 3 factors of production
4. 2 labor categories
5. Capital
6. Land
7. 10 Household types, defined by income tax bracket
8. Enterprises
9. Federal Government (7 fiscal accounts)
10. State Government (27 fiscal accounts)
11. Local Government (11 fiscal accounts)
12. Consolidated capital account
13. External Trade Account

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Table 1.14.3: Aggregate Accounts for the Prototype California CGE

1. 50 Production Sectors and Commodity Groups

Sectoring Scheme for the BEAR Model

The following sectors are aggregated from a new, 199 sector California SAM

	Label	Description
1	A01Agric	Agriculture
2	A02Cattle	Cattle and Feedlots
3	A03Dairy	Dairy Cattle and Milk Production
4	A04Forest	Forestry, Fishery, Mining, Quarrying
5	A05OilGas	Oil and Gas Extraction
6	A06OthPrim	Other Primary Products
7	A07DistElec	Generation and Distribution of Electricity
8	A08DistGas	Natural Gas Distribution
9	A09DistOth	Water, Sewage, Steam
10	A10ConRes	Residential Construction
11	A11ConNRes	Non-Residential Construction
12	A12Constr	Construction
13	A13FoodPrc	Food Processing
14	A14TxtAprl	Textiles and Apparel
15	A15WoodPlp	Wood, Pulp, and Paper
16	A16PapPrnt	Printing and Publishing
17	A17OilRef	Oil Refining
18	A18Chemicl	Chemicals
19	A19Pharma	Pharmaceutical Manufacturing
20	A20Cement	Cement
21	A21Metal	Metal Manufacture and Fabrication
22	A22Aluminm	Aliminium
23	A23Machnry	General Machinery
24	A24AirCon	Air Conditioning and Refridgeration
25	A25SemiCon	Semi-conductor and Other Computer Manufacturing
26	A26ElecApp	Electrical Appliances
27	A27Autos	Automobiles and Light Trucks
28	A28OthVeh	Vehicle Manufacturing
29	A29AeroMfg	Aeroplane and Aerospace Manufacturing
30	A30OthInd	Other Industry
31	A31WhlTrad	Wholesale Trade
32	A32RetVeh	Retail Vehicle Sales and Service
33	A33AirTrns	Air Transport Services
34	A34GndTrns	Ground Transport Services
35	A35WatTrns	Water Transport Services
36	A36TrkTrns	Truck Transport Services
37	A37PubTrns	Public Transport Services
38	A38RetAppl	Retail Electronics
39	A39RetGen	Retail General Merchandise
40	A40InfCom	Information and Communication Services
41	A41FinServ	Financial Services
42	A42OthProf	Other Professional Services
43	A43BusServ	Business Services
44	A44WstServ	Waste Services
45	A45LandFill	Landfill Services
46	A46Educatn	Educational Services
47	A47Medicin	Medical Services
48	A48Recratn	Recreation Services
49	A49HotRest	Hotel and Restaurant Services
50	A50OthPrSv	Other Private Services

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2. Labor Categories

    1. Skilled

    2. Unskilled

B. Capital
C. Land
D. Natural Resources
E. 8 Household Groups (by income
    1. HOUS0 (<$0k)
    2. HOUS1 ($0-12k)
    3. HOUS2 ($12-28k)
    4. HOUS4 ($28-40k)
    5. HOUS6 ($40-60k)
    6. HOUS8 ($60-80k)
    7. HOUS9 ($80-200k)
    8. HOUSH ($200+k)
F. Enterprises
G. External Trading Partners
    1. ROUS Rest of United States
    2. ROW Rest of the World

These data enable us to trace the effects of responses to climate change and other policies at unprecedented levels of detail, tracing linkages across the economy and clearly indicating the indirect benefits and tradeoffs that might result from comprehensive policies pollution taxes or trading systems. As we shall see in the results section, the effects of climate policy can be quite complex. In particular, cumulative indirect effects often outweigh direct consequences, and affected groups are often far from the policy target group. For these reasons, it is essential for policy makers to anticipate linkage effects like those revealed in a general equilibrium model and dataset like the ones used here.

It should be noted that the SAM used with BEAR departs in a few substantive respects from the original 2003 California SAM. The two main differences have to do with the structure of production, as reflected in the input-output accounts, and with consumption good aggregation. To specify production technology in the BEAR model, we rely on both activity and commodity accounting, while the original SAM has consolidated activity accounts. We chose to maintain separate activity and commodity accounts to maintain transparency in the technology of emissions and patterns of tax incidence. The difference is non-trivial and considerable additional effort was needed to reconcile use and make tables separately. This also facilitated

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the second SAM extension, however, where we maintained final demand at the full 119 commodity level of aggregation, rather than adopting six aggregate commodities like the original SAM.

1.14.1 Emissions Data

Emissions data at a country and detailed level have rarely been collated. An extensive data set exists for the United States which includes thirteen types of emissions (see Table 1.14.1).[12] The emission data for the United States has been collated for a set of over 400 industrial sectors. In most of the primary pollution databases, measured emissions are directly associated with the volume of output. This has several consequences. First, from a behavioral perspective, the only way to reduce emissions, with a given technology, is to reduce output. This obviously biases results by exaggerating the abatement-growth tradeoff and sends a misleading and unwelcome message to policy makers.

More intrinsically, output based pollution modeling fails to capture the observed pattern of abatement behavior. Generally, firms respond to abatement incentives and penalties in much more complex and sophisticated ways by varying internal conditions of production. These responses include varying the sources, quality, and composition of inputs, choice of technology, etc. The third shortcoming of the output approach is that it give us no guidance about other important pollution sources outside the production process, especially pollution in use of final goods. The most important example of this category is household consumption.

1.15 Renewable Energy Cost Estimates

To impute costs to the renewable technologies being considered in our RPS scenarios, we combined data from multiple sources. The relevant information is summarized in the following

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[12] See Martin et. al. (1991).

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Table 1.15.1: Data and Assumptions for Renewable Cost

Technology	Capacity		Unit Costs				
	kW	Capital Cost ($/kW)	O&M ($/kW-year)	Fuel Cost	Capacity Factor	Capacity Discount	Incentive Percent
Central PV	100,000	$4,823	$10		25%	10%	46%
Commercial PV	75	$5,649	$11		25%	10%	46%
Residential PV	4	$7,200	$35		25%	0%	28%
Central CSP	100,000	$3,744	$55		40%	10%	46%
Central Wind	100,000	$1,434	$29		30%	50%	
Central Wind Offshore	100,000	$2,872	$87		30%	28%	
NGCC 2009	500,000	$706	$11	$4.50	70%		
NGCC 2020 DOE	500,000	$706	$11	$9.00	70%		
NGCC 2020 IEA	500,000	$706	$11	$14.50	70%		
Finance							
Discount Rate	4%						
Comparable Lifetime	25						
Capital Recovery Factor	0.064						

Sources: Wiser et al (2009), RETI (2009abc), CPUC (2009), Milligan and Porter (2005).

Levelized costs provide a means for comparing technologies with different design lifetimes and cost characteristics. For electricity generating technologies, there are generally four costs that are included in levelized cost calculations:

1. Capital costs, which are generally financed
2. Fixed annual costs
3. Operations and maintenance (O&M) costs
4. Fuel costs, if any

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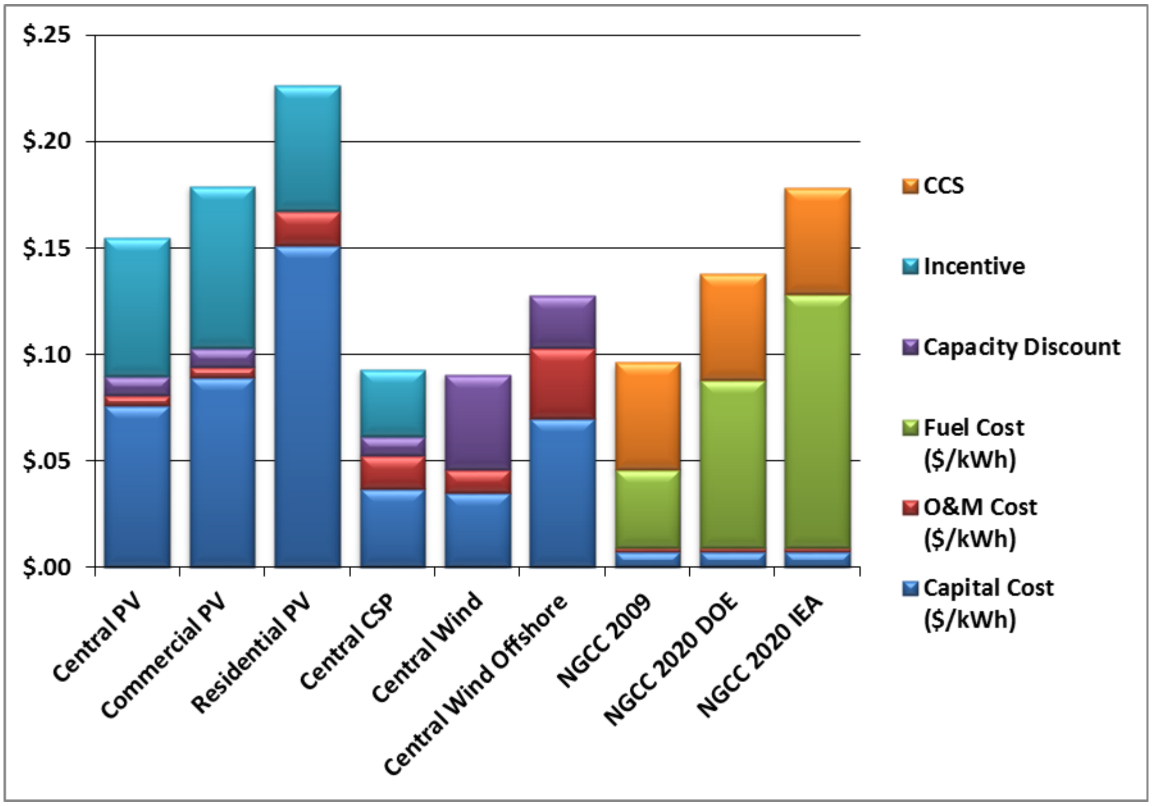
Cost	Units	Description
Capital costs	$/kW	Capital costs are often expressed in unit (per kW) terms. For instance, a 100 MW wind farm with a total capital cost of $300 million has a unit capital cost of $3,000/kW (1 MW = 1,000 kW).
Fixed annual costs	$/kW-yr	Fixed annual costs are expressed in terms of $/kW-yr, reflecting the fact that these costs are paid annually irrespective of output. Insurance and licensing, for instance, are fixed annual costs.
O&M costs	$/kWh	O&M costs are typical variable costs, and are expressed in terms of output ($ per kWh generated).
Fuel costs	$/kWh	Fuel costs also depend on output, and are expressed in kWh terms.

Figure 1.15.1: Renewable and Conventional Energy Cost Estimates



Source: Roland-Holst, David "Energy Prices and California's Economic Security," Next10.org, October, 2009.See the Annex below for estimation details.

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The most common approach to converting these costs into equivalent units is to annualize capital costs, and convert both capital and fixed costs to variable units by normalizing them by total operating hours.

Capital costs (CC) are annualized using a capital recovery factor (CRF)

$$CRF = \frac{r}{(1 - (1 + r)^{-t})}$$

where r and t can either reflect financing terms or, more frequently, a discount rate and a design lifetime.

Annualized capital costs (ACC) are thus

$$ACC = CC \times CRF$$

Annualized capital costs and fixed costs, now both in units of $/kW-yr, can be converted into variable costs by normalizing both by the number of annual hours that a given technology operates. Operating hours for different technologies are typically calculated using a rule of thumb capacity factor, defined as

$$CF = \frac{Annual\ Operating\ Hours}{Total\ Hours\ per\ Year}$$

Baseload coal- and natural gas-fired power plants, for instance, operate most of the year and have high capacity factors (~0.8), whereas intermittent resources like solar and wind are only available for a limited number of hours per year and have lower capacity factors (~0.2-0.4).

Total levelized costs (LVC, in $/kWh) can then be calculated as

$$LVC = \frac{ACC + FXC}{(CF \times 8760)} + OMC + FLC$$

where FXC is an annual fixed cost, OMC is an O&M cost, and FLC is a fuel cost.

Fuel costs can be calculated with the following formula:

$$\frac{\left(\frac{1}{\text{Efficiency}} \times 3.6\right)}{\text{Heating Value}_{\text{Fuel}}} \times \text{Price}_{\text{Fuel}}$$

where the efficiency is the thermal efficiency of the generating facility, 3.6 is a conversion factor between kWh and MJ, heating value is the higher heating value (energy content) of the fuel, and price is the price of the fuel in physical (mass or volume) units.

The resulting estimates are depicted in Figure 1.15.1, including existing incentives for PV adoption and a premium on fossil fuel electric power generation for carbon capture and storage.

BACKGROUND ASSESSMENT OF INDIVIDUAL INDUSTRIES

Climate change will have serious impacts on the state of California and is now widely recognized as an important risk to the economic activities and living standards of present and future generations. In response to this, the state has extended its long commitment to sustainable economic growth by implementing a series of initiatives for energy efficiency and GHG emissions reduction. In the latter category, Assembly Bill 32 represents landmark legislation to address climate change risks and move the California economy to a path of greater energy efficiency, productivity, and reduced environmental risk.

The central provision of AB32 is a set of targets for greenhouse gas (GHG) mitigation, to be achieved at least in part by a market oriented mechanism like a cap-and-trade scheme. While cap and trade is widely acknowledged for its potential to enlist market forces and private agency for efficiency improvement, the empirical evidence on detailed economic impacts of these policies remains weak. In this report, we evaluate the implications of policies like the proposed CO2 cap and trade system using a dynamic simulation model of the state economy.

The research reported here extended macroeconomic analysis developed to inform the legislative dialogue on AB32 during the summer of 2006 (Roland-Holst:2006b). While the macro results indicated that California’s growth and environmental objectives can be reconciled, they did not provide much detail on the structural adjustments that would attend this process. Perhaps for this reason, some observers (e.g. Stavins et al: 2007) mistakenly interpreted this work as promoting no cost solutions. In fact, any substantial climate action in California and any other modern economy will entail costs, but these can be substantially or completely outweighed at the aggregate level by offsetting benefits. Because detailed costs and benefits may accrue to different stakeholders, responsible climate action assessment requires consideration of both the magnitudes and composition of positive and negative adjustment effects. The primary objective of this report is to strengthen the basis of evidence in this area, and much more research could be productively undertaken to elucidate effects of complex policy alternative in greater detail. As part of this effort to better understand the economic adjustments that might ensue from cap and trade approaches to GHG regulation, a comprehensive review was conducted of publically available information on technology and cost structures in the state's first and second-tier GHG emitting industries. These information resources are summarized in four sections of this report, corresponding to Electric Power, Cement, Petroleum Refining, and Chemicals. While may insights have been gained in this process, the information in public hands remains too fragmentary to reliably predict detailed incidence patterns in these sectors.

Despite these limitations, this report attempts to improve general understanding of the salient forces at work within prominent individual industries. In doing so, it is possible to reach a variety of important conclusions, if not to identify individual enterprise winners and losers or plant-specific quantitative adjustments. Such detail would of course be of interest to enterprises, both those directly affected and those in competitive or contractual relationships with affected firms, but it is outside the scope of this analysis.

Several important messages for policy makers and stakeholders emerge from this review and analysis. For example, policies that restrict GHG emissions, while socially desirable, can lead to unintended adverse effects if they are defined too narrowly. When they impose new costs on industries, they also risk transferring those costs to society through the price system. More complete policies will recognize the combined potential of economic competition and investment in efficient technology to mitigate new cost/price pressures that arise in targeted industries.

Industries with high levels of competition will experience efficiency gains more spontaneously, as new entrants and incumbents seeking new market share invest in competitive innovation voluntarily. In other contexts, investment incentives can be provided, perhaps from resources generated by pollution licenses. In either case, explicit recognition and facilitation of the essential role played by innovation can hel secure win-win outcomes for both industry and society.

At a more detailed level, we draw conclusions about the adjustment process in several industries. For example, in the face of significant potential cost increases, the electric power distribution sector is likely to make important compositional adjustments in its generation portfolio over the next decade. Because the working life of these capital goods spans several decades, these decisions will establish new baselines for emission intensity and accelerate the need for future efficiency improvements.

In the cement sector, we infer that conformity to new GHG standards, even under relatively efficient cap and trade regimes, will confer nontrivial costs on this sector, and these will either be passed on to consumer, reinforce innovation incentives, or some combination of the two. Another unresolved issue in this sector concerns the potential of blended cement to offset this sector's carbon liability. The industry's largest individual customer, a public agency, is undecided about whether or not blended cement will meet its needs. This deadlock poses an important obstacle to the industry's strategy for meeting the state's own environmental objectives, and it also denies the cement market and essential precedent of adoption. Finally, there has been considerable discussion about the long term viability of within-state cement operations. It should be noted, however, that in no scenario we consider do Climate Action costs approach the kind of pressures the sector has repeatedly experienced from its energy fuel inputs. For this reason, it is difficult to imagine California's cement industry experiencing any relocation adjustments.

Oil refining is an exceptionally challenging industry for analysis because of the diversity of its product mix and pervasive linkages across the economy. Because it is the primary channel for GHG production by all forms of transportation and a significant component of other manufacturing activities, its response to GHG policies will have a very significant indirect component. Indeed, indirect mitigation of refinery emissions from attenuation of fuel demand trends can account for up to half this sector's GHG mitigation. This being said there are still significant opportunities for process innovation to achieve higher efficiency levels in this sector, although restrictions on new capacity development may retard this process.

The chemicals sector is another example of a very diverse sector with strong indirect linkages. As a California manufacturing sector, it is second in GHG emissions only to Petroleum refining. Despite this, the largest component of the industry, pharmaceuticals, bears indirect responsibility for most of its GHG emission through electricity and energy intensive input demands. Opportunities for process innovation are considerable across this sector, but it is clear that no single prescription for technological change or other structural transition will fit all cases in such a diverse environment. More than any industry considered in this study, chemicals demonstrates the value of market oriented policies that enlist private agency to find individual solutions that fulfill public objectives.

In this section, we discuss the initial conditions for prominent individual industries and appraise prospects for their adjustment to AB32, reviewing available data on industry structure and conduct and explaining how each sector was implemented in the model. The report closes with summary remarks and a discussion of how this framework will be extended to provide more extensive support for climate action policies.

Table 1.15.1 subdivides the 50 sectors in the current BEAR database into three groups, corresponding roughly to average GHG pollution intensity of output. As we discuss individual sector climate policy responses below, we will evaluate three extensions of the basic ARB1 policy case. Each of these Expanding beyond the AB32 scenario, we examine a progressively larger coverage of a cap on emissions designed to make up the remaining reduction in emissions. The three industries in Group 1 are frequently identified as the highest priority sectors for a GHG cap. Our results for Scenario 3 suggest, however, that these sectors almost certainly should not bear the burden of adjustment to the 2020 targets alone. Indeed, BEAR estimates of their baseline GHG emissions for 2020 are about 173MMT, while hitting the target would require about 90MMT in emission reductions, an implied annual reduction in sectoral intensity of over 3.5%.

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Table 1.15.1: Alternative Industry Emission Groups

1. **Group 1: First-tier Emitters**

A04DistElc	Electricity Suppliers
A17OilRef	Oil and Gas Refineries
A20Cement	Cement

2. **Group 2: Second-tier Emitters**

A01Agric	Agriculture
A12Constr	Construction of Transport Infrastructure
A15WoodPlp	Wood, Pulp, and Paper
A18Chemicl	Chemicals
A21Metal	Metal Manufacture and Fabrication
A22Aluminm	Aluminium Production

3. **Group3: Other Industry Emitters**

A02Cattle	Cattle Production
A03Dairy	Dairy Production
A04Forest	Forestry, Fishery, Mining, Quarrying
A05OilGas	Oil and Gas Extraction
A06OthPrim	Other Primary Activities
A07DistElec	Generation and Distribution of Electricity
A08DistGas	Natural Gas Distribution
A09DistOth	Water, Sewage, Steam
A10ConRes	Residential Construction
A11ConNRes	Non-Residential Construction
A13FoodPrc	Food Processing
A14TxtAprl	Textiles and Apparel
A16PapPrnt	Printing and Publishing
A19Pharma	Pharmaceuticals
A23Machnry	General Machinery
A24AirCon	Air Conditioner, Refrigerator, Manufacturing
A25SemiCon	Semiconductors
A26ElecApp	Electrical Appliances
A27Autos	Automobiles and Light Trucks
A28OthVeh	Other Vehicle Manufacturing
A29AeroMfg	Aeroplane and Aerospace Manufacturing
A30OthInd	Other Industry

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Table 1.15.2: Policy Scenarios for Climate Action

1. **Baseline (no emission reduction target) [1]**
2. **ARB1 policies with emission cap applied to**
    a. **Industries in Group 1 [2]**
    b. **Industries in Groups 1 and 2 [3]**
    c. **Industries in Groups 1, 2 and 3 [4]**

When the scope of industry coverage is expanded to include the nine industries in Group 2, Scenario 3, the results are much more encouraging. In this scenario, the nine sector group could meet the governor's 2020 targets with less than 3% annual improvements in average emission intensity.[13] While this seems a feasible aggregate objective, however, it is important to recognize that the adjustment burden will fall differently on different sectors, depending on their initial intensity and share of the mitigation they must achieve. One of the advantages of detailed simulation models like BEAR is that they capture these important compositional effects, and in Table 1.14.3Table 1.14.2 we see how increasing scope diffuses the burden of adjustment.

In this scenario, the nine sectors responsible for meeting the target will have to reduce emission intensity by up to 3.65% per annum, sustaining this over a nine year period. This level, too, will be difficult to sustain. Even when scope is extended to all industries, Scenario 4, nine year average annual efficiency gains of over 2.9% would be needed.

The main alternative to this would be extending regulation to services and mobile sources or to orchestrate the present scenario with other GHG policies, yet the all-inclusive Scenario 4

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[13] Note in Table 4.3 that several sectors have much higher annual intensity reductions, some over 4.5%, because of legacy effects from being targeted by CAT policies.

indicates this would still require more than 2% annual mitigation and the administrative feasibility of such a program is very doubtful.

The results in Scenario 4 results are broadly consistent with what is assumed in some other policy analyses. For example, the President's climate change policy for voluntary GHG emission intensity reductions stipulates 2% mitigation per year for ten years (Abraham, 2004), and this goal is approximately in line with historical national trends. California itself has experienced approximately a 2% decline in GHG intensity from 1990-2000 (Climate Action Team, 2006). It must be recalled, however, that these scenarios include some mandatory (direct regulation) AB32 policies. The clear message is that California must take policy initiative to achieve these overall levels of abatement.

From Scenarios 2-4, we can draw a few salient inferences. Firstly, industry-oriented GHG mitigation needs to be relatively inclusive if the adjustment burden is to be manageable. Second, this category of policy needs to be coordinated with other substantial commitments to GHG efficiency (e.g. AB32 regulatory policies). In the case considered here, where an inclusive industry policy is combined with other GHG regulatory initiatives, we find that industry must still improve energy efficiency and GHG gas intensity substantially. Although the implied rates of improvement are probably feasible, they appear to be significantly outside the range of voluntary compliance.

1.16 Electricity

Our results indicate that the electric power sector can be a primary contributor to GHG reductions in the state, but for this sector policy choice and implementation will make a critical difference to the outcomes for all stakeholders. If a less inclusive (First-tier) cap is chosen, this sector will have to achieve emission reductions averaging over 4% per year over a decade. This is a very ambitious target, and can only be met with a combination of outlays for pollution permits in the short run and capacity shifting to more efficient sources in the long run. Both these activities will escalate costs, and we estimate that electricity prices could be nearly 20% higher by 2020 as a result. This kind of price escalation will increase costs for electricity users, directly in consumption, and indirectly in the form of expenses for induced technology adoption.

Table 1.16.1: Structural Adjustment in the Electric Power Sector

(percent change from Baseline in 2020)

	Scenario 2	Scenario 3	Scenario 4
	Group 1	Group 12	Group 123
Emissions	-51%	-39%	-30%
Price	20%	9%	5%
Output	-8%	-4%	-2%

As the simulation results in

Table 1.16.1 indicate, structural adjustment in the sector could be quite dramatic. If only the first-tier emitters were targeted for a cap and trade system, by 2020 Electric Power will have to reduce emissions by half. The ensuing adjustments would increase retail price pressure by up to 20%[14], while state industry output falls by 8%.

More inclusive caps will defray this adjustment burden to other sectors, prices, and commodity classes, but without investment incentives the overall "new" cost of the cap and trade scheme will impose efficiency costs on the state economy. The key to averting this is promotion of innovation and technology adoption, as can be clearly seen in the last two scenarios. When cap and trade policies provide rebates for investment and adoption of more efficient technology, the result is neutralization cost/price inflation and sustained growth.

Having said this, it is important to note that structural change will have more detailed costs, even when industrywide and statewide nets benefits are realized. To see this, note the dispersion of efficiency levels in the states, existing generation capacity, as depicted in Figure 1.16.1 for the largest generation sites, together representing half of California's capacity. Even within the natural gas generation cohort, observed efficiency levels can vary by a factor of two. Clearly, the Load Serving Entities (LSEs) will have strong incentives to shift their portfolios

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[14] It should be borne in mind that this price adjustment assumes market clearing prices are accepted by regulatory authorities. Administered prices at other levels would propagate distortions elsewhere.

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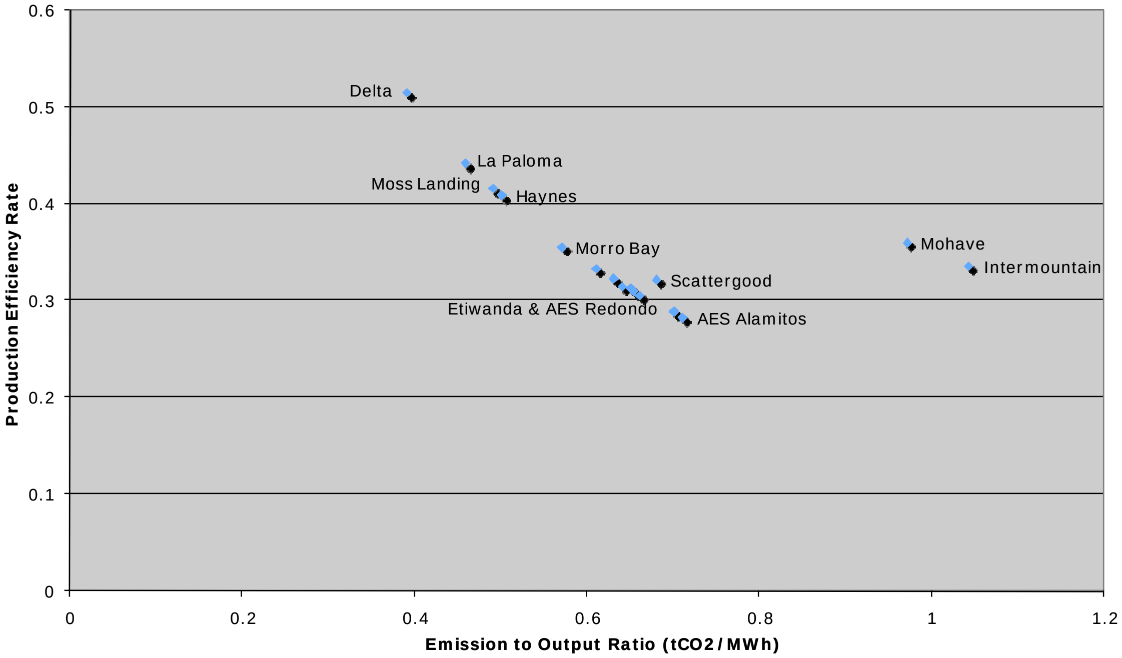
across these sources (from right to left) as they come under increasing GHG regulation. This kind of shifting will drive up capacity use and costs from the more efficient sources, but in any case is likely to be a first alternative to new investments in the short and medium term. The exact composition of this shift would be very useful to anticipate, both for the sake of private stakeholders and public agencies who might be able to mitigate the ensuing adjustment costs. It cannot, unfortunately, be estimated from publicly available information.

Figure 1.16.1: Emission Rates and Production Efficiency



Accounting for 16% of California registered CO2 emissions, the electric power sector will play an essential role in meeting the state's GHG targets. To better understand this essential strategic sector, we consider it in two parts. First, we discuss distributors of electricity, an industry dominated by three Load Serving Entities (LSE's) and a large and diverse group of smaller electricity distributors. Demand by the LSE's ultimately determines patterns of emissions from electric power generation, so they are likely targets of any policies to mitigate emissions from power generation, and their behavior and contracting activities need to be understood. After an overview of the distributors, we move back up the electricity supply chain

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to the generating technologies themselves. Here plant characteristics will be the primary determinants of structural adjustment, with more efficient plants in a better position to adapt to regulatory change in a cost effective manner.

1.16.1 Modelling the Behavior of Load Serving Entities

A standard economic simulation framework models industrial and service activities with one representative firm per sector, assuming production arises from neoclassical assumptions of profit maximization and perfect competition. For a variety of reasons, this paradigm is not an accurate or even reliably approximate reflection of the structure and conduct of the electricity distribution sector. When elaborating a standard economic model for this purpose, three salient characteristics need to be taken into account:

1. Larger LSE's are not firms are representable by a single homogeneous production function, but distinct entities with delineated markets who draw their supply from a portfolio of generation technologies.

2. Output prices in this sector are rigid.

3. Because of the economic costs of supply uncertainty, this sector maintains substantial excess capacity.

Schematically, the market structure of this sector is described in Figure 1.16.2 below. There are three leading LSEs, Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. The fourth LSE represents an aggregate of all other electricity distributors. Each of these hires its own factors of production (labor capital) and draws upon portfolio of in-state and out-of-state generation technologies, extracting electricity supply from them by direct ownership or contracts for delivery.

In response to the special characteristics listed above, the BEAR model adds special structural features for this sector. These include the following characteristics:

Individual firm specification for each of the four LSE's in Figure 1.16.2.

1. Fixed prices in a demand-driven market.

2. In the short run, LSE's choose the level of capacity utilization.

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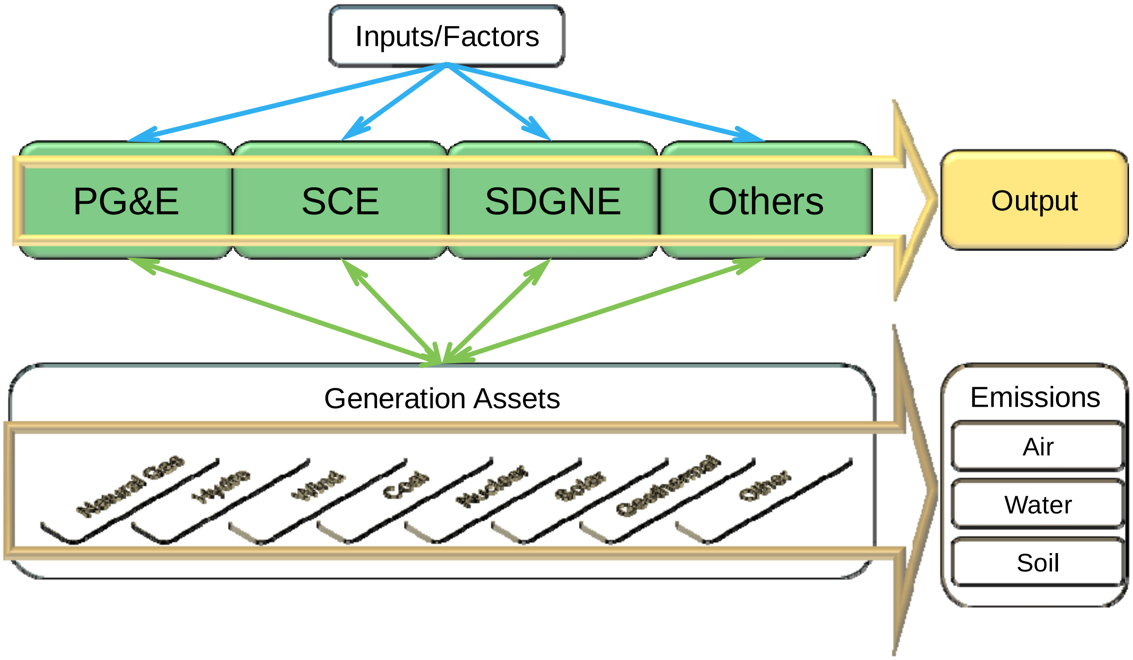
3. In the long run, LSE’s choose capacity via investment and contracting.

The California electricity generation system is one of the largest contributors to greenhouse gas emissions in the state. In looking at the top tier producers (totaling 41% of California generation capacity[15]), it is apparent that California suppliers may be better able to adapt to forthcoming carbon restrictions. In today’s California electricity industry, portfolio decisions by the LSE’s have led to capacity that is significantly less carbon-intensive than national averages. As Figure 1.16.3 indicates, California electric power relies significantly less on coal, more on hydro and natural gas than does the nation as a whole (including California). Renewable technologies have also emerged more strongly in the state.

Figure 1.16.2: Schematic Structure of the Electricity Distribution Sector



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[15] http://www.energy.ca.gov/

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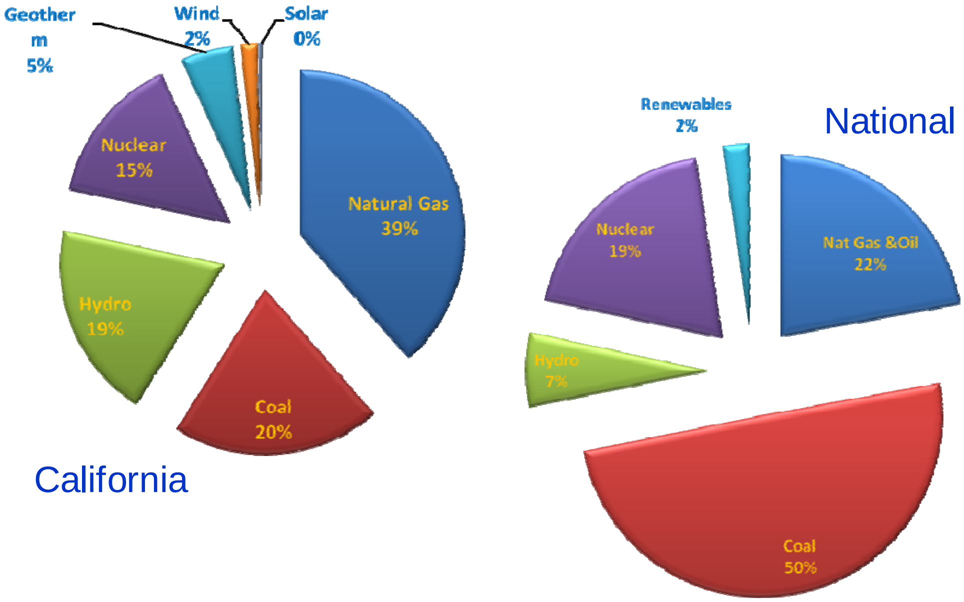
Figure 1.16.3: Technology Portfolios for Electric Power Generation



1.16.2 *Power Generation at the Plant Level*

This is not to say, however, that the electricity sector will not face significant obstacles. Many of California's critical electrical plants rely on older technologies that do not maximize fuel efficiency. Inefficient fuel utilization presents the source of greatest risk for survival of a plant in a cap-and-trade regulatory environment. This is because the average fuel cost of production ($/MWh) dominates marginal cost of production for each and every one of these plants. Their ability to produce and sell their output competitively, either to LSE's though contracts or for them if they are wholly-owned capital assets, depends critically on this. In a market facing rising fuel cost trends, inefficient fuel utilization magnifies average fuel cost pass through to marginal costs, intensifying diminishing profit margins (see Figure 1.16.4).

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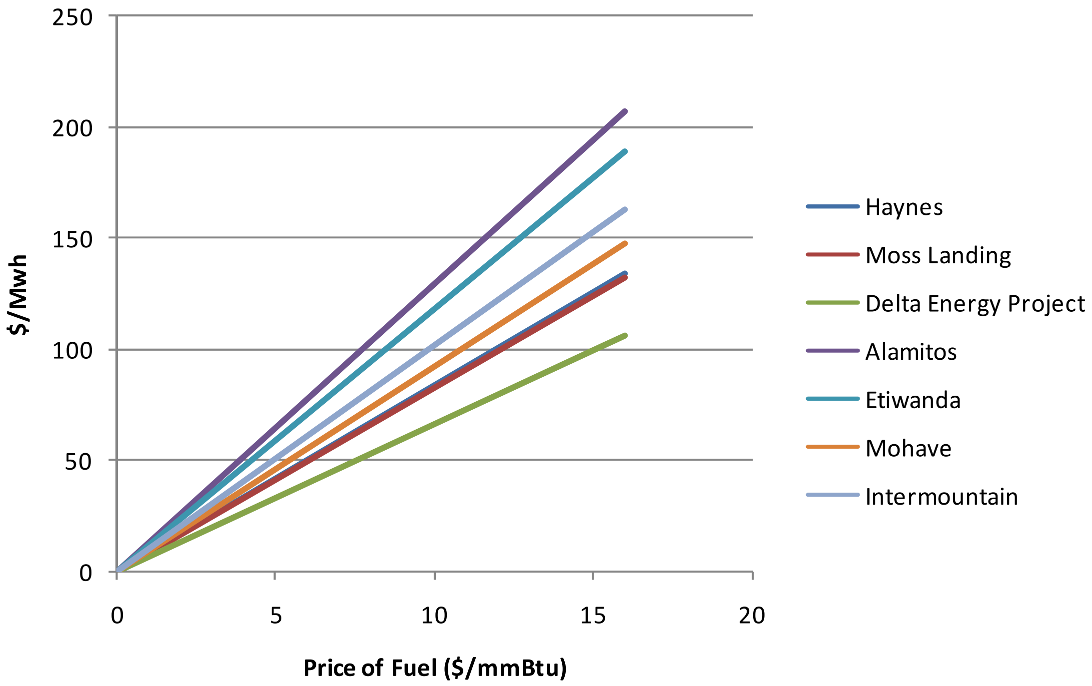
Figure 1.16.4: Estimated Marginal Cost with Respect to Fuel Prices



This is a subject we will discuss more deeply upon closer scrutiny of individual plants. We begin, however, with a general overview of the state’s electric power generation sector. There are over 900 electrical generating facilities in California. About 20 large plants produce almost 50% of total output (Figure 1.16.5), and these larger plants will be the focus of the present study.

In particular, we reviewed 18 natural gas plants which provide 66% of California’s electricity (including imports) and two coal plants, Mohave and Intermountain, located in Nevada and Utah respectively but are owned by Californian companies. Mohave and Intermountain both have historically been large contributors to California’s electric power capacity. Mohave, however, closed down at the end of 2005 due to a court order (to clean up emissions or cease operation) issued in 1999. Intermountain, on the other hand, is still open but having difficulty finding utilities to buy its output. On December 13, 2006, Truckee Donner Public Utility District near Lake Tahoe voted to reject power from Intermountain Coal Plant. Generally speaking, despite low costs, coal plants seem to be on the decline when it comes to California consumer choice. The rest of the California plants are Natural Gas powered and quite diverse in their

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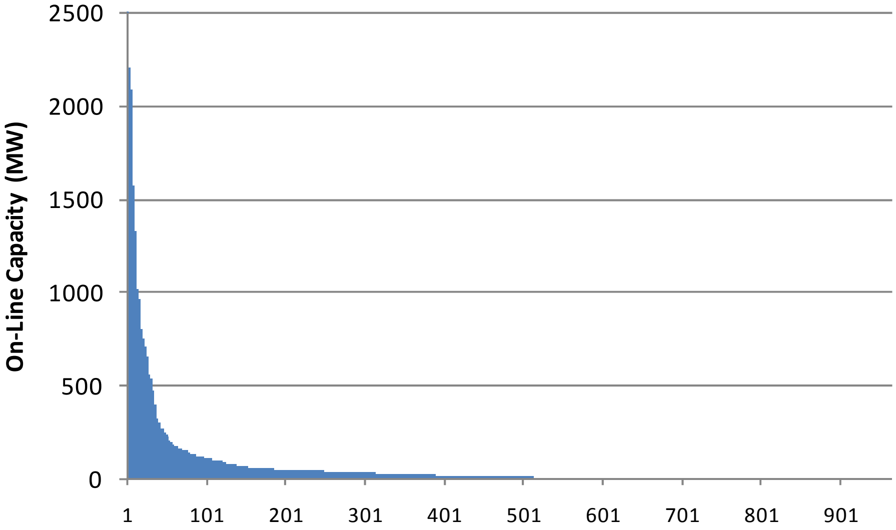
modernization level and preparedness for a carbon cap-and-trade system. A complete list of plants surveyed in this report is given in Table 1.16.2.

Figure 1.16.5: Size Distribution of Electric Power Facilities, California



The competitiveness of plants under the new system will hinge principally upon two factors, how well they minimize carbon output (measurable by the emission to output ratio tCO2/MWh) and maximize fuel efficiency rates. For the sake of discussion, we derive a competitiveness index (Fuel Efficiency ratio divided by the emission to output ratio) to rank Natural Gas fired plants in terms of adaptability to more stringent GHG emissions regulation. The same index can be used to rank coal-fired plants, however, ranks across plant time should not be compared due to differing price/mmBtu.

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Table 1.16.2: Top Tier California Electric Power Plants

	Fuel Type	MW Capacity	Share of CA	CO2 Emissions	Share of Sector
Moss Landing	Nat. Gas	2545	4.06	2,376,736	7.51
AES Alamitos	Nat. Gas	2087	3.33	974,950	3.08
Intermountain	Coal	1640	2.62	15,182,583	N/A
Mohave	Coal	1636	2.61	10,770,045	N/A
Haynes	Nat. Gas	1570	2.51	1,875,177	5.92
Ormond Beach	Nat. Gas	1492	2.38	341,390	1.08
Pittsburg	Nat. Gas	1332	2.13	449,662	1.42
Redondo Beach	Nat. Gas	1317	2.10	300,901	0.95
Morro Bay	Nat. Gas	1021	1.63	189,495	0.60
La Paloma	Nat. Gas	968	1.55	2,164,683	6.84
Huntington Beach	Distillate Oil	880	1.41	1,000,720	3.16
Delta Energy Cntr.	Nat. Gas	861	1.38	2,257,632	7.13
Scattergood	Nat. Gas	803	1.28	773,854	2.44
Etiwanda	Disillate Oil	770	1.23	546,027	1.72
High Desert Power	Nat. Gas	750	1.20	1,572,707	4.97
Coolwater	Nat. Gas	726	1.16	247,314	0.78

Table 1.16.3 presents the basic competitiveness estimates. A clear monotone trend suggests the near perfect correlation between fuel and emission efficiency, as well as the veracity of the underlying data. From the competitiveness estimates in Table 1.16.3 we see that these indexes can differ by a factor of three or four. This implies that significant adjustment patterns can be expected across these suppliers, either in terms of sales, technology renewal, or both. Of course there are many constituents to individual plant balance sheets, and other determinants of the their competitiveness. These include market access and conveyance costs, legacy capital and resource costs, and a variety of non-fuel variable costs of operating and maintaining plants.

Unfortunately, information on these characteristics at the plant level is very difficult to obtain. However, industry averages of this information indicate that the ranges of non-fuel O&M costs we have estimated independently to bounded at about $2/MWh. As will become apparent below, this is negligible when compared to average fuel costs of production ($/MWh).

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Table 1.16.3: Emissions, Efficiency, and Competitiveness by Plant

Plant	Tons CO2/MWH	Efficiency	Competitiveness Index
Delta Energy	.39	.52	1.32
La Poloma	.46	.44	.97
Moss Landing	.49	.42	.85
Haynes	.50	.41	.82
Morro Bay	.57	.36	.62
Coolwater	.61	.33	.55
Ormond Beach	.63	.32	.51
AES Huntington	.64	.31	.49
Pittsburg	.65	.31	.48
High Desert	.65	.31	.47
Scattergood	.68	.32	.47
Cabrillo/Encina Power	.66	.31	.46
AES Redondo	.70	.29	.41
Etiwanda	.70	.29	.41
AES Alamitos	.71	.28	.40
Mohave*	.97	.36	.37
Intermountain*	1.04	.34	.32

Source:

*Coal used as primary fuel.

We now review a subset of the leading plants to give a general indication of the primary drivers of efficiency. Their basic cost data are summarized in Table 1.16.4 below.

Table 1.16.4: Estimated Plant Cost Data

Name	Facility	Unit	Year in Service	Avg Fuel Price cts/MMBtu	Avg Fuel Price $/MWh	Fixed O&M $/kW	Non-fuel Var O&M $/MWh	Total O&M $M	Total O&M $/MWh	Capital $/kW
AES Alamitos	315	1	1956	572.16	67.67	19.8	0.98	206.862	79.72	155.66
AES Alamitos	315	2	1957	572.16	67.67	19.8	0.98	206.862	79.72	155.66
AES Alamitos	315	3	1961	572.16	67.67	19.8	0.98	209.971	79.72	155.66
AES Alamitos	315	4	1962	572.16	67.67	19.8	0.98	210.030	79.72	155.66
AES Alamitos	315	5	1966	572.16	67.67	19.8	0.98	213.000	79.72	155.66
AES Alamitos	315	6	1966	572.16	67.67	19.8	0.98	213.000	79.72	155.66
Haynes Station	400	1	1962	641.93	69.89	13.7	2.3	151.303	81.59	214.05
Haynes Station	400	10	2005	510	36.72	15	2	8.625	40.43	214.05
Haynes Station	400	2	1963	641.93	69.89	13.7	2.3	151.303	81.59	214.05
Haynes Station	400	5	1966	641.93	69.89	13.7	2.3	152.933	81.59	214.05
Haynes Station	400	6	1967	641.93	69.89	13.7	2.3	152.933	81.59	214.05
Haynes Station	400	9	2005	510	36.72	15	2	8.625	40.43	214.05
Pittsburg Power Plant (CA)	271	5	1960	644.85	62.25	11.98	1.08	118.565	72.44	227.55
Pittsburg Power Plant (CA)	271	6	1961	646.73	62.25	11.98	1.08	118.624	72.44	227.55
Pittsburg Power Plant (CA)	271	7	1972	571.04	62.25	11.98	1.08	122.998	72.44	227.55
Ormond Beach Station	350	1	1971	574.84	59.99	18.14	0.98	150.526	73.24	
Ormond Beach Station	350	2	1973	574.84	59.99	18.14	0.98	151.143	73.24	
AES Redondo Beach	356	5	1954	573.27	62.54	19.8	0.98	85.673	81.49	184.43
AES Redondo Beach	356	6	1957	573.27	62.54	19.8	0.98	85.596	81.49	184.43
AES Redondo Beach	356	7	1967	573.27	62.54	19.8	0.98	91.896	81.49	184.43
AES Redondo Beach	356	8	1967	573.27	62.54	19.8	0.98	91.771	81.49	184.43
Morro Bay Power Plant	259	3	1962	575.04	56.1	16.06	1.1	24.840	79.5	236.02
Morro Bay Power Plant	259	4	1963	575.04	56.1	16.06	1.1	24.824	79.5	236.02
Etiwanda Station	331	3	1963	575.05	68.11	14.03	0.98	19.808	97.27	150.14
Etiwanda Station	331	4	1963	575.05	68.11	14.03	0.98	19.808	97.27	150.14
AES Huntington Beach	335	1	1961	570.17	62.25	19.75	0.98	98.121	75.28	161.23
AES Huntington Beach	335	2	1958	570.17	62.25	19.75	0.98	98.152	75.28	161.23
AES Huntington Beach	335	3A	1958	570.17	62.25	19.75	0.98	98.152	75.28	161.23
AES Huntington Beach	335	4A	1961	570.17	62.25	19.75	0.98	98.350	75.28	161.23
Delta Energy Center, LLC	55333	1	2002	569.81	41.65	11.79	0.79	247.118	44.61	
Delta Energy Center, LLC	55333	2	2002	569.81	41.65	11.79	0.79	247.118	44.61	
Delta Energy Center, LLC	55333	3	2002	569.81	41.65	11.79	0.79	247.118	44.61	
Scattergood Station	404	1	1958	630.4	69.52	27.42	3.05	121.399	85.02	286.16
Scattergood Station	404	2	1959	630.4	69.52	27.42	3.05	121.399	85.02	286.16
Scattergood Station	404	3	1974	630.4	69.52	27.42	3.05	128.693	85.02	286.16
Coolwater Station	329	1	1961	575.06	69.92	18.14	0.98	2.514	103.78	279.05
Coolwater Station	329	2	1962	575.06	69.92	18.14	0.98	2.804	103.78	279.05
Coolwater Station	329	31	1978	574.74	60.92	13.5	0.83	31.403	67.55	279.05
Coolwater Station	329	32	1978	574.74	60.92	13.5	0.83	31.403	67.55	279.05
Coolwater Station	329	41	1978	574.74	60.92	13.5	0.83	31.403	67.55	279.05
Coolwater Station	329	42	1978	574.74	60.92	13.5	0.83	31.403	67.55	279.05
Cabrillo | Encina Power	302	1	1954	571.36	63.03	18.07	1.06	198.838	70.57	329.91
Cabrillo | Encina Power	302	2	1956	571.36	63.03	18.07	1.06	198.874	70.57	329.91
Cabrillo | Encina Power	302	3	1958	571.36	63.03	18.07	1.06	198.929	70.57	329.91
Cabrillo | Encina Power	302	4	1973	571.36	63.03	18.07	1.06	200.645	70.57	329.91
Cabrillo | Encina Power	302	5	1978	571.36	63.03	18.07	1.06	200.916	70.57	329.91
Moss Landing	260	1A	2002	568.99	39.23	10.1	0.78	217.023	42.7	223.04
Moss Landing	260	2A	2002	568.99	39.23	10.1	0.78	217.023	42.7	223.04
Moss Landing	260	3A	2002	568.99	39.23	10.1	0.78	217.023	42.7	223.04
Moss Landing	260	4A	2002	568.99	39.23	10.1	0.78	217.023	42.7	223.04
Moss Landing	260	6-1	1967	572.92	49.08	17.76	1.09	71.433	60.35	223.04
Moss Landing	260	7-1	1968	572.92	49.08	17.76	1.09	71.450	60.35	223.04

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Moss Landing Power Plant

Industry Overview: The Moss Landing electrical plant is the largest in California and is located in the Monterey Bay on the Central Coast. It has a combined output capacity of 2500 MW, enabling it to deliver a little over 4% of California's in state electrical generating capacity and about 7.4% of electric power CO2 emission[16].

Production Statistics: Its primary fuel like the majority of major plants in California is natural gas. It consumes an average just under 4 million mmBtu per month. While the fuel consumption has stayed relatively constant during off peak months over the last few years, recent updates have led to an increase in the plants baseload output. Whereas previous to 2005, a typical off-peak monthly output would be 250,000 MWh, new improvements have led to consistent base load output of 480,000 MWh per month[17] (output graph in Fig 5.6).

Technology: This difference highlights changes in the technology used at Moss Landing. In October of 2000 the California Energy commission approved the construction of new natural gas powered combined cycle units to replace the old Units 1-5 which had been in use since the plants initial construction in the 1950's and had been shut down in 1995. These new units came online in 2002, however the full effectiveness of these units did not come become apparent until 2005 where a large increase in the fuel efficiency of the plant from 30% to nearly 48% can clearly be seen. Where units 1-4 are new, units 6 and 7 are supercritical boilers that are less fuel efficient averaging at 35% efficiency. These units however are only used during the summer months and for a few hours a day in order to meet peak energy demand. Therefore, their effect on CO2 emissions of the peaking units is not very substantial. See Moss Landing efficiency graph in Figure 1.16.6.

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[16] Figures for 2005 provided by the California Energy Commission.

[17] Averages from 2003-2005 from EPA.

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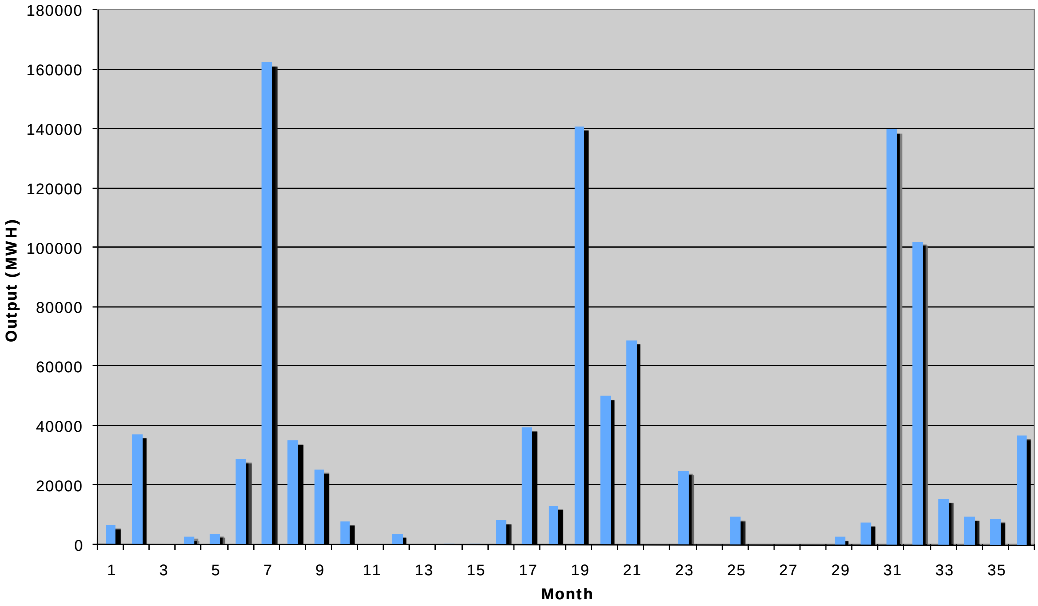
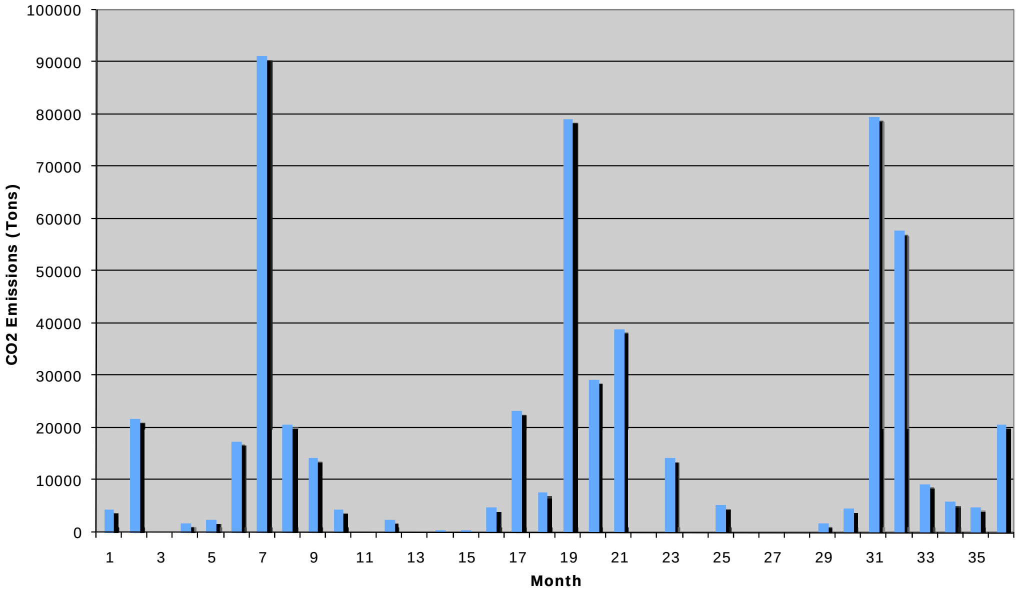
Figure 1.16.6: Morro Bay

Morro Bay Output '03-'05



Morro Bay CO2 Emissions '03-'05



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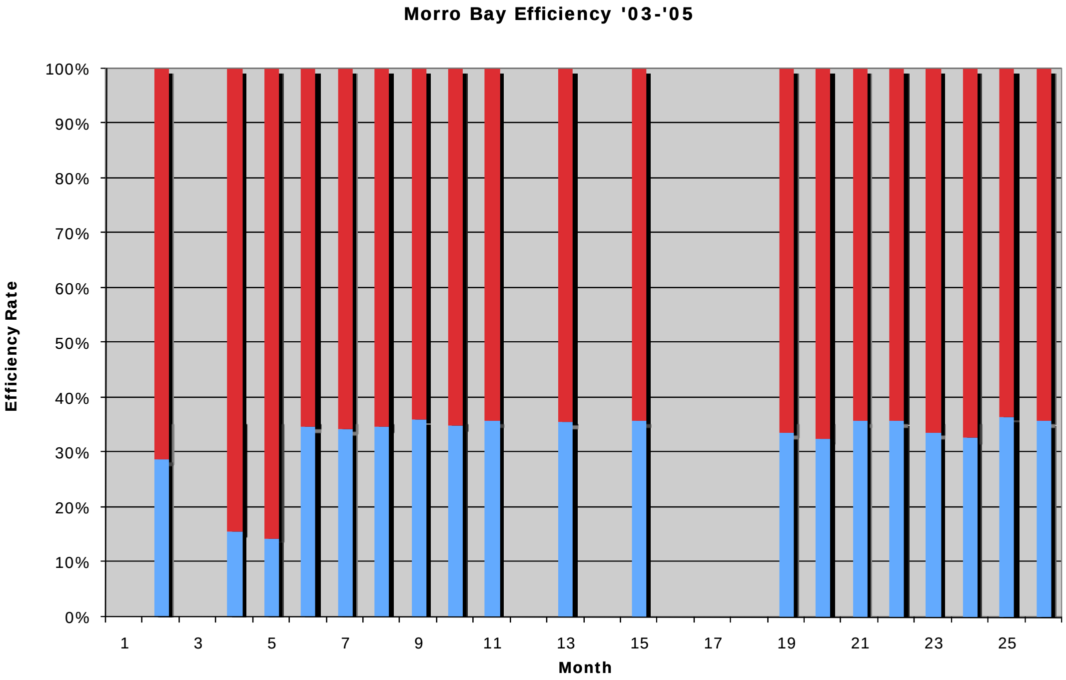

Emissions: Regarding CO2 emissions, Moss Landing emitted a total of 2,376,736 tons of CO2 in 2005[18]. That figure is a decrease of 16.5% of emissions from 2004 when Moss Landing emitted 2,846,628 tons. This is despite an 8.4% increase in the MWh output from 2004 to 2005 of Moss Landing. One may reasonably expect that the actual effects of the new, more efficient technology coming on-line to be even greater in 2006 because Moss Landing was only operating at the more efficient levels of production for eight months of 2005. See Moss Landing CO2 Emissions graph in Figure 1.16.6.

Costs and Competitiveness: With regard to cost, it is difficult to interpret the exact dollar values of average and marginal costs. However, we have been able to break down the cost structure of firms based upon the vintage and efficiency of their capital. This is because the largest slice of marginal cost is taken up by fuel costs. Thus if we take the average price for one mmBtu of natural gas for 2004 ($5.81/mmBtu[19]) and convert that amount of energy to MWh with 30% efficiency versus 48% efficiency, we get a good estimation of the money saved on fuel per MWh. The result is that a plant with 48% efficiency will have a marginal fuel cost of

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[18] www.epa.gov
[19] www.energy.ca.gov/naturalgas/monthly_update/2004-08_NATURAL_GAS_UPDATE.PDF

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$41/MWh while the less efficient plant will have a marginal fuel cost of $66/MWh. Thus, because of the upgrade, Moss Landing is now saving itself $25/MWh and reducing its marginal pollution (tCO2/MWh)

While fuel is the most consequential part of marginal cost, there are also variable operation and maintenance costs to consider. Like fuel cost per megawatt hour, these too vary based upon the vintage of the capital. Estimates however, show that these costs are initially quite low, averaging about $1/MWh to begin with and have a range of about $2/MWh.

Because of the upgrades this plant has undergone in the last few years. It ranks as number three in the competitiveness index indicated above. The following plant reviewed, Delta Energy Center, is ranked first in the competitiveness index and is a model of productivity maximization and externality minimization.

Delta Energy Center

Delta Energy Center Industry Overview: Delta Energy Center is a combined cycle natural gas plant (meaning it includes both gas and steam turbines) and upon construction was the largest power plant to come online in the state in 16 years[20]. It first came online in 2002 and has three units all located in Pittsburg with a generating capacity of 880 megawatts. The plant is big enough to serve every household in Contra Costa, Alameda and Solano counties and able to produce enough electricity to power about 660,000 homes or 1.3% of California Electric Generating capacity[21].

Production Statistics: As mentioned before Delta uses Natural Gas to generate electricity. Delta consumes 25,130,811 mmBtu a year and produces 5,740,290 MWh of electricity according to 2005 data. Of all the plants reviewed in this report Delta is the most efficient in terms of emission to output ratio and the most competitive (see competitiveness graph in Figure 1.16.3). Figure 1.16.7 shows the output of Delta for the years 2003-2005, emissions, and efficiency. There is a noticeable increase in output and efficiency in the year 2005 which is most likely due to the plant being in full operation by that time. One may reasonably expect

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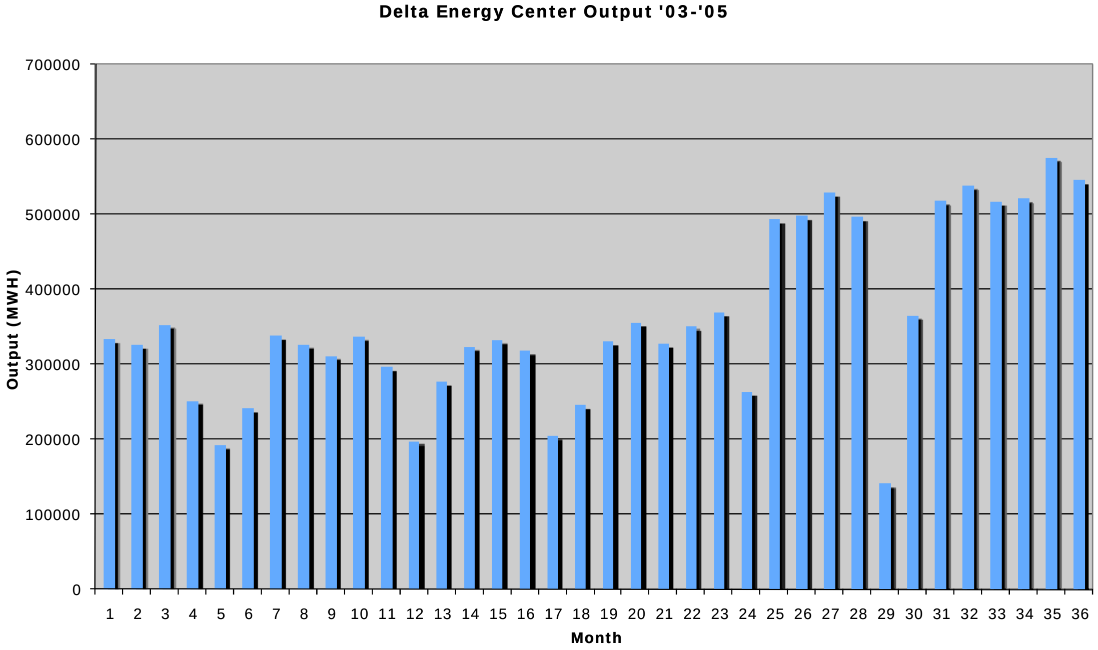
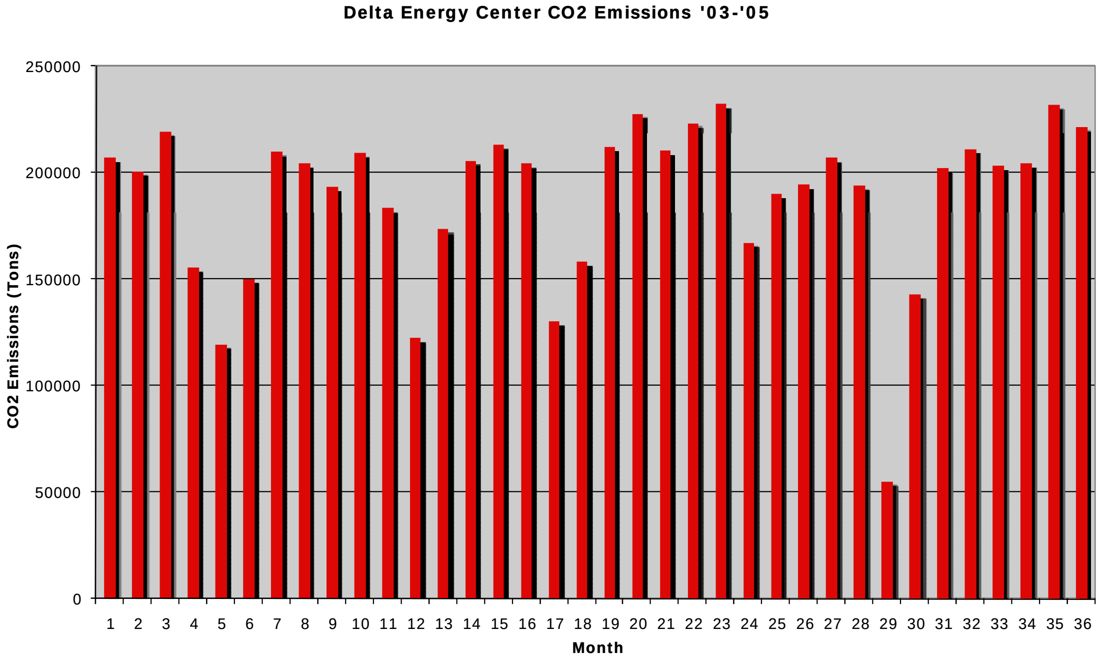
[20] The Chronicle Publishing Co. The San Francisco Chronicle June 18, 2002

[21] Ibid.

that the plant will continue operating at the 2005 levels of output in the foreseeable future given the relative currency of the technology.[22]

Figure 1.16.7: Delta Energy Center





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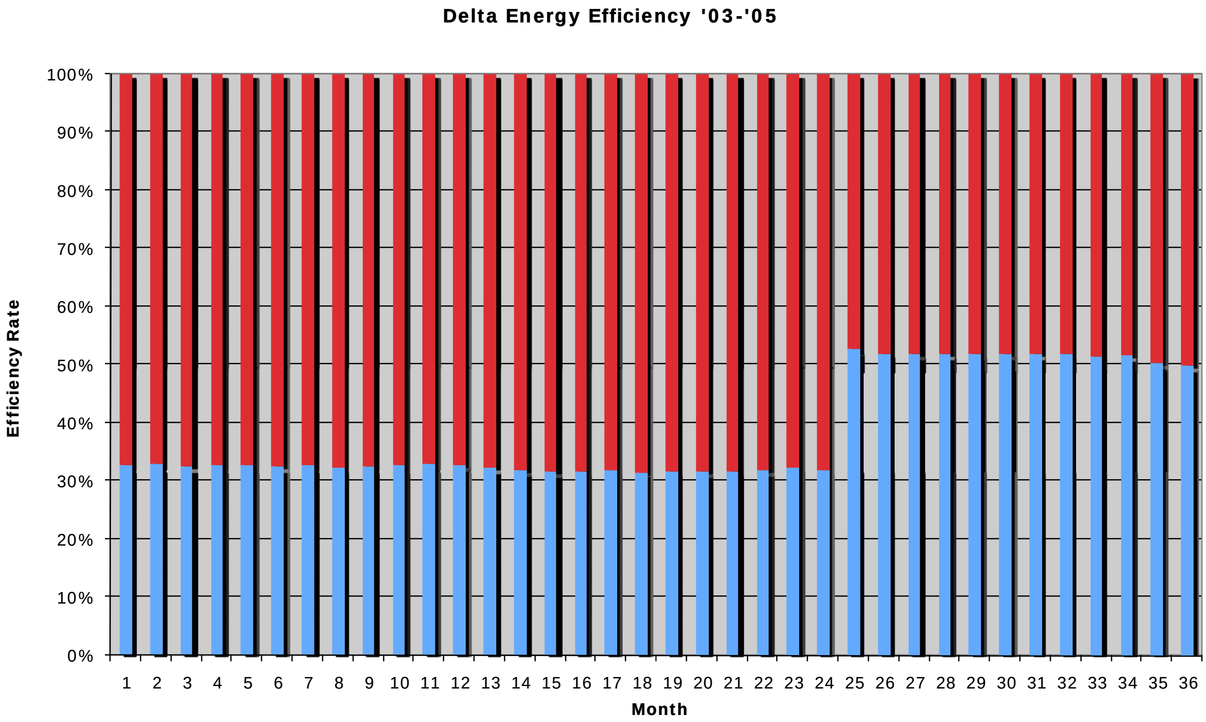
[22] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard



Technology: The Delta plant uses combined cycle cogeneration technology in all three of its units in order to produce electricity[23]. This technology has proved to be the most efficient in electricity production with a 50% fuel efficiency output for all of 2005. This is the highest efficiency rate for all major plants in California. See Efficiency graph in Figure 1.16.7.

CO2 Emissions: The Delta energy center emitted 2,257,631.8 tons of CO2 in 2005 or approximately 7.1% of CO2 emissions by CA electrical plants[24]. Note that the CO2 emissions showed in Figure 1.16.7 do not mirror MWh output, as with most plants; despite consistent increases in Delta's productivity and output, CO2 emissions appear to be uniform over the 2003-2005 time period.

Costs and Competitiveness: Regarding costs, Delta's fuel efficiency allows it to minimize fuel costs by needing less fuel to reach its output goals. It's a model for other plants, as one can see in Fig 5.3 it has the lowest marginal cost of production at every price of fuel. Again this marginal cost is excluding non-fuel variable operation and maintenance costs because of the scarcity of such data, nonetheless as described above, these costs are far too small per MWh to

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[23] www.energy.ca.gov/sitingcases/delta/description.html
[24] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard

make up the differences in fuel costs except when fuel is at unrealistically low prices. As a result of its high efficiency and low emission rates, Delta Energy center ranks the highest on the competitiveness index among the critical electrical power plants.

AES Alamitos Generating Station

Industry Overview: AES, Alamitos Generating Station is a private electricity generating company operating under contract with Southland in Southern California. AES Alamitos first began operating in 1956[25]. The plant is located in Long Beach California and has six power generating units all located in close proximity to one another near the Los Cerittos Channel. The company has had a turbulent financial year due to environmental law suits and aging facilities and had to shut down some of its units in 2005 for repair and environmental upgrades, for this reason we shall be using 2004 data for this report. None the less AES is the third greatest electricity provider in Southern California. When the plant is operating at full output it is accountable for 3.3% of California's electrical capacity. See Table 1.16.2 for plant rank in MW capacity.

Production Statistics: AES Alamitos uses Natural Gas and Distillate Oil to produce electricity[26]. The plant uses 35,052,895 mmBtu to produce 3,019,127 MWh per year according to 2004 data. In comparison to the other plants in this report Alamitos is the least efficient energy producer of all the plants this report reviewed, producing the least electricity per mmBtu of input. Output, emissions, and efficiency are presented in Figure 1.16.8.

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[25] www.aes.com

[26] Ibid.

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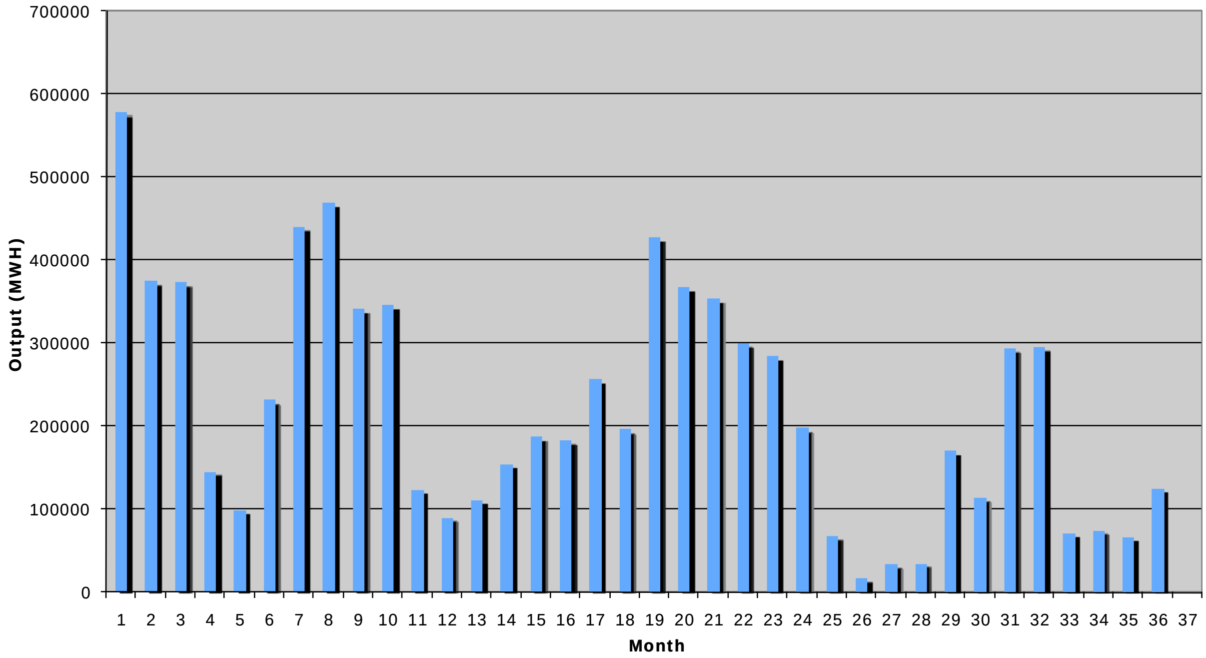
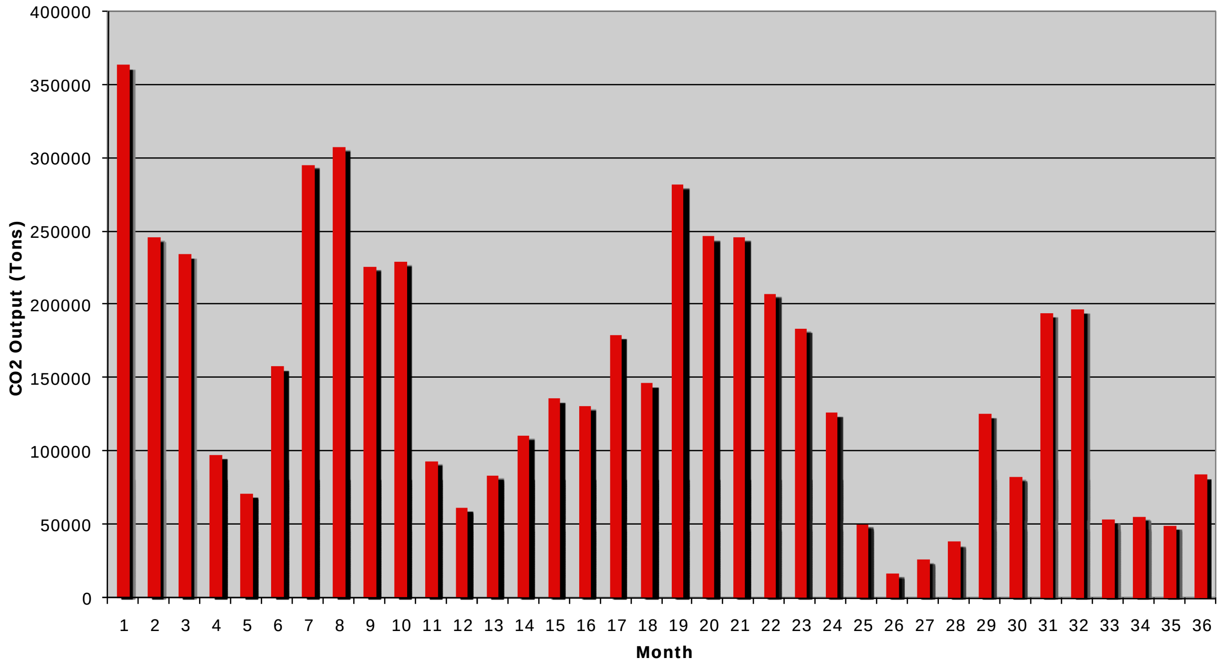
Figure 1.16.8: AES Alamitos

AES Alamitos Monthly Output



AES Alamitos Monthly Carbon Emissions '03-'05



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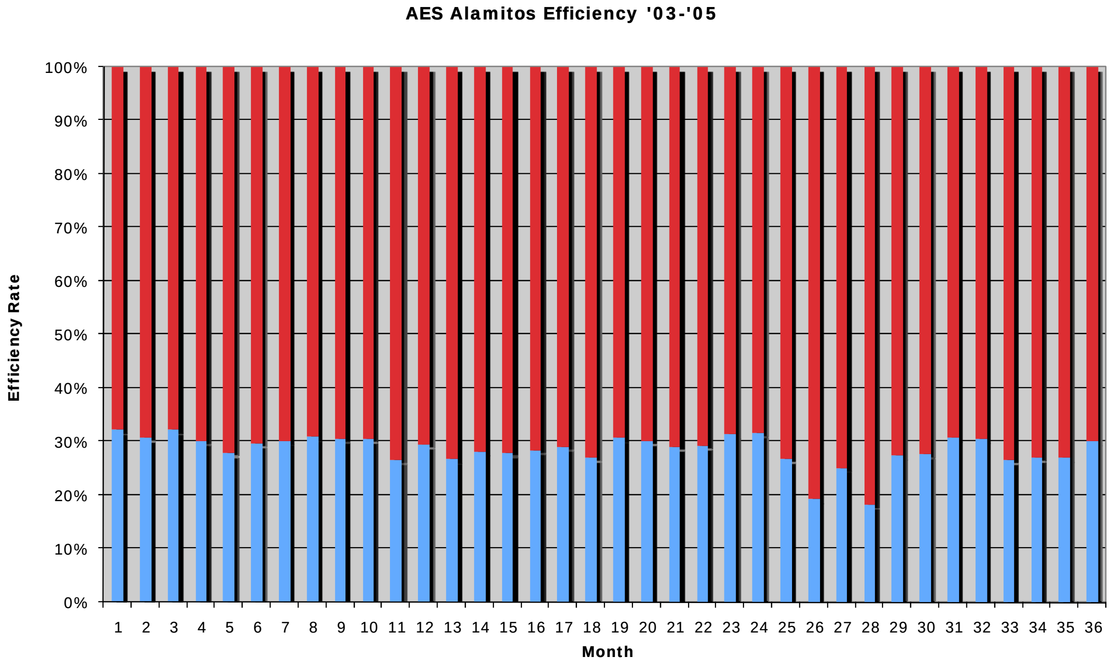

Technology: The low mmBtu to output ratio is primarily due to depreciation of infrastructure. The Alamitos units use conventional GE/Westinghouse steam turbines, Babcock and Wilcox Combustion Engineering boilers and Pratt & Whitney aircraft turbines[27] to generate electricity. The six generating units of Alamitos came online successively from 1956 through 1966. As a result their production is polluting, and costly (see Figure 1.16.6 and Figure 1.16.8 for output and plant efficiency) As a result of the lawsuits in 2005, efficiency information for that year may be inaccurate, however, their fuel efficiency average over three years comes out to 28.5% which puts them at the lowest average fuel efficiency for all plants in this report.

CO2 Emissions: AES produced 2,082,825.2 tons of CO2 in 2004 when all its units were in operation. In 2005 the CO2 emissions dipped to 974,950.4 and in 2006 with the increase in electricity output CO2 emissions rose to 1,406,909[28]. Though the company website says that it is in support of the California CO2 emission reduction they have yet to act upon their word and make changes towards lowering CO2 emissions at the AES Alamitos plant. Their emission to output (tCO2/MWh) ratios for these periods were: 0.786 in 2005 and 0.698 in 2004.

Costs and Competitiveness: AES Alamitos has been involved in various lawsuits concerning the environment. A record $17 million fine for excessive nitrogen oxide (NOx) emissions was

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[27] Ibid.
[28] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard

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imposed on Alamitos by the South Coast Air Quality Management (SCAQM) in 2000, in addition to the fine the company had to pay for the installation of expensive NOx reducing equipment[29]. The generating station was also fined for dumping hot water into the Los Cerittos river and disturbing aquatic life. Aside from legal costs, the Alamitos generating plant is highly vulnerable to price spikes in Natural gas. With such a low fuel efficiency capacity Alamitos emits far more CO2 and generates far less output than modern technology would allow. The AES Alamitos website claims that they are upgrading their capital though there are not any other reports to substantiate this claim. As a result of the high emission to output rate and low efficiency, Alamitos ranks as the least competitive major natural gas plants in the state in the competitiveness index introduced earlier (Figure 1.16.5).

Haynes Generating Station

Haynes Industry Overview: Haynes generating station is located in Long Beach and first came on line in 1962. It has 6 Units with a capacity of 1570 MW, supplying 2.5% of total California electricity capacity[30].

Production Statistics: Haynes's primary fuel is natural gas, of which it consumes 31,555,920 mmBtu to produce 3,786,978MWh in 2005. Also in that year, it installed new equipment which increase overall fuel efficiency, the new units came on line in 2005 and one can see the rise in productivity for all months in 2005 versus in the years 2004 and 2003 in the Figure 1.16.9 measuring monthly output, emissions, and efficiency, also take note of the efficiency rise. One can expect an even greater increase in fuel to output efficiency when as two additional units are expected to go online in 2008.

Technology: The Los Angeles Department of Water and Power (LADWP) invested in the modernization of two units at Haynes Generating Station. The new installations feature combined cycle units with cogeneration capacities. As a result, these new units have a much higher fuel efficiency rate (48%) then the older units of the plant that are still in operation which averaged about 30% efficiency in 2005, see efficiency graph in Figure 1.16.9. These numbers place the plant in a similar position as Moss Landing except for that Moss Landing modernized all of its base-load units whereas Haynes is still highly dependent on old technology, as a result the average fuel efficiency remains 40.6%. This may be changing

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[29] http://www.environmental-finance.com/2000/newsdec2.htm

[30] www.powermag.com/topplants/2005/Gas%20Oil_Avg%20heat%20rate.pdf?S=n

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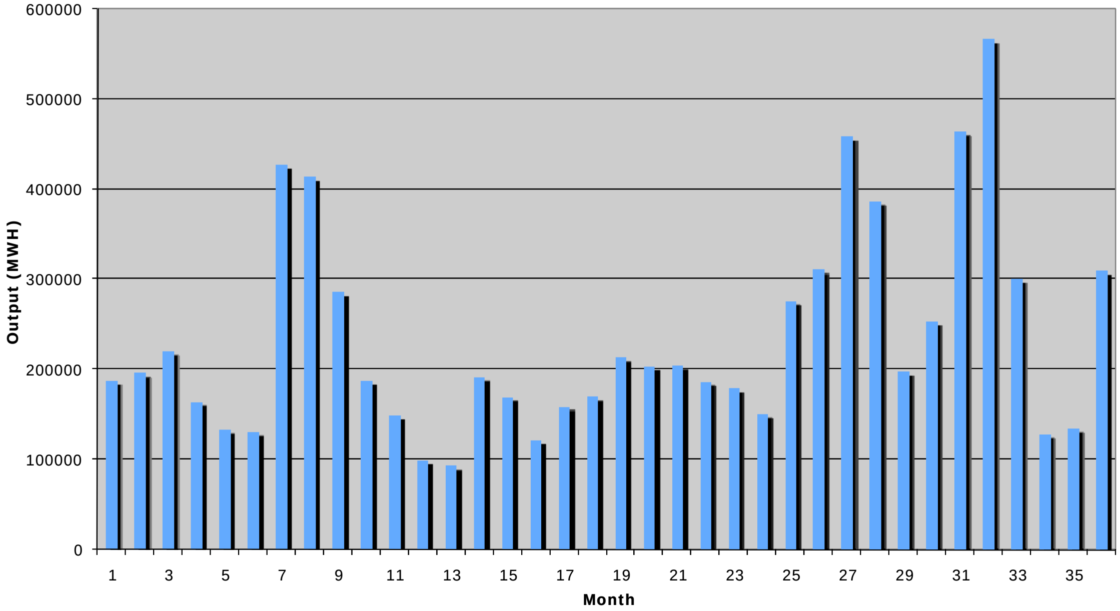
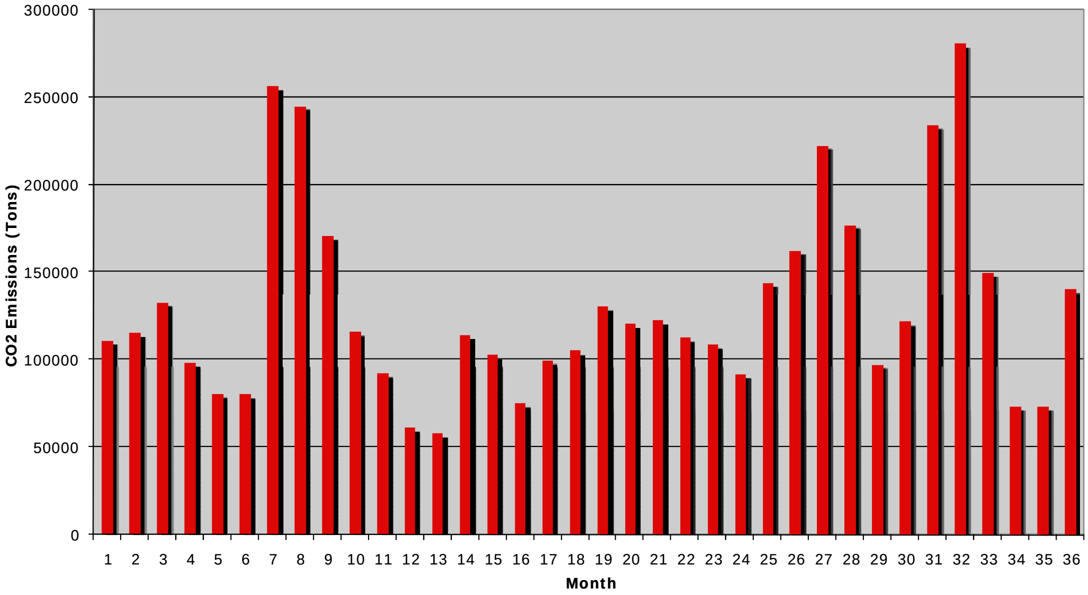
however as LADWP also plans to renovate generators 5&6 by 2008[31] and has increased investment in developing renewable energy resources.

Figure 1.16.9: Haynes Generator

Haynes Generator Output '03-'05



Haynes Generator CO2 Emissions '03-'05



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[31] Business Wire, April 15th, 2005. http://www.findarticles.com/p/articles/mi_m0EIN/is_2005_April_14/ai_n13608801

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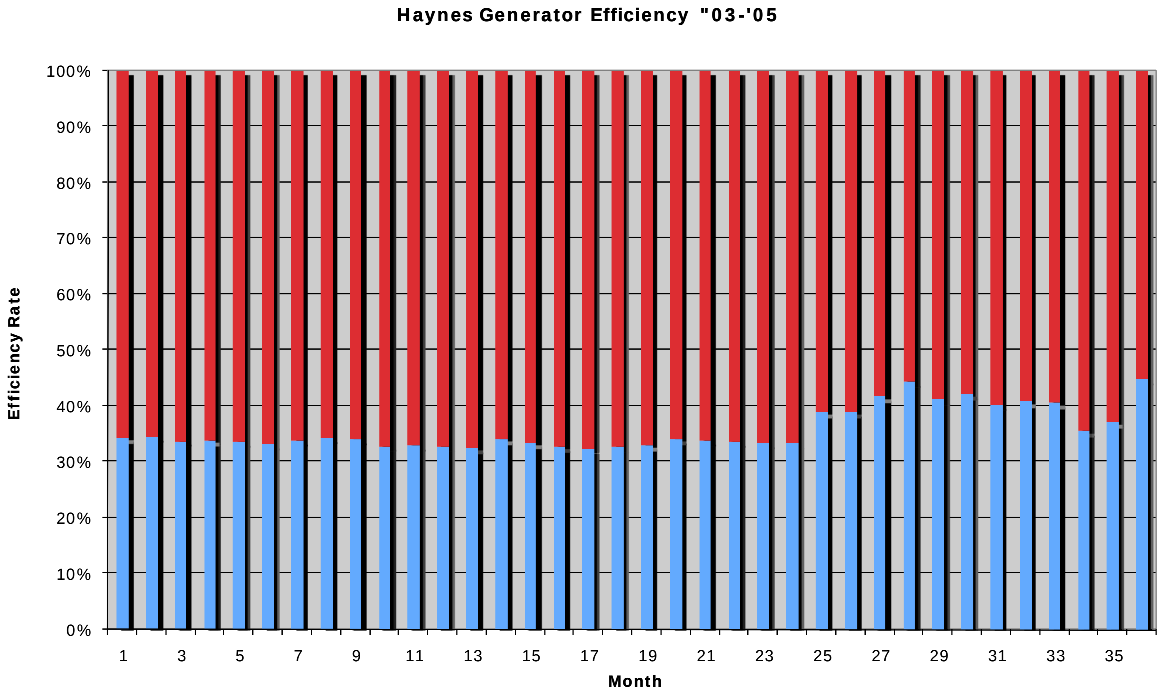

CO2 Emissions: Haynes emitted a total of 1,875,176.8 tons of CO2 in 2005,[32] which is about 5.9% of emissions by California electrical plants. The emissions graph in Figure 1.16.9 shows an increase in CO2 emissions in 2005, however this is just a reflection of higher MWh output. The efficiency of the plant has indeed gone up with the update of the two units and the ratio of total CO2 per MWh going down in 2005 from a 2003 yearly average of 0.6 to the 2005 average of 0.5. One can expect that the CO2 to MWh ratio will continue to go down with the addition of new technology in 2008.

Costs and Competitiveness: The costs involved in operating the newer units are far less than the older once again mostly because of savings from fuel efficiency. In this case however, it is not only due to fuel efficiency. The fuel required to power the new cogeneration turbines is actually cheaper at about 510 cents/mmBtu whereas the older turbines use a fuel 641.93cents/mmBtu to produce much less output. This results in a a marginal difference of almost 30 $/MWh that is saved by using the newer technology. Again, differences in operation and maintenance cost are present but difficult to get an exact measure on and relatively small compared to differences in marginal cost that result from differing fuel efficiencies.

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[32] www.epa.gov

Coal Plants: Mohave(NV) and Intermountain(UT)

Industry Overview: There are fewer coal-fired plants in California compared to the rest of the nation. Of the two major coal plants in the top 20 of generating capacity, both are out of state and one, Mohave Power Plant located in Nevada was shut down at the end of 2005. However, the data of both plants will be provided as examples of a "typical" coal plant. Mohave was owned partially by SCE before the shutdown and Intermountain, located in Utah is owned predominantly by the Intermountain Power Agency which is not located in California. However, the LADWP is a partial stakeholder.

Production Statistics: It is difficult to discern exactly how much of these plants' output is imported to California. However, coal powered generation makes a total of 9.8% of California's electricity. The two plants are nearly identical as their On-line MW capacity is 1640 MW for Intermountain and 1636 for Mohave. In 2005, it's last year of operation, Mohave Generating Station produced 11,093,073 MWh. At a similar level Intermountain produced 14,564,401 MWh.

The reason that Mohave and Intermountain produce a greater annual output than Moss Landing, California's largest plant, despite a lower MW capacity is that Mohave and Intermountain don't seem to exhibit a peaking cycle as do most of the gas-powered plants in California. If one looks at the output graphs, they produce at a relatively constant level throughout the year.

Technology: The technology used at Mohave was tangentially-fired processes with an electrostatic precipitator to control emissions. At Intermountain the type of unit is a dry-bottom, wall-fired boiler with a "baghouse" method of reducing emissions. The result was an average monthly efficiency of 36.9% over the last three years for Mohave and 33.6% for Intermountain. These efficiency rates are not as good as the newer and modernized natural gas plants such as Moss Landing and Delta, however it is more efficient than many of the gas plants.

Emissions: Mohave's total CO2 emissions for 2005 were The emission to output ratio for Mohave was 0.971 tCO2/MWh while Intermountain was a slightly larger emitter at 1.042. These are the highest ratios of any of the plants profiled in this report. However, that level is average for the type of fuel being used.

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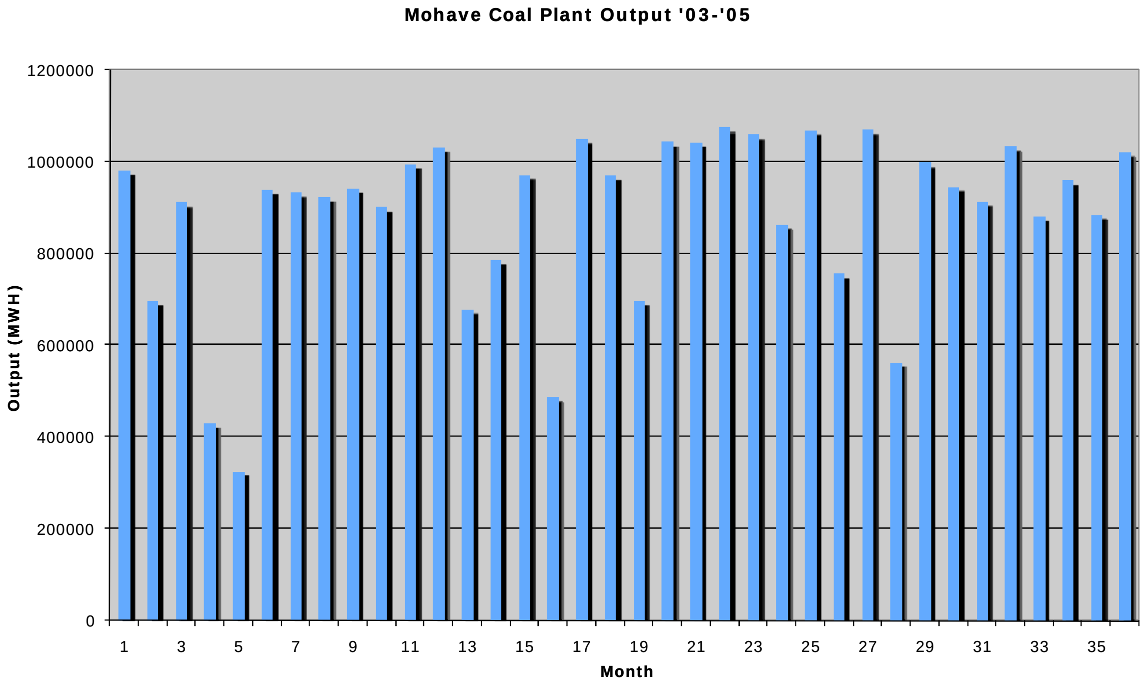
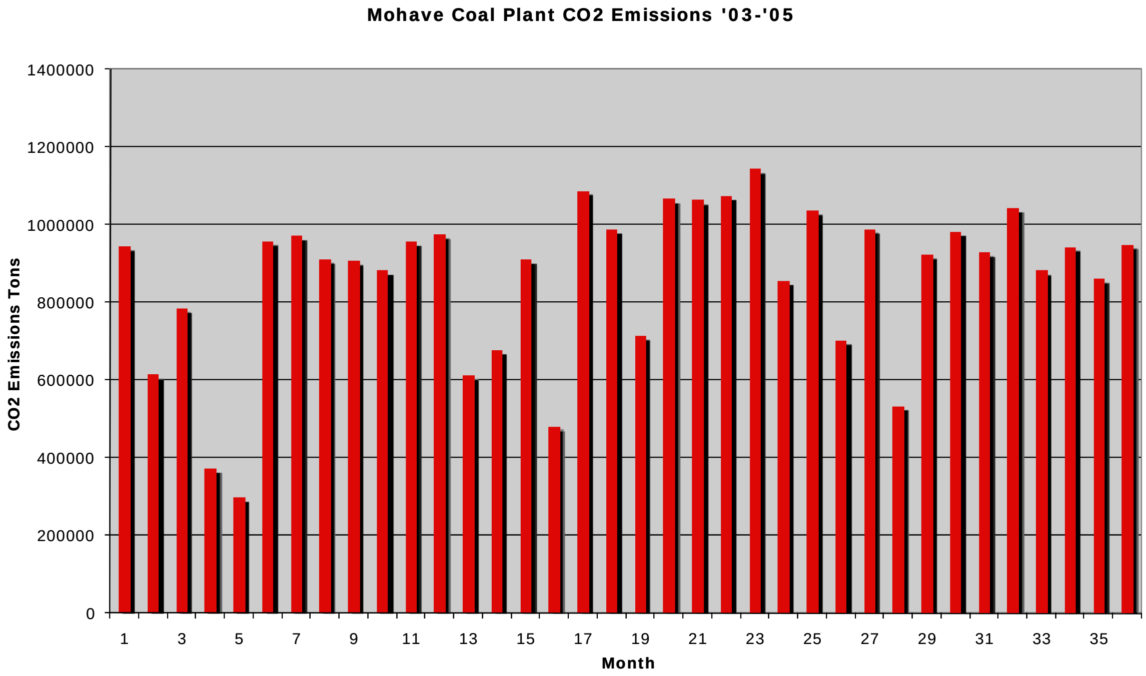
1.16.10: Mohave Coal Plant





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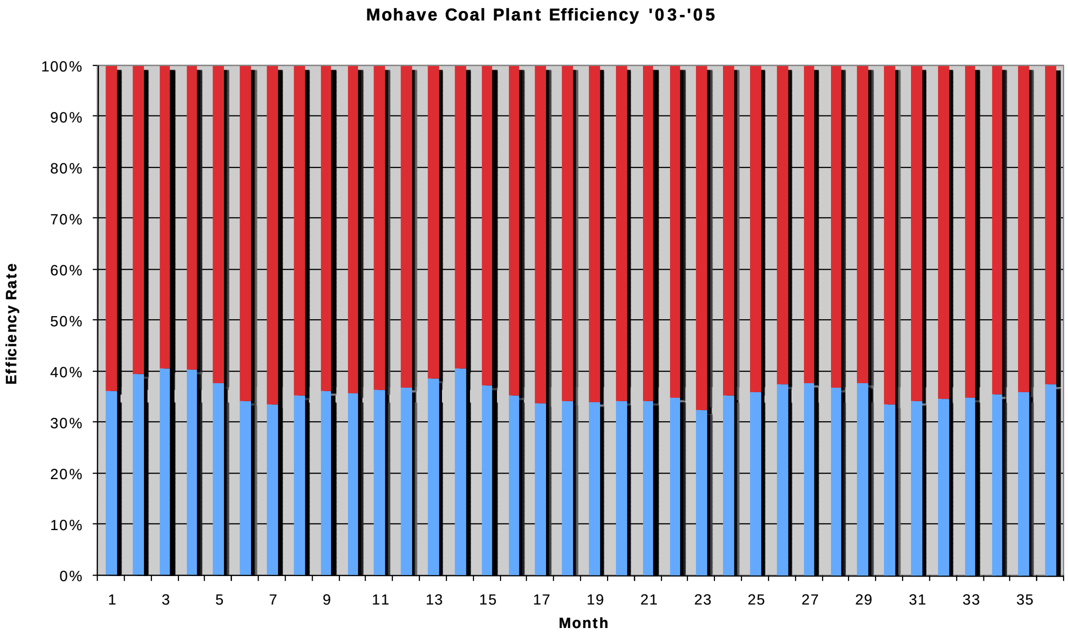

Costs and Competitiveness: At the April through June 2006 average price of $51.72/ton and the average yield of 12000 Btu/pound of central Appalachian coal, the average fuel price of production is $2.15/mmBtu. The marginal cost of fuel at the respective efficiencies of the plants is approximately $20/MWh. This is a much lower marginal cost of fuel than the natural gas fired plants. As a result, they are likely to remain competitive even with a tax on emissions which are an order of magnitude higher than the natural gas plants. Despite the low marginal cost of fuel, a strong cap on their emissions could push costs up enough to render these plants less competitive. As a result, they have the lowest rank of all plants on the competitiveness index.

Structural Transition in the Electric Power Industry

It is clear that the key to competitiveness in the future will be fuel efficiency and this factor will only become more decisive as GHG regulation becomes more stringent. In an environment of rising fuel costs, differences in this efficiency become burdensome for those who are realizing only 30% of the energy potential of their fuels. In a significant way, efficiency will intensify economic disparities between plants with different vintages of technology. This is good news for recent investors because it accelerates pay offs and rewards new adoption. Nonetheless, new investments will certainly be needed, and more so the more determined the regime of climate action policies. Only seven of the top 20 plants providing energy to California

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have come online since 1970 and two of those are the coal plants described above. Thus the top tier of energy providers to California is dominated by 35+ year old technology. As Moss Landing exemplifies, a technological upgrade can induce a 16.5% drop in absolute emission levels, accompanied by an 8% rise in absolute output. Thus if California wishes to achieve the emission goals set by AB32, the most likely path will not be major cutbacks in production but aggressive innovation and technology adoption.

Because the working life of these capital goods spans several decades, these adjustments will establish new baselines for emission intensity and accelerate the need for future efficiency improvements.

1.17 Cement Production In California

The cement industry is quite literally fundamental to California's infrastructure and the myriad of services provided by it, including transport facilities and commercial and residential infrastructure architecture. As such, it is one of the state's most important strategic sectors. The California cement industry employed around 2,000 workers in 2002 and $1 billion in direct revenue. Indirect employment, including concrete and ready-mix manufacture and distribution, is estimated at 19,000, with revenues approaching $4.1 billion (CEC:2005).

Cement production also makes significant contributions to GHG emissions in California, representing about 2.4% of statewide CO2 but less than 0.1% of GSP. Thus Cement is likely to be considered a first-tier emitter in the context of a prospective state carbon cap. Having said this, the sector has a variety of important and incentive compatible market options for GHG mitigation, including increased use of limestone Portland cement and (fly ash) blended cement, which have an estimated potential to contribute 70% of to a cumulative (over 2005-2025) reduction of 38 MMTCO2 reduction from all measures examined costing less than $10 per metric ton carbon equivalent (MTCE) (CCAP:2005). At the present time, the industry's largest individual customer, a public agency, is undecided about whether or not blended cement will meet its needs. This deadlock poses an important obstacle to the industry's strategy for meeting the state's own environmental objectives, and it also denies the cement market and essential precedent of adoption. The use of waste tires as fuel would permit an estimated additional emission reduction of 10% (Ibid.).

The Climate Action mitigation policies in the cement sector can make modest but important contributions to reducing statewide emissions. If all the above measures are adopted, about

2.5% of total emissions can be eliminated on an annual basis. At the same time, the direct and indirect macroeconomic and industry level effects of the first four polices are small but negative. In the cap and trade scenarios, we see a classic example of the challenge posed by structural transition. If incumbent firms in the industry merely pass on their increased cost, sectoral output and employment will be adversely affected. If cap and trade phase-ins include incentives for investment and technology adoption, both the sector and the state economy will again benefit.

Table 1.17.1 outlines final year real adjustments for the Cement industry, and these results significantly resemble Electric Power. As with the latter industry, significant GHG mitigation translates into notable cost/price pressure, but here less than one third the percentage increase, and only a 2% induced decline in the trend for industry output. Nonetheless, import penetration increases and export competitiveness is undermined by the new costs associated with the cap and trade system.

Greater sector inclusiveness in the cap reduces the adjustment burden for Cement, but not as much as it does for Electric Power. This is because fuel costs are a larger percent of total costs for Cement, and thus permit costs induce greater mitigation even when the cost of permits declines with larger and more diverse program coverage.

Table 1.17.1: Structural Adjustment in the Cement Sector

(percent change from Baseline in 2020)

	Scenario 2	Scenario 3	Scenario 4
	Group 1	Group 12	Group 123
Emissions	-55%	-43%	-34%
Price	6%	3%	2%
Output	-2%	-1%	-1%

It may also be worth noting that, even in the worst case scenario considered, cost escalation in this sector appear unlikely to threaten plant viability. By historical standards, the cement sector has endured much greater cost escalations from its primary input, energy fuels.

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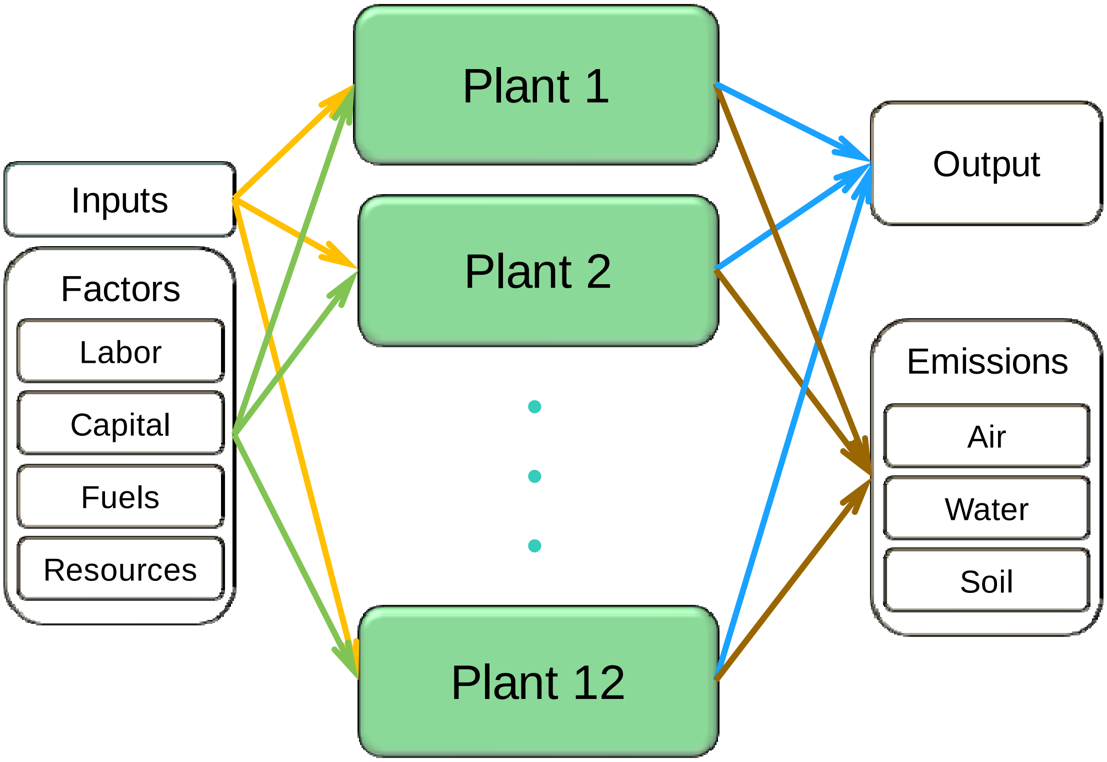
1.17.1 Modelling Approach

In contrast to the electric power sector, we consider only one tier of industrial structure, a set of twelve individual producers each with its own technology and cost structure. Schematically, the market structure of this sector is described in Figure 1.17.1: Schematic Structure of the Cement SectorFigure 1.17.1 below. Within the sector, each cement producer is represented by an individual plant that hires factors of production (labor, capital, energy) according to CES value added aggregations and uses intermediate inputs in Leontief constant (Input-Output) proportions to individual plant output (schematic Figure 1.17.2).

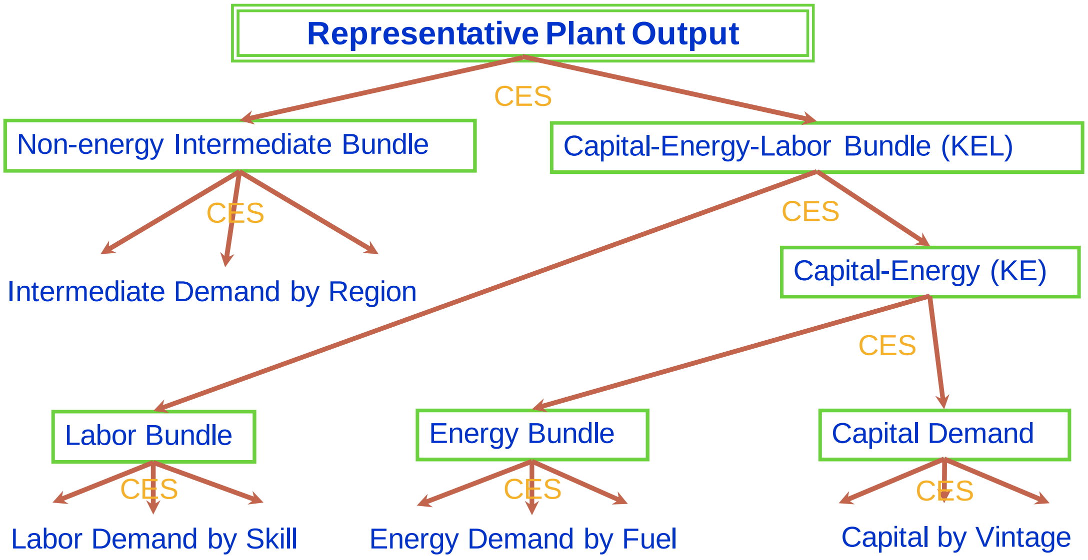
Figure 1.17.1: Schematic Structure of the Cement Sector



As we discuss later in this section intensive efforts were made to identify production calibration data at the plant level. Unfortunately, these were only partially successful, limiting the degree to which real or potential plant heterogeneity will influence structural adjustment in this sector. Improved data sources could sharpen the model’s ability to capture competitive differences and simulate their implications for sectoral adjustment patterns, but the data we have already obtained actually suggest that practical differences within the sector are limited.

Cost structures are broadly comparable, with similar incidence of fuel, raw material, and transport expenses. The primary remaining difference at the plant level is vintage of capital equipment.

Figure 1.17.2: Schematic Input and Factor Use for a Representative Cement Plant



Data Sources

In order to simulate this sector's response to state GHG mitigation measures, we begin with the Climate Action policy package proposed by CalEPA in January, 2006. The effects of this were estimated using industry Marginal Abatement Curves (MACs) devised by the Center for Clean Air Policy (CCAP:2005). At that time, a total of fourteen measures used by CCAP to construct their MAC curves were examined:

1. Limestone Blended Cement
2. Preventative Maintenance
3. Process Control & Management
4. Waste Tire Fuel
5. Clinker Cooler Control
6. On-line Kiln Feed Analyzer
7. Kiln Shell Heat Loss Reduction
8. Optimized Heat Recovery in Clinker Cooler

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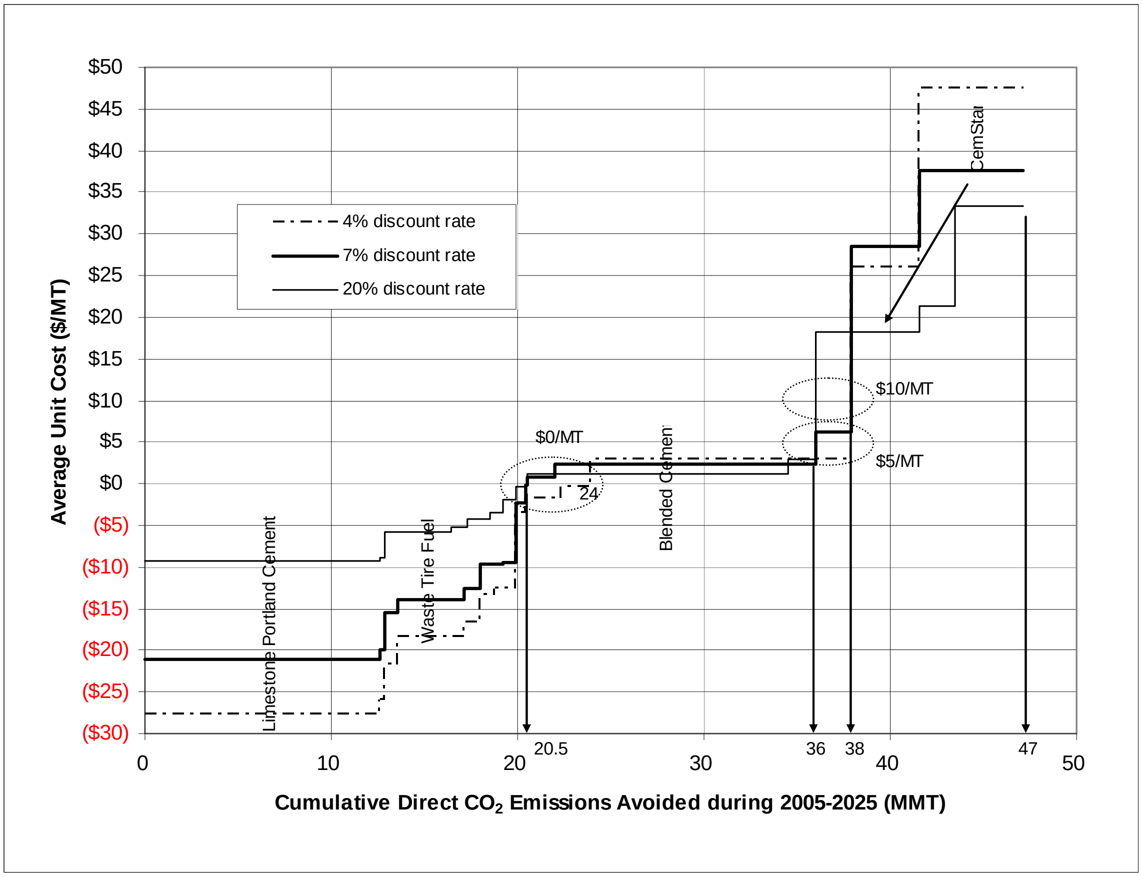
9. Precalciner on Dry Preheater Kiln
10. Planetary to Grate Cooler
11. Seal Maintenance
12. Blended Cements
13. Long Dry to Preheater, Precalciner Kilns
14. CemStar without License after 2014

Figure 1.17.3: Marginal Abatement Curve Estimates for Cement



Source: CCAP:2005

The primary data source is a report by the Center for Clean Air Policy (CCAP:2005a) and the spreadsheets that were used for their analysis (CCAP: 2005b), detailing Marginal Abatement Cost (MAC) estimates for over thirty measures in the cement sector. Costs were expressed in 2003 dollars, so no adjustment for BEAR was necessary. CCAP constructed three different MAC curves using discount rates of 4%, 7%, and 20%. To maintain consistency with the other types of measures used in BEAR, the 4% rate scenario was used as the basis for our analysis. An

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additional manipulation of the data was also necessary. The stream of GHG savings was discounted for purposes of recalculating the annualized abatement costs. Since only three of the fourteen measures exhibit positive costs at the 4% discount rate, this does not have much impact on the adoption of these measures by BEAR. Expenditures for equipment are mapped from the cement industry to the construction industry. Increased costs for improved maintenance procedures remain within the cement industry. This simulation was reported separately in more detail in Roland-Holst:2006.

1.17.2 Overview of Industrial Structure

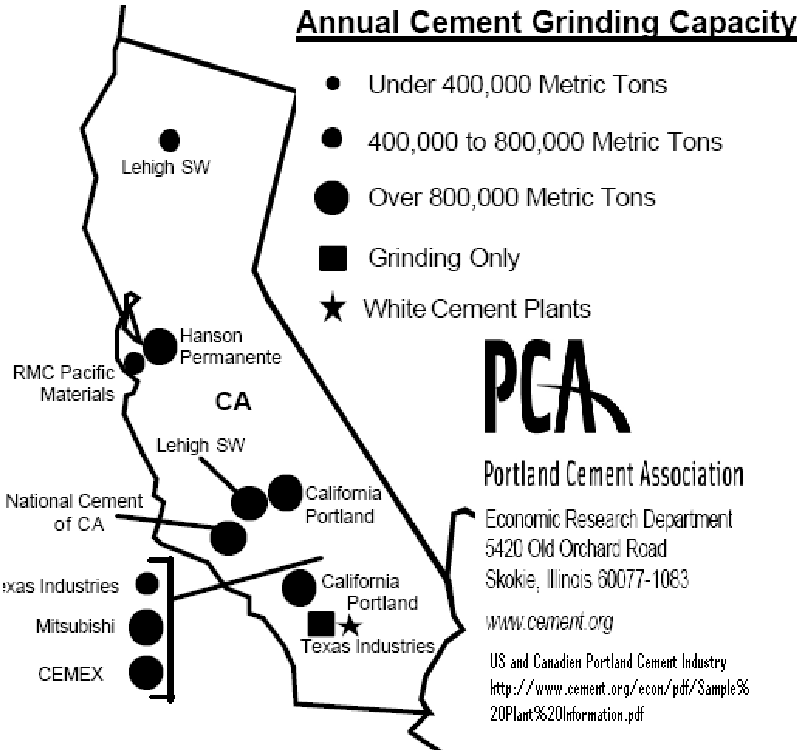
The state is currently relatively self-sufficient in cement, with production trending close to demand in the 10-15 MMT over the last five years. At the same time, the sector accounts for about 12 MMT of CO2 emissions, 88% of which arise directly from producing cement (concrete accounts for 11%) (CEC:2005).There are eleven major cement producing plants in the state and one grinding plant (Portland…A, 2004). These are distributed throughout the state, with one in Northern California, two in proximity to the Bay Area, and the rest distributed throughout Southern California (Figure 1.17.4). The state is responsible for 8-10 percent of national cement demand, and prices are generally above national averages (particularly in Northern California, see Table 1.17.2).

1.17.3 Cost determinants for cement producers in California

As with other economic activities that represent direct GHG emission sources, energy costs will be a primary determinant of the cement industry’s response to policies that restrict CO2 emissions. Because of its heat-intensive production technology, cement relies heavily on energy inputs, and together with raw materials these dominate variable costs in an industry where variable costs are more than half all operating expenses. Among energy costs, electricity represents over 10% of overall production cost, while natural gas can make up 1-5%, depending on choice of technology and alternative fuel (coal, tires, etc.). Labor is not a significant portion of production costs (Coito, et al, 2005 provides details on all these components.). A table from the 2002 census estimates the total cost and value of California cement shipments, and other industry statistics (Table 1.25.4).

Of special significance to the present discussion is transportation cost. The distribution of California cement plants depends on two primary factors: location of limestone (the principal raw material input) and market location. The latter is an essential consideration because of the low value/density ratio for this product. “Cement plants have substantial incentives to locate near the largest markets they serve" (Hanle, 2004). The *Regulatory Impact Report* comments on this feature of the industry: "The U.S. Portland cement industry is fragmented into regional markets rather than a single national market. Because of its low value-to-weight ratio, the relative cost of transporting cement is high and limits the geographic area in which each producer can supply its product economically. Since Portland cement is a homogeneous product, buyers are unable to distinguish between the product of sellers in the market so that the geographic bounds of each market are solely determined by the costs of transport. Generally, cement sales are made within a radius of 200 to 300 miles of each plant, with access to river transport allowing manufacturers or producers to expand beyond that radius. About 89% of US cement is shipped by truck (Regulatory…Rulemaking, 1998). " Hendrik Van Oss estimates freight costs to range from $10-30 per ton. These are sometimes borne by concrete manufacturers, who pick up the cement directly from the plants (Personal…Van Oss, 2006).

Figure 1.17.4: California Cement Production Facilities and Levels



© 2004 Portland Cement Association

Table 1.17.2: California Output and Price Indicators

		Quantity (MT)	Percent	Price ($/MT)	Ratio
2003	**N. California**	3,751	2.34	80.69	110
	S. California	9,881	6.18	74.97	102
	U.S.	160,000	100.00	73.50	100
2004	**N. California**	4,257	3.70	86.88	111
	S. California	10,764	9.36	81.87	105
	U.S.	115,000	100.00	78.00	100

Source: Van Oss: 2004.

Because of its geographic extent, California mirrors this national framework, with markets segmented into Northern and Southern regions (see again Figure 1.17.3). The Bay Area and Sacramento region are separated from the Los Angeles basin and San Diegoby more than the maximum efficient radius, and maritime transport is not generally considered an attractive option for bridging these markets. This may in part explain the persistent price differences between the two markets (Table 1.17.2). Finally, California is relatively isolated from other metropolitan markets, the nearest being Portland and Phoenix, both more than 500 miles from the nearest of the two California markets. These considerations exert important limitations on the industry's ability to re-locate in response to changing market and regulatory conditions.

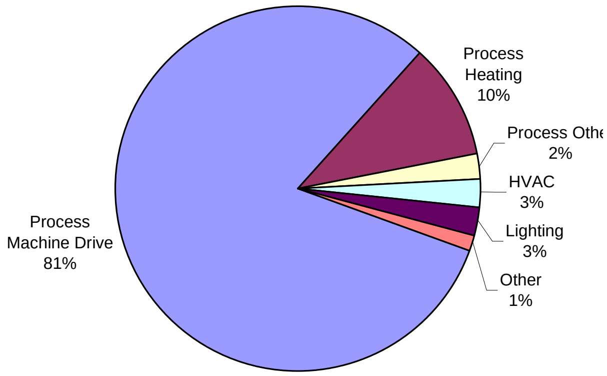
From the industry perspective, Chairman of PCA and CEO of California Portland James Repman commented in an interview that chronic cement shortages and an inability to satisfy consumer demand in the short term.[source] Levels of demand have exceeded all expectations and forecasts, and ability to import has been seriously constrained by freight and shipping costs. Repman notes further limitations to shipping, such as the unreliability and limited availability of rail systems (something that will not change without substantial investments in infrastructure), and the prohibitive costs of trucking. (Cement Americas, 2004) The California cement market has seen a downturn recently, and growth is expected to slow (Tables 1.17.4 and 1.17.5 provide more detail on this).

1.17.4 General Emissions and Energy Use

An extensive review of the literature on California's cement production has revealed a number of salient characteristics. Overall, the cement manufacturing process uses energy at four stages: raw material preparation, clinker production, and finish grinding. The first of these steps is the most electricity-intensive, requiring generally about 23-32 kWh/short ton, although it could require as little as 10 kWh/short ton (Coito, et al, 2005) (see also Figure 1.17.4) The kiln process produces so called clinker, the solid feed stock for grinders that produce finished cement. Portland cement clinker is made by heating, in a kiln, an homogenous mixture of raw materials to a sintering temperature, which is about 1450°C for modern cements (Taylor: 1990). Clinker production is the most energy-intensive stage in cement production, accounting for over 90% of total industry energy use, and virtually all of the fuel use (Coito, et al, 2005). Due to the very high temperatures reached in cement kilns, a large variety of fuel sources can be used to provide energy. Coal is responsible for the largest share of energy consumption at cement kilns, approximately 71% in 2001. Approximately 12% of energy consumption is derived from petroleum coke, 9% from liquid and solid waste fuels, 4% from natural gas, and the remainder from oil and coke (Hanle, 2004).

Dry kilns require more electricity to operate due to the need for fans and blowers; however, they consume significantly less energy fuels for heating. On average, the wet process has been estimated to require 6.3 Million Btu per short ton (MBtu/st) versus 5.5 MBtu/st for the dry process (Hanle, 2004).

Figure 1.17.4: Cement Industry End Use Electricity Consumption



Source: 1998 MECS (Manufacturing Energy Consumption Survey)

CO2 is emitted in three stages of cement production (1) fuel combustion, typically coal, in cement kilns, (2) offsite and onsite power generation, and (3) in the clinker-making process. Total emissions, including from transportation are estimated to be 10.4 Mt CO2 (2.8 MtC). [...] In the United States Average emission intensity for cement making is estimated to be 1047

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kgCO2e/t cement, which includes mining and transport of raw materials (PIER: 2005). Emissions from clinker production account for nearly half of CO2 produced (Van Oss, personal communication).

On a national basis, the cement industry is becoming increasingly concentrated, with a few multinational cement companies assuming ownership of increasing shares of cement manufacturing capacity. A similar trend is apparent in CO_2 emissions, where it has been estimated that five companies were responsible for roughly 50% of CO_2 emissions from the U.S. cement industry, and the top ten accounted for nearly 70% of emissions (Hanle, 2004).

The California cement industry is a major energy consumer, with annual (2002) demand for 1,600 GWh of electricity, 22 million therms of natural gas, 2.3 million tons of coal, and smaller amounts of coke and waste materials including tires. This represents about 5% of electricity consumption and 1% of natural gas consumption for all of California industry (Coito, et al, 2005). (See 1.17.6 for *General Plant Energy Usage* Energy Institute Estimates).

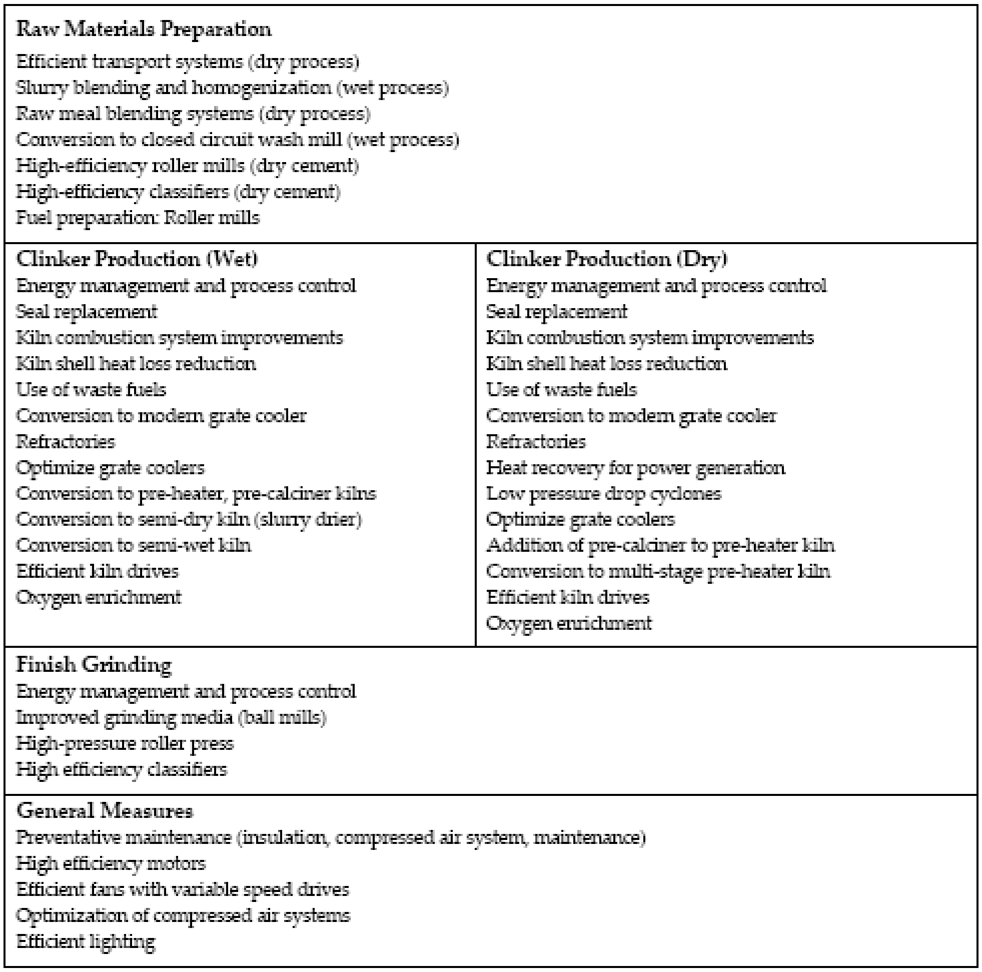
1.17.5 General Emissions Reduction Opportunities

Because of the dominant cost represented by kiln fuel consumption, energy efficiency must be recognized as a primary means of improving both production efficiency and GHG mitigation in the cement sector. The main energy-efficiency opportunities in the kiln are conversion to more advanced technologies (i.e., pre-calciner multi-stage pre-heater kiln), optimization of clinker cooling, improvement of preheating efficiency, improved burners, and process control and management systems. Electricity use can be reduced through improved grinding systems, high-efficiency classifiers, high-efficiency motor systems, and process control systems. Table 1.17.3 provides a list of energy-efficient practices and technologies for cement production, including (but not limited to) those set forth by the CalEPA Climate Action Team (Coito, et al, 2005; Worrell and Galitsky, 2004).

In personal communication, Handrik Van Oss noted that the opportunities for reducing emissions from burning limestone (clinker production), a source representing nearly half of cement CO2 emissions, are limited. CO2 fumes from kilns are ‘diffuse’, i.e. bundled with a host of other emissions, making filtration very expensive. He believes more cost effective improvements would either have to come from alternative fuels or blended cements. He further noted that, if the industries producing fly ash or slag are regulated, the costs of these might increase dramatically, leaving the cement industry with fewer options for cost effective emission reduction. It can also be noted that waste derived fuels, such as from tires, also could contribute significantly to emission reductions.

The blended cement issue is further complicated by an impasse with the industry's largest customer, a public transportation agency. CalTrans has not yet determined that blended cement meets is general design specifications for transport infrastructure. An adverse decision in this context would seriously limit the profitability of investments in blending technology, reduce the scope of emission/efficient cement sales, and deny the industry a very important market and engineering standards precedent.

Table 1.17.3: Energy Savings Opportunities in Cement Production



Raw Materials Preparation Efficient transport systems (dry process) Slurry blending and homogenization (wet process) Raw meal blending systems (dry process) Conversion to closed circuit wash mill (wet process) High-efficiency roller mills (dry cement) High-efficiency classifiers (dry cement) Fuel preparation: Roller mills	
Clinker Production (Wet) Energy management and process control Seal replacement Kiln combustion system improvements Kiln shell heat loss reduction Use of waste fuels Conversion to modern grate cooler Refractories Optimize grate coolers Conversion to pre-heater, pre-calciner kilns Conversion to semi-dry kiln (slurry drier) Conversion to semi-wet kiln Efficient kiln drives Oxygen enrichment	**Clinker Production (Dry)** Energy management and process control Seal replacement Kiln combustion system improvements Kiln shell heat loss reduction Use of waste fuels Conversion to modern grate cooler Refractories Heat recovery for power generation Low pressure drop cyclones Optimize grate coolers Addition of pre-calciner to pre-heater kiln Conversion to multi-stage pre-heater kiln Efficient kiln drives Oxygen enrichment
Finish Grinding Energy management and process control Improved grinding media (ball mills) High-pressure roller press High efficiency classifiers	
General Measures Preventative maintenance (insulation, compressed air system, maintenance) High efficiency motors Efficient fans with variable speed drives Optimization of compressed air systems Efficient lighting	

Source: Worrell and Galitsky (2004)

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1.17.6 California Specific Emissions Reduction Opportunities

Opportunities specific to California have been investigated by several independent parties. The CCAP (2005) study found that nearly 2 MMTCO2e could be reduced annually from measures costing less than $30 per metric ton (1.8 MMTCO2e in 2010 and 1.9 MMTCO2e in 2020). One-half (over one MMTCO2e) of the annual reductions would be obtained from measures that would produce a net cost savings, including the use of limestone Portland cement (0.6 MMTCO2e and 0.7 MMTCO2e in 2010 and 2020, respectively). Blended cements would account for about 0.7 MMTCO2e in 2010 and 2020, at a cost of less than $5 per metric ton. An additional 0.18 MMTCO2e/year of reductions could be achieved cost effectively by replacing coal with waste tire as a boiler fuel, but this option is not included because local community opposition makes it an unlikely option. Using similar data, an independent economic analysis estimates that emissions reductions by the cement industry accounting for 2.5% of statewide carbon emissions would have small, but negative macroeconomic effects (Roland-Holst, 2006).

In their comprehensive survey of the industry and management practices, Coito et al (2005) identified three general opportunities for reduced energy use:

1. *Operations and maintenance* (*O&M)*: finds that primary emphasis is on maximizing production through continuous operation, and less emphasis on minimizing costs and better efficiency.

2. *High efficiency equipment/processes*: self explanatory

3. *Controls*: Key opportunities for improved process controls involve clinker production and finish grinding, as well as operation of compressed air systems.

An interview with four “key plant managers” representing 5 plants revealed the following relevant information (Table 1.17.4):

- Managers believed the following factors to be critical to their businesses success: environmental regulations, market conditions, and energy costs….but implementing energy cost savings was less important.

- One reported “maintaining consistent production and product quality is the overriding concern. Although everyone at the plant is aware of energy […] we have limited operating staff[…] Also, the plant must remain in production as much as possible. The interruptions and coordination required for retrofits can also restrict consideration of energy retrofits.”

- Managers demanded very high returns to justify capital investments- 1 to 1.5 years for low and 2-3 for high efficiency plants.

- Two managers claimed to have policies in place to ensure higher energy efficiency on new investments, one demanded that new investments at least maintain standards, and one had no policy in place. Only 1 plant had an employee designated to monitoring energy efficiency.

Key limitations to greater efficiency were specified: limited energy efficient capital availability, production concerns (interrupting production), limited staff time (top priority to "keep things running"), concerns about reliability of new investments or overhauls etc. "The smaller energy-efficiency items at these facilities can amount to fairly large savings but don't get addressed because they are considered a hassle."

Table 1.17.5: Rating of Key Business Factors
(0 = Unimportant, 5 = Extremely Important)

Business Factors	Average Ranking
Meeting regulatory requirements (such as environmental requirements)	5.0
Meeting your production schedule	4.5
Maintaining product quality and consistency	4.3
Keeping up with new or shifting market demands	3.3
Having a reliable, high quality supply of electricity	3.3
Maintaining your market niche	2.5
Keeping up technologically with competitors	2.3
Maintaining a happy and productive staff	2.3
Identifying and implementing cost saving measures	1.3

Source: Coito et al, 2005

Coito et al summarize their findings in this way: “In general, the tone of interview was that managers were dedicated to ensuring a smooth production process and didn’t have the time nor resources to give serious concern to energy efficiency.”

1.17.7 Individual Plant Survey

A plant by plant review of the industry reveals diversity of scale and some product characteristics, but the primary drivers of capacity use and cost do not appear to be very heterogeneous across this industry. Twelve cement plants operate in California, eleven of which are integrated plants, operating both kilns and grinding mills. One plant operates only grinding mills. Eleven produce grey cement, and one produces white. Twenty-seven percent of integrated plants produce at least some blended cement. Ninety one percent (10) of plants had an onsite quarry. Sixty four percent (7) had precalciners and nine percent (1) had preheaters.

Thirty six percent (36%) of plants (4) used some quantity of waste fuel, and eighty five percent of kilns used coal as their primary fuel. Mean kiln inception year was 1969 with a standard deviation of seventeen (17) years. Median kiln vintage was 1962 while mode kiln vintage was 1981. The most recent kiln renovation was 2001, though Texas Industries Oro Grande plant has contracted to begin construction on a new kiln. The oldest kiln was from 1948.

Average Kiln Age weighted By tonnage is 1983. Average vintage of kiln, omitting Texas Industries Crestmore ll and Oro Grande (outliers) was 1982. Seventy-three (73%) percent of plants had kilns from 1980 or later, up to eighty-two (82%) including the planned Oro Grande plant. Average tonnage per kiln was 620 (thousand tons).

According to confidential sources at the Energy Institute, kilns are estimated to be operating at near 100% capacity due to chronic cement shortages. Private discussion with Hendrik Van Oss reinforced this impression, though his 2004 report related levels closer to 90% (Personal…Van Oss, 2006; Van Oss, 2004).

The following table summarizes the salient structural features of California’s cement production facilities.

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Table 1.17.6: Inventory of California Cement Facilities

1. Mitsubishi Cement Corporation 5808 State Hwy. 18 Lucerne Valley CA 92356
H. O. Biggs (760) 248-7373
http://www.mitsubishicement.com/ (not active)
http://www.mitsubishicorp.com/en/network/us/america.html
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalciner (C) Preheater (X) Neither (N): C
Roller Press: Y
Number of Kilns: 1
Average Age of Kilns: 1982
Most Recent Kiln: 1982
Mean Kiln Clinker Capacity/Production (Thousand Tons): 1543
Total Kiln Clinker Capacity/ Production (Thousand Tons): 1543
Number of Mills: 4
Average Age of Mills: 1965.5
Most Recent Mill: 1982
Mean Mill Cement Capacity (Thousand Tons): 446.75
Total Mill Cement Capacity (Thousand Tons): 1787

2. CEMEX 16888 North E. Street Victorville CA 92392
Craig Gotro (760) 381-7600
http://www.cemexusa.com/index.asp
http://finance.yahoo.com/q/pr?s=CX
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): X
Roller Press: Y
Number of Kilns: 2
Most Recent Kiln: 2001
Average Age of Kilns: 1992.5
Mean Kiln Clinker Capacity/Production (Thousand Tons): 1363.5
Total Kiln Clinker Capacity/ Production (Thousand Tons): 2727
Number of Mills: 5
Average Age of Mills: 1974.8
Most Recent Mill: 2001
Mean Mill Cement Capacity (Thousand Tons): 630.8
Total Mill Cement Capacity (Thousand Tons): 3154

3. Hanson Permanente Cement 24001 Stevens Creek Blvd Cupertino CA 95014
Stewart B. Smith (408) 996-4271
http://www.hanson.biz/
http://biz.yahoo.com/ic/110/110781.html
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: Y
Number of Kilns: 1
Average Age of Kilns: 1981
Most Recent Kiln: 1981
Mean Kiln Clinker Capacity/Production (Thousand Tons): 1497
Total Kiln Clinker Capacity/ Production (Thousand Tons): 1497
Number of Mills: 3
Average Age of Mills: 1992.67
Most Recent Mill: 1996
Mean Mill Cement Capacity (Thousand Tons): 604.67
Total Mill Cement Capacity (Thousand Tons): 1814

4. California Portland Cement Co. 9350 Oak Creek Road Mojave CA 93501
Bruce Shafer (805) 824-2401
http://www.calportland.com/
http://www.calportland.com/Mojave/Mojave.htm
California Portland Cement sells 6 million tons of cement, 3 million yards of concrete, and 8 million tons of aggregates, which are worth nearly $1 billion in annual sales.
Reduced energy use by 3% in 2004 and overall carbon emissions by 27,200,000.
“The California Portland Cement Company's Mojave Plant employs 150 people to extract limestone and produce cement at a 9,000 acre site (Center…Interpretation).”
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1981
Most Recent Kiln: 1981
Mean Kiln Clinker Capacity/Production (Thousand Tons): 1363

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Total Kiln Clinker Capacity/ Production (Thousand Tons): 1363
Number of Mills: 7
Average Age of Mills: 1961.57
Most Recent Mill: 1996
Mean Mill Cement Capacity (Thousand Tons): 1511
Total Mill Cement Capacity (Thousand Tons): 215.86

5. Texas Industries Inc. 19409 National Trails Hwy. Oro Grande CA 92368
http://www.txi.com/
http://finance.yahoo.com/q?s=txi&d=v2
"A 50-year-old 1.3 million ton per year cement plant that operates seven kilns is being replaced by a new 2.3 million ton per year single kiln line. The kiln line includes a 400-foot-tall preheater/precalciner and is being supplied by equipment vendor Polysius Corp. of Georgia." (The…Report, 2006) Confirmed by personal interview with H. van Oss (Personal…Van Oss, 2006)
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): N
Roller Press: N
Number of Kilns: 7
Average Age of Kilns: 1952.29
Most Recent Kiln: 1959
Mean Kiln Clinker Capacity/Production (Thousand Tons): 155
Total Kiln Clinker Capacity/ Production (Thousand Tons): 1085
Number of Mills: 5
Average Age of Mills: 1952.2
Most Recent Mill: 1960
Mean Mill Cement Capacity (Thousand Tons): 156.4
Total Mill Cement Capacity (Thousand Tons): 782

6. National Cement Co. Of California Highway 138, 5 Miles East of I-5 Lebec CA 93243
Byron McMichael (661) 248-6733
http://www.vicat.com/
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coke
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1999
Most Recent Kiln: 1999
Mean Kiln Clinker Capacity/Production (Thousand Tons): 1033
Total Kiln Clinker Capacity/ Production (Thousand Tons): 1033
Number of Mills: 3
Average Age of Mills: 1980.67
Most Recent Mill: 2001
Mean Mill Cement Capacity (Thousand Tons): 538
Total Mill Cement Capacity (Thousand Tons): 1614

7. Lehigh Southwest Cement Company 13573 Tehachapi Blvd. Tehachapi CA 93561
Ed Watamaniuk (661) 822-4445
http://www.lehighsw.com/
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1991
Most Recent Kiln: 1991
Mean Kiln Clinker Capacity/Production (Thousand Tons): 958
Total Kiln Clinker Capacity/ Production (Thousand Tons): 958
Number of Mills: 2
Average Age of Mills: 1981.5
Most Recent Mill: 1992
Mean Mill Cement Capacity (Thousand Tons): 408
Total Mill Cement Capacity (Thousand Tons): 816

8. Cemex Davenport 700 Highway One Davenport CA 95017
Satish H. Sheth (831) 458-5700
http://www.cemexusa.com/index.asp
http://www.cemexusa.com/ce/ce_pl_da.html
http://finance.yahoo.com/q/pr?s=CX
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1981
Most Recent Kiln: 1981
Mean Kiln Clinker Capacity/Production (Thousand Tons): 812
Total Kiln Clinker Capacity/ Production (Thousand Tons): 812
Number of Mills: 2
Average Age of Mills: 1981
Most Recent Mill: 1981
Mean Mill Cement Capacity (Thousand Tons): 428.5
Total Mill Cement Capacity (Thousand Tons): 857

Note: Purchased by Cemex from RMC for 5.8 billion in June 2004. Made CEMEX the world's leading concrete supplier. "An improved motor system allowed for savings of 2.4 million kwhs in 2004, and 1260 increase in tonnage per months. Because the newer motors have higher efficiencies (95%) than the ones they replaced, the blowers and cement pumps require less power to operate. Measurements of the motors' energy consumption show that the project has reduced energy use by 2,097,000 kWh and saves $168,000 in energy costs annually. These figures are consistent with the MotorMaster+ estimates. In addition, the plant is saving $30,000 in annual maintenance costs. A rebate from PG&E reduced the total project costs to $134,000, for a simple payback of 8 months (Cemex: Cement Manufacturer)."

9. California Portland Cement Co. 695 South Rancho Ave Colton CA 92324
D. M. Robertson (909) 825-4260
http://www.calportland.com/
http://www.calportland.com/General/cement.htm
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): N
Roller Press: N
Number of Kilns: 2
Average Age of Kilns: 1962
Most Recent Kiln: 1962
Mean Kiln Clinker Capacity/Production (Thousand Tons): 340
Total Kiln Clinker Capacity/ Production (Thousand Tons): 680
Number of Mills: 4
Average Age of Mills: 1971
Most Recent Mill: 1980
Mean Mill Cement Capacity (Thousand Tons): 268
Total Mill Cement Capacity (Thousand Tons): 1072

10. Lehigh Southwest Cement Company 15390 Wonderland Blvd. Redding CA 96003
James E. Ellison (530) 275-1581
http://www.lehighsw.com/
Type of Plant: Integrated
Type of Cement: Grey
Primary Fuel: Coal
Precalcinor (C) Preheater (H) Neither (N): C
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1981
Most Recent Kiln: 1981
Mean Kiln Clinker Capacity/Production (Thousand Tons): 592
Total Kiln Clinker Capacity/ Production (Thousand Tons): 592
Number of Mills: 3
Average Age of Mills: 1966.67
Most Recent Mill: 1980
Mean Mill Cement Capacity (Thousand Tons): 206.34
Total Mill Cement Capacity (Thousand Tons): 619

11. Texas Industries Inc., Crestmore II, Riverside CA
http://www.txi.com/
http://finance.yahoo.com/q?s=txi&d=v2
Type of Plant: Integrated
Type of Cement: White
Primary Fuel: Oil
Precalcinor (C) Preheater (H) Neither (N): N
Roller Press: N
Number of Kilns: 1
Average Age of Kilns: 1959
Most Recent Kiln: 1960
Mean Kiln Clinker Capacity/Production (Thousand Tons): 51
Total Kiln Clinker Capacity/ Production (Thousand Tons): 102

Number of Mills: 1
Average Age of Mills: 1958
Most Recent Mill: 1958
Mean Mill Cement Capacity (Thousand Tons): 122
Total Mill Cement Capacity (Thousand Tons): 122

12. Texas Industries Inc., Crestmore I, Riverside CA
http://www.txi.com/
http://finance.yahoo.com/q?s=txi&d=v2
Type of Plant: Grinding
Number of Mills: 3
Average Age of Mills: 1960
Most Recent Mill: 1960
Mean Mill Cement Capacity (Thousand Tons): 248
Total Mill Cement Capacity (Thousand Tons): 744

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1.17.8 How will Cement Manufacturers Respond to Adjustment Pressures?

The following key features of California's cement industry are relevant to the fate of its incumbent producers. Firstly, the demand for cement in California has remained high to the point that the industry reports supply shortages in each of the last three years (Cement Americas, 2004). This condition has persisted despite rising costs of fuel and transport, which have been passed on to consumers in the form of steeply increased prices, implying inelastic demand (Van Oss, 2004). From this experience one might infer that the size of the cement market in California should be relatively resilient to price increases induced by regulation, and that incentives to provide California with cement will remain strong. Still, various sources report that demand for cement has eased in recent months.

Will cement plants leave the state in response to the higher production costs arising from GHG regulation? This is depends on two factors: cost control and pricing power. In the first case, firms will need to shift resources to offset increased emission costs, which can be done with investments in more efficient technology, carbon sequestration, or increases in other forms of process efficiency. In the second case, firms may be able to pass on some induced regulatory cost in the form of higher prices. An overview of industry evidence suggests that there may be scope for both kinds of adjustment to limit pressure on long term industry profit margins. In some cases, such as energy efficiency, the same investments that reduce GHG liability also reduce energy cost. Investments in blending technology also fall into this category.

Returning to the original question of firm viability, it appears unlikely that any producers will emigrate in the near term, though if costs were high enough some might shut down. In the short term, leaving the state would mean forsaking substantial fixed asset investments. Within the very near future, 82% of California cement plants will have kilns built in 1980 or later (Portland…A, 2004). Kilns from 1948 are still in operation today even though they produce much higher energy costs that their designers envisioned and they achieve only 10% the level of newer plants, indicating to the enduring value of such investments. To construct a plant with a capacity of 1 million tons annually costs near $300 million, and a 2 million ton plant runs near $450 million. Kiln conversion or renovation costs over $50 million (Personal…Van Oss, 2006).

Could cement plants, in the long run, leave the state as their investments depreciate? It is unlikely that they might move to other states. Firstly, this argument assumes that other states will not ultimately follow California in upgrading environmental standards. Secondly,

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though quarries are disseminated throughout the US, high and rising transportation costs provide significant incentives for cement plants to locate near markets. The vast majority locate within 200 to 300 miles of major markets (Regulatory…Rulemaking, 1998). Moreover, industry leaders do not consider many long distance transport options to be reliable, especially US railways, resulting in further costs of doing business (Cement Americas, 2004; Hanle, 2004, Regulatory Impact, 1998). Finally, a long history of rising costs in this industry has established a consistent trend, price appreciation in line with competitive rates of return, coupled with investments in more efficient technology. There is no particular reason that GHG policies, if these lead to higher costs for today's producers, will induce different behavior patterns.

Van Oss notes that a greater danger than cement production leaving the state is cement production leaving the country, as sea shipping costs can be dramatically less than other forms of transportation. Still, there are other shortcomings to importing, such as scheduling issues that might undermine its cost effectiveness. Van Oss also believes that plants might respond to regulation by investing less than they would otherwise. This is especially relevant for the current regulation as plants must always run at full capacity (using energy), but investments are usually made for meeting future, not current, demand levels.

1.18 Oil Refining

Oil refining is a major part of the California economy, both in terms of output and employment, but also in terms of demand for its final products. The refining sector accounted for 5% of California manufacturing sales in 1997, and the sector employs nearly 10,000 people.[33] On the demand side, California is the largest consumer of gasoline in the U.S. (11.3% in 2004), and second largest consumer of the country's jet fuel (17.7%); 40% of California's 2003 energy consumption was used for transportation.[34]

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[33] Ernst Worrell and Christina Galitsky, 2004, "Profile of the Petroleum Refining Industry in California," LBNL-55450.

[34] Energy Information Administration (EIA) State Energy Profiles, online at: http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=CA#Con.

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Table 1.18.1: Structural Adjustment in the Petroleum Refining Sector

(percent change from Baseline in 2020)

	Scenario 2	Scenario 3	Scenario 4
	Group 1	**Group 12**	**Group 123**
Emissions	-46%	-36%	-28%
Price	6%	3%	2%
Output	-2%	-1%	-1%

Cap and trade effects in this sector are complex because of the diversity of its product stream, relatively low demand elasticities, and its pervasive linkages across the economy. In addition to its direct effluent potential, this sector is the primary channel for carbon fuels to reach the transport sector, so there are important feedback effects to refining from any measures that increase fuel efficiency elsewhere in the economy.

Despite its complexity, the industry results for petroleum refining aggregate to resemble those of a typical energy-intensive manufacturing sector. On an average basis, however, the experience of this sector is intermediate between that of the two already considered. Again we see the potential challenge and opportunity posed by structural transition. If incumbent firms must bear their entire share of the cost of a cap and trade scheme, their prices can be expected to rise 6% by 2025, with predictable effects on demand and supply. If instead they are part of an investment oriented policy package, price effects will be negligible.

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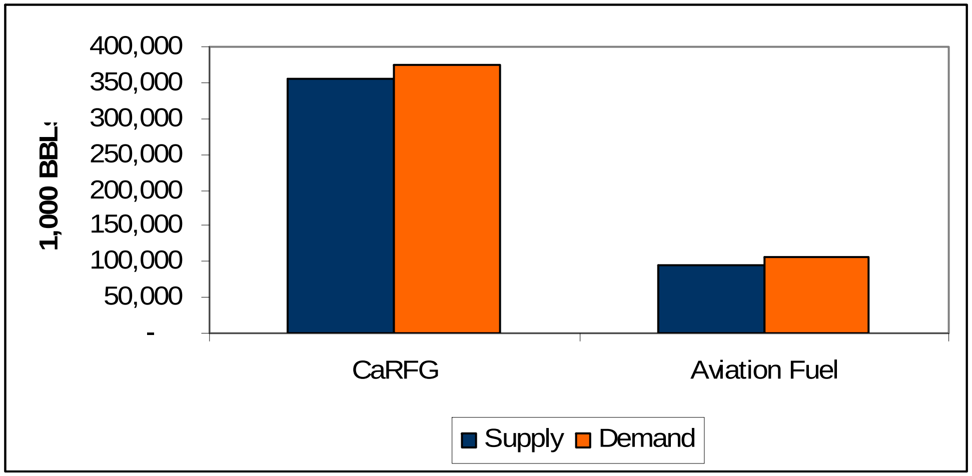
Meanwhile, the diversity of technology in this sector means that structural transition may create winners and losers among incumbent firms. This will depend upon the market power of individual refiners, as well as their ability to take advantage of investment incentives.[35]

Figure 1.18.1: California Gasoline and Aviation Fuel Supply and Demand



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[35] It should be emphasized that this sector is under very strict regulation regarding new capacity creation, and thus its ability to adopt new technology, even if the objective is greater energy/GHG efficiency, is open to question.

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Source: California reformulated gasoline and aviation fuel production data are from “Weekly Fuels Watch,” CEC, online at http://www.energy.ca.gov/database/fore/index.html ; demand data are from Energy Information Administration (EIA) State Energy Profiles, online at: http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=CA#Con .

At more than 2 million barrels (MBBLS) per day, California’s crude oil distillation capacity ranks third among U.S. states. In-state oil refineries supply most of California’s demand for refined oil products (Figure 1.18.1). Because of its higher product mix and California’s more stringent environmental standards, oil refining is more energy-intensive in California than refining in other states. Oil refining consumes more energy than any other sector in California.[36] As a fossil fuel-intensive industry, oil refining is a major source of California’s CO2 emissions.

1.18.1 California Refineries: Output

In 2006, 21 refineries operated in California, with a combined daily throughput of 2.022 million barrels of crude inputs. As Figure 1.18.2 shows, the 10 largest refineries accounted for nearly 84% of the state’s total refining capacity, with the largest 5 accounting for 54%.

California’s oil refining is concentrated in the Los Angeles Basin (LAB) and the San Francisco Bay (SFB) areas, with 6 of the state’s largest 10 refineries in the LAB region and 4 in the SFB region (Table 1.18.2). As Figure 1.18.2 shows, the 7 largest refiners account for 90% of total state refining capacity.

Figure 1.18.2: Refining Capacity and Percent Capacity in California, 2006

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[36] Worrell and Galitsky (2004).

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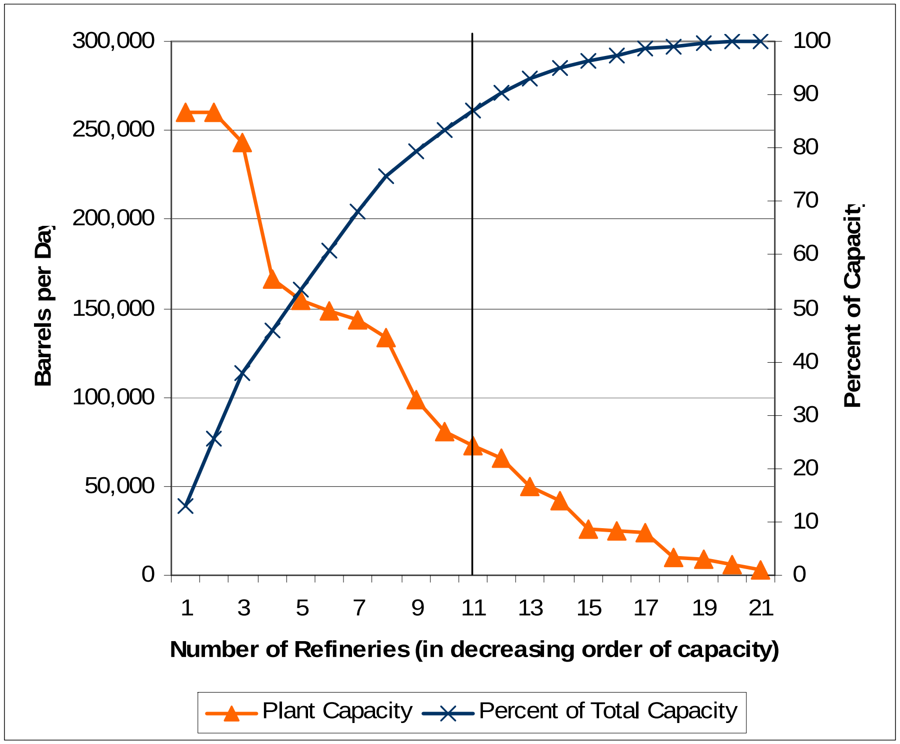

Source: “Oil and Petroleum in California,” California Energy Commission website, online at: http://energy.ca.gov/oil/index.html.

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Table 1.18.2: Refining Capacity in California by Region

Refinery	City	Capacity (BPD)	Region
BP West Coast Products LLC	Carson	260,000	LAB
Chevron 1	El Segundo	260,000	LAB
Chevron 2	Richmond	242,901	SFB
Tesoro, Golden Eagle	Rodeo	166,000	SFB
Shell	Martinez	154,900	SFB
ExxonMobil	Torrance	149,000	LAB
Valero	Benicia	144,000	SFB
ConocoPhillips,	Wilmington	133,100	LAB

Shell Oil Products US	Wilmington	98,500	LAB
Valero (Ultramar)	Wilmington	80,887	LAB

Source: “Oil and Petroleum in California,” California Energy Commission website, online at: http://energy.ca.gov/oil/index.html.

Figure 1.18.3: Top Refiners in California, Percentage of State-wide Production

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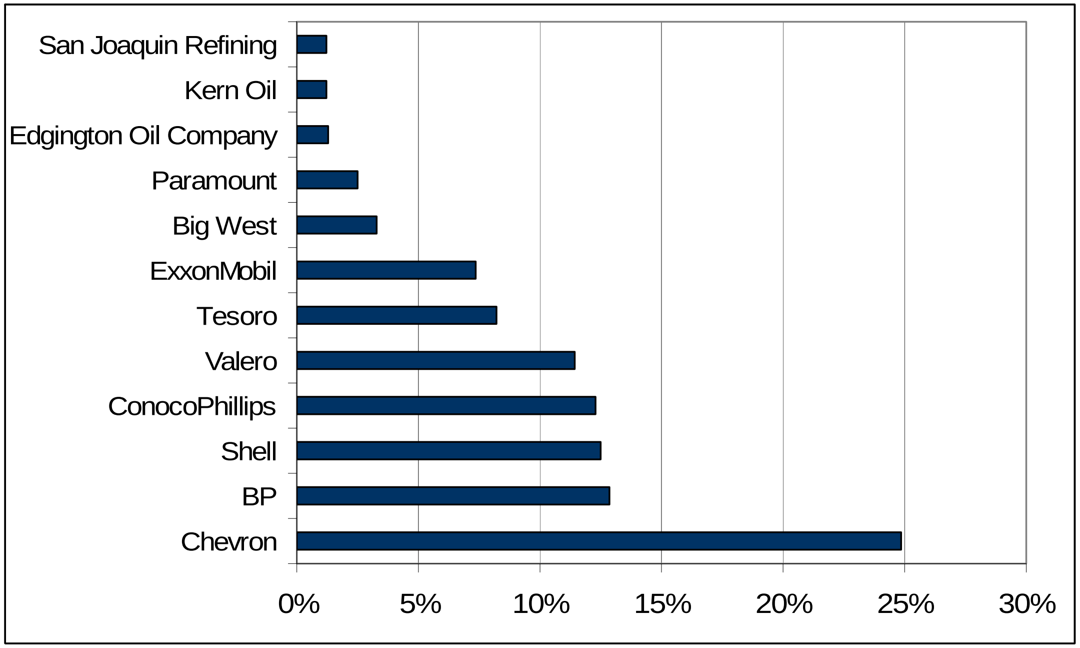

Source: “Oil and Petroleum in California,” California Energy Commission website, online at: http://energy.ca.gov/oil/index.html.

California crude inputs into and outputs from refining have remained relatively constant since 1999 (Figure 1.18.4). Refined outputs are typically classified into four categories: motor gasoline, jet fuel, distillate fuel, and residual fuel. Motor gasoline has accounted for about 60%, jet fuel for about 15%, and total distillates (mostly CARB diesel) for about 20% of the refined products tracked by the CEC. Reformulated gasoline accounted for 89 percent of total motor gasoline output over this time period.

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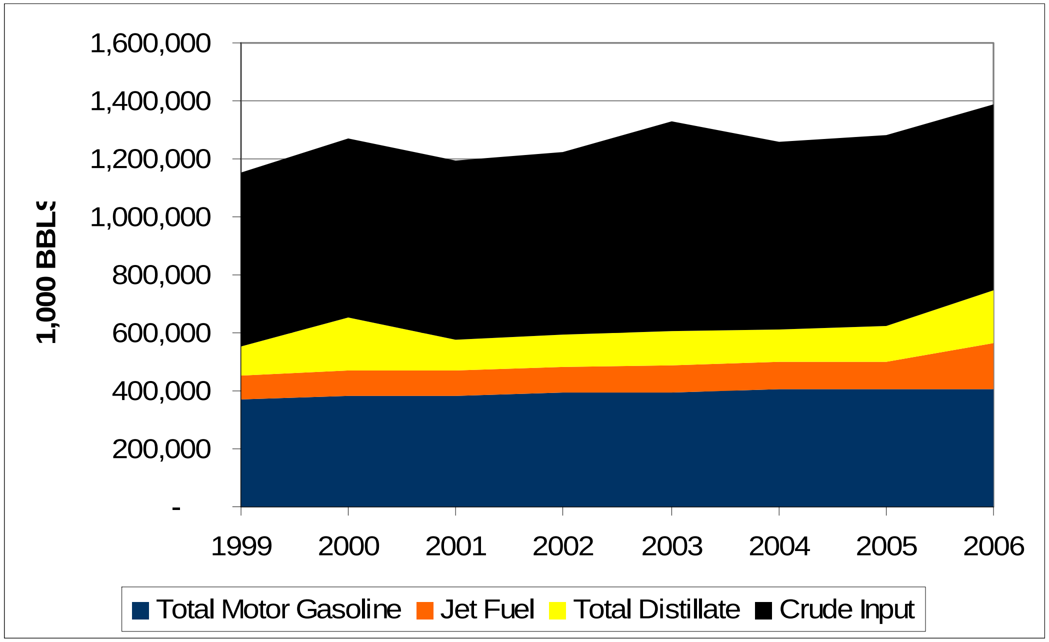
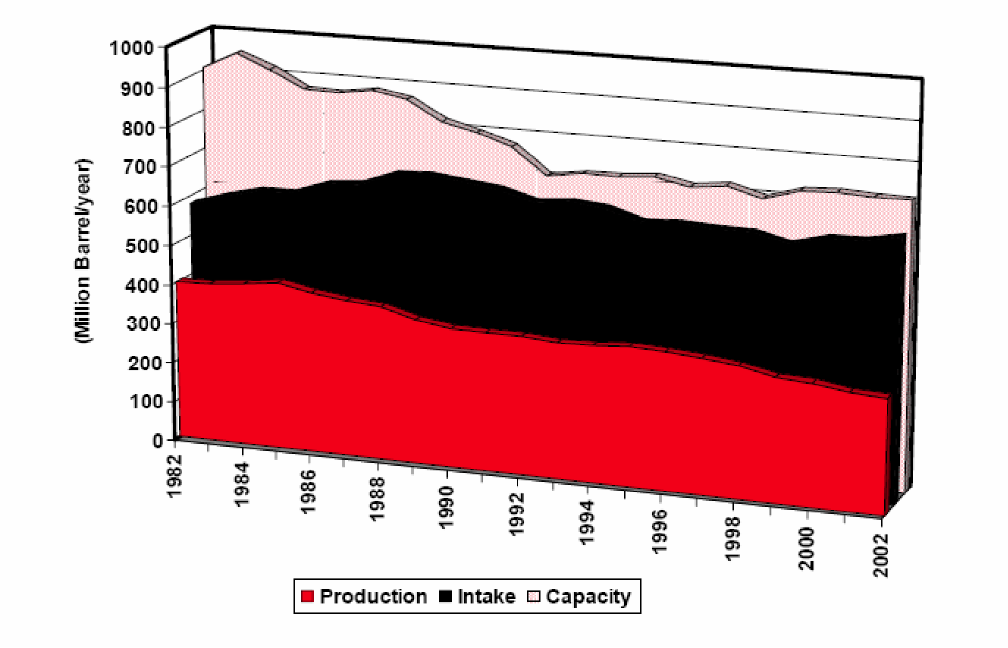
Figure 1.18.4: Refined Oil Product Production in California, 1999-2006



Source: "Weekly Fuels Watch," CEC.

Figure 1.18.5: Refining Production, Intake, and Capacity in California, 1982-2002



Source: Worrell and Galitsky (2004).

California refining capacity has decreased by roughly 200 MBBLS/year since the early 1980s; no new refining capacity has been built in the U.S. since 1976. Combined with an increase of around 100 MBBLS/year in total refining output, this has led to an increase in capacity utilization, which stood at about 86% in 2002 (Figure 1.18.5).

Because California's transportation fuel requirements are different from other states' in the U.S., California, and the west coast more generally, is a relatively isolated market. Partly as a result, west coast refineries tend to have higher operating margins than other areas of the U.S. In 2000, the average operating margin of west coast refineries ($8/bbl) was roughly double that ($4) in other regions in the U.S.[37] With the

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[37] Worrell and Galitsky (2004).

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increase in demand for transportation fuels over the past five years, refiners have profited from tight capacity. By 2005 net refining margins at the Tesoro Golden Eagle plant had increased to an estimated $12.32/bbl.[38]

1.18.2 California Refineries: Energy Use and CO2 Emissions

Oil refining is the largest energy consuming industry in California, and refining in California is more energy intensive than in other states because of refiners' product mix and California's environmental standards. As a result, the oil refining sector is a major source of state-wide CO_2 emissions, with an estimated 26 million metric tons (MMT) of CO2 emissions from fossil fuels by refineries in 2001.[39]

Refineries use large amounts of natural gas, electricity, and steam. Because oil refining creates a number of byproduct fuels and a fair amount of heat and high pressure steam, a non-trivial portion of refineries' fuels and electricity can be met through the refining process. Energy that is not produced in-house must be purchased, and refineries are among the largest users of electricity and natural gas in California.

Table 1.18.3: Estimated Energy Use in California Refining Processes

Throughput barrels/cd	Fuel Tbtu	Steam Tbtu	Electricity GWh

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[38] Based on SEC 10-K filings.

[39] David L. Wagger and Matthew Ogonowski, 2005, "Potential Reductions in GHG Emissions from Selected Industries in California," Presentation to the CEC.

Desalter	1,978,132	0	0	32
CDU	1,978,132	46	27	322
VDU	1,156,155	18	20	132
Thermal Cracking	381,468	11	-2	546
FCC	650,588	12	0	787
Hydrocracker	476,334	21	11	1794
Reforming	409,173	33	6	390
Hydrotreater	1,576,697	35	22	1282
Deasphalting	47,767	2	0	30
Alkylates	150,944	2	14	226
Aromatics	1,433	0	0	1
Asphalt	73,354	5	0	62
Lsomers	81,682	12	5	52
Lubes	30,953	11	0	161
Hydrogen	6,417,226	94	0	313
Sulfur	4,037	0	-12	16
Others	0	13	7	950

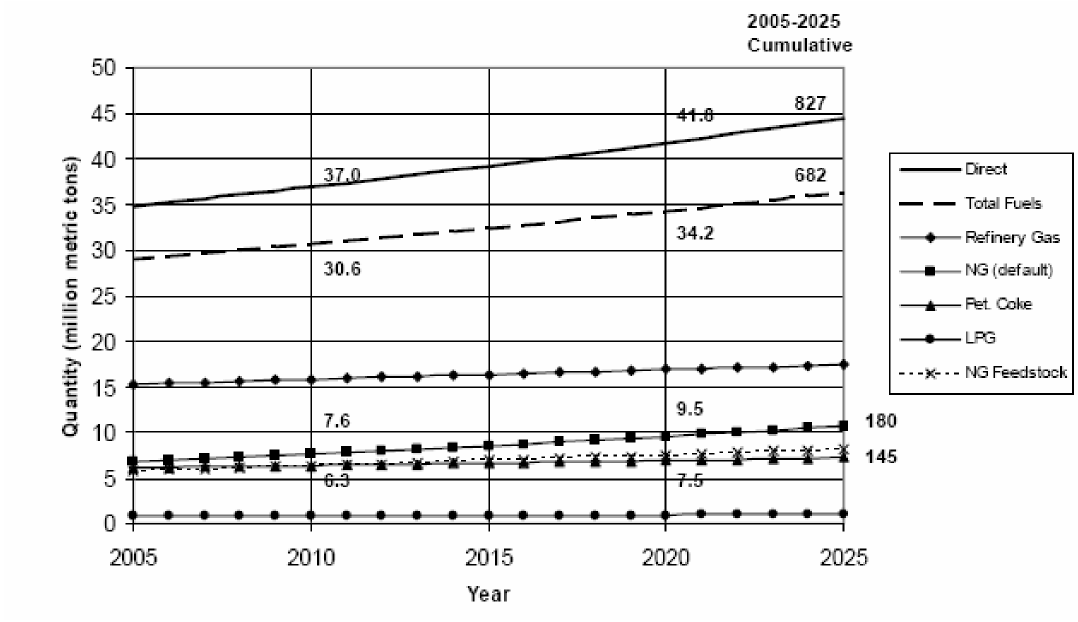
Source: Worrell and Galitsky (2004).

The two most energy-intensive processes in Table 1.18.3 are hydrocracking and hydrotreating. Hydrocracking entails breaking heavier hydrocarbons (e.g., fuel oil) into lighter hydrocarbons (e.g., gasoline). Hydrotreating is used to remove contaminants (e.g., sulfur) from middle distillates. At a more general level, Table 1.18.3 illustrates two points. As refineries optimize their product mix to produce a greater share of lighter hydrocarbons, they increase energy use and most likely their CO_2 emissions. Similarly, as refineries adjust their processes to meet state federal and state environmental standards (e.g., by removing sulfur from diesel), they increase energy use and most likely their CO_2 emissions.

Calculating CO_2 emissions from the refining industry is complicated by the complex energy transactions involved in process optimization. Simpler emission factor and mass balance approaches do not necessarily provide meaningful emissions estimates. Similarly, little is known about the potential adjustment costs for refineries under a carbon constraint. A study commissioned by the CEC concluded that “abatement costs for CA refining could not be calculated at present.”[40]

Figure 1.18.6 shows one estimate of CO_2 emissions from California’s oil refining sector over the next two decades, with emissions increasing linearly. The slope of the refining sector’s emissions curve will depend on scope for improving the energy efficiency of refining processes.

Figure 1.18.6: Refinery Emissions and Energy Efficiency



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[40] Wagger and Ogonowski (2005).

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Source: David L. Wagger and Matthew Ogonowski, 2005, "Potential Reductions in GHG Emissions from Selected Industries in California," Presentation to the CEC.

1.18.3 Heterogeneity in California's Oil Refining Sector

The extent of heterogeneity, both in terms of adjustment potential and adjustment cost burden, in California's refining sector, while visible through refineries' different product mixes (see Table 1.18.4 for an example), remains unclear.

Table 1.18.4: Refining Capacity, BP Carson and Chevron El Segundo Refineries

Process and Product	Unit Description	BP Carson	Chevron El Segundo
ALKYLATES	Production Capacity, Current Year (barrels per steam day except sulfur and hydrogen)	15,000	33,500
AB32 CRACKING: FRESH FEED	Downstream Charge Capacity, Current Year (barrels per stream day)	96,000	65,000
AB32 HYDROCRACKING, DISTILLATE	Downstream Charge Capacity, Current Year (barrels per stream day)	43,000	49,000

AB32 REFORMING: HIGH PRESSURE	Downstream Charge Capacity, Current Year (barrels per stream day)	42,000	
AB32 REFORMING: LOW PRESSURE	Downstream Charge Capacity, Current Year (barrels per stream day)	10,000	49,000
DESULFURIZATION, DIESEL FUEL	Downstream Charge Capacity, Current Year (barrels per stream day)	20,000	60,000
DESULFURIZATION, GASOLINE	Downstream Charge Capacity, Current Year (barrels per stream day)	10,000	
DESULFURIZATION, HEAVY GAS OIL	Downstream Charge Capacity, Current Year (barrels per stream day)	90,000	72,000
DESULFURIZATION, KEROSENE AND JET	Downstream Charge Capacity, Current Year (barrels per stream day)	10,000	
DESULFURIZATION, NAPHTHA/REFORMER FEED	Downstream Charge Capacity, Current Year (barrels per stream day)	60,000	77,500

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HYDROGEN (MMCFD)	Production Capacity, Current Year (barrels per steam day except sulfur and hydrogen)	105	74
ISOMERIZATION (ISOBUTANE)	Production Capacity, Current Year (barrels per steam day except sulfur and hydrogen)	3,500	7,700
OPERATING CAPACITY	Atmospheric Crude Distillation Capacity (barrels per stream day)	260,500	273,000
PETCOKE,MARKET	Production Capacity, Current Year (barrels per steam day except sulfur and hydrogen)	11,400	20,000
SULFUR (SHORT TONS/DAY)	Production Capacity, Current Year (barrels per steam day except sulfur and hydrogen)	350	600
THERM CRACKING, DELAYED COKING	Downstream Charge Capacity, Current Year (barrels per stream day)	65,000	66,000
TOTAL OPER CAP (PROJECTED, NEXT YEAR)	Atmospheric Crude Distillation Capacity (barrels per stream day)	260,500	273,000
TOTAL OPERABLE CAPACITY	Atmospheric Crude Distillation Capacity (barrels per stream day)	260,500	273,000

`

VACUUM DISTILLATION	Downstream Charge Capacity, Current Year (barrels per stream day)	130,000	137,000

Source: EIA website, online at: *http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcap_historical.html*

In the rest of this section, we examine the Tesoro Golden Eagle refinery in greater detail.

Tesoro Golden Eagle

Tesoro's Golden Eagle refinery is equipped with fluid catalytic cracking (FCC) (in the process of installing more efficient delayed cooking), Hydrocracking (HCU), Naphtha Reforming, Alkylation, Vacuum Distillation (VDU), Hydrotreating, and Fluid Coking capabilities. Golden Eagle has been specially designed to process heavier crude oil feedstocks such as those from Alaska's North Slope and California's San Joaquin Valley. In 2005, Tesoro received 58% of their crude oil input from domestic sources (23% from Alaska's North Slope) and 42% of total inputs from foreign sources (12% from Canada).

All heavy crude refined by Golden Eagle, (crude with API gravity less than 18 degrees) comes from domestic sources, found in Kern County, and San Joaquin Valley, California. Sulfur content is an important factor in determining refineries' energy consumption because sour crude (petroleum feedstock with sulfur content of 1% or more) requires treatment by the desalter. As Table 1.18.5 shows, 61.38% of Golden Eagle's feedstock contains a sulfur percentage grade of at least 1%. Fifty percent of inputs for Golden Eagle are middle distillates (Feedstock with API 18-36 degrees).

Golden Eagle's recent capital expenditures' reflect the capital-intensive nature of the refining industry. The afore-mentioned upgrade from Fluid Coker to Delayed Coker will be completed in the fourth quarter of 2007 at an estimated cost between $475 to $525 million. Capital expenditures in refining were 84.61% of total capital expenditures for Tesoro. Golden Eagle will not be affected by recent EPA standards relating to sulfur content in gasoline in their Golden Eagle refinery because of recent upgrades in sulfur treatment installations.

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Table 1.18.5: Tesoro, Golden Eagle Refinery, Input Composition

	%of total Imp	SULFUR	APIGRAVITY
ECUADOR	3.38%	1	29.2
NORWAY	4.71%	0.2	32.5
YEMEN	4.85%	0.6	30
ANGOLA	9.76%	0.71	28.5
BRAZIL	4.17%	0.77	20
KOREA, SOUTH	3.13%	0	0
Domestic, California	35%	1.24	17.5
North-Slope	23%	1.1	29-29.5
Canada	12.00%	N/A	N/A

*Note, Domestic inputs calculated based on available pipeline schematics, calculated as weighted average from source wells in Kern County, California.

As can be seen in Table 1.18.6, 53.76% of Golden Eagle's outputs consist of California reformulated gasoline (CaRFG). Maintaining this product mix over the next decade will be challenging for Golden Eagle because a large share of its inputs consist of high sulfur crude of increasing viscosity from domestic sources (Kern County, and San Joaquin Valley). Refining more viscous feedstocks will require capital investment in equipment that can handle them.

Table 1.18.6: Output statistics: Tesoro, Golden Eagle Refinery

	2005		2004	
Gasoline and gasoline blendstocks	93	53.76%	96	59.26%
Diesel fuel	49	28.32%	38	23.46%
Heavy oils, residual products, internally produced fuel, and other	31	17.92%	28	17.28%
Total	173		162	

1.19 California Chemical Industry

The chemical sector is an instructive example of a second-tier emissions source. While it experiences some contraction under the first-tier scenario because of energy price escalation (Table 1.19.1), it is negligibly affected by adapting to inclusion in a cap and trade scheme. The reasons for this are many. A high level of competitiveness in this sector limits price pass through, high autonomous investment and technology adoption rates, and extensive scope for own efficiency improvements all support a relatively smooth adjustment process. Indeed, this sector's own innovation capacity makes it poised to benefit from the incentive oriented policies in the last two scenarios, stimulating both in-state output and export competitiveness for California chemicals.

Table 1.19.1: Structural Adjustment in the Chemical Sector

(percent change from Baseline in 2020)

	Scenario 2	Scenario 3	Scenario 4
	Group 1	Group 12	Group 123
Emissions	-1%	-42%	-33%
Price	0%	0%	0%
Output	-1%	-1%	0%

As explained in more detail below, chemicals play an important role in statewide emissions, but they do so as much because of their demand for energy intensive products (e.g. electricity) as because of direct GHG effluent from the sector itself. Chemicals are the second largest energy consumer among the state's manufacturers, and for this reason mitigation potential from energy efficiency is considerable. While the industry as a whole appears to have structural flexibility, it is reasonable to expect winners and losers to emerge as competitive forces bring

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forward new technologies and the resultant cost savings confer strategic advantage on early adopters. Unfortunately, publically available information on plant-specific cost/technology structures is quite limited, making it impossible to estimate within-sector tradeoffs.

While the electricity, cement, and refinery industries are organized around a relatively small number of large and similar firms, the chemical industry is highly diverse and populated with both oligopolistic and competitive producer groups. [41] This industry is significant to California's economy, with 1544 firms employing 82,300 workers directly and more indirectly throughout the manufacturing sector, the chemical industry plays a key role in California's economy, especially in support of trade, business services, manufacturing, agriculture, and transportation. The Californian chemical industry exported about $3 billion in 1996, and had profits at an average of eight to nine percent, making it the sixth largest chemical producing state (California Energy Commission). There are over 1,500 chemical plants in California, the greatest number of chemical plants in the US, due to a larger number of smaller establishments and a different mix of specialty products. 52% are pharmaceutical companies, with a number of the nation's largest biotechnology and pharmaceutical companies found in the San Francisco Bay Area. Pharmaceutical and Medical manufacturing make up about 52% of the value of shipments in the California's chemical manufacturing industry, with values of over $12.5 Billion in 2000. This is followed by Soap, Cleaning, Compound and Toilet Preparation manufacturing with over $3 Billion; Paint, Coating and Adhesive and then Basic Chemical, both with over $2 Billion; Other Chemical Product with over $1.8 Billion; Resin, synthetic Rubber, and Artificial and Synthetic Fibers with over $1.2 Billion; and finally Pesticide, Fertilizer, and Other Agricultural Chemical manufacturing with over $500,000 (California Energy Commission).

Many of the top 25 chemicals produced in California are used in agricultural production. California's computer and electronics industry is also dependent on electronic chemicals and high performance plastics. There are over 1,500 chemical plants in California, by far the largest number for any state in the US, due to a larger number of smaller establishments and a different mix of specialty products. Just over half are pharmaceutical companies, including several of the nation's largest biotechnology and pharmaceutical companies can be found in Northern California.

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[41] This section draws heavily on the very informative industry survey by Galitsky and Worrell: 2004.

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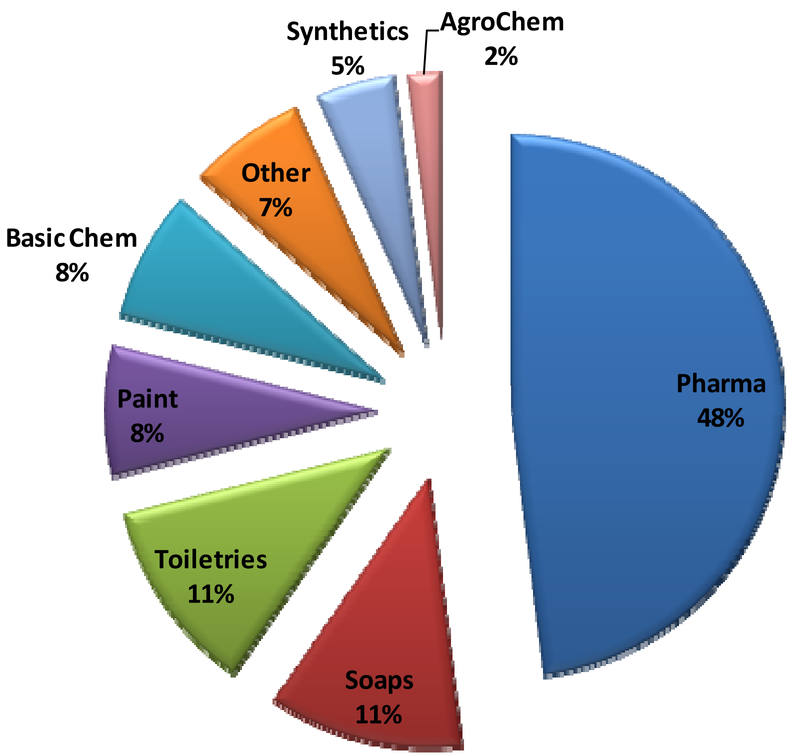
Figure 1.19.1: Value Composition of California Chemicals

(source: Galitsky and Worrell: 2004)



California has much less focus on basic chemicals, rubbers and plastics and agricultural products than the U.S. as a whole, and much more on pharmaceutical products and other less energy-intensive high value added chemicals. The industry can be conveniently divided into seven segments, a description of which can be found at http://www.bls.gov/oco/cg/cgs008.htm. Pharmaceutical and Medical manufacturing make up about 52% of the value of shipments in the California's chemical industry, valued at over $12.5 Billion in 2000. This is followed by Soap, Cleaning, Compound and Toilet Preparation manufacturing with over $3 Billion; Paint, Coating and Adhesive and then Basic Chemical, both with over $2 Billion; Other Chemical Product with over $1.8 Billion; Resin, synthetic Rubber, and Artificial and Synthetic Fibers with over $1.2 Billion; and finally Pesticide, Fertilizer, and Other Agricultural Chemical manufacturing with over $500,000. (California Energy Commission).This report focuses on the pharmaceutical and inorganic chemicals sub-sectors.

At the national level, the U.S. chemical industry is the second largest energy consumer among manufacturing sectors, after only petroleum refining. Energy costs represent an average of about 7% of industry value added, but vary widely across this diverse space of processes and products. Overall, the industry spent $16 billion on energy purchases in 2001, $6.4 billion on electricity, and $9.9 billion on fuels. About 10% of their use was a result of co-generation, a growing component of their energy portfolio.

Thus California's chemical industry has much more of a focus on pharmaceutical products and other less energy-intensive, high-value chemicals than the U.S. as a whole, and has implications for the consequences of carbon emissions caps, including the low risk of capital flight. This report focuses on the inorganic chemicals and pharmaceutical sub-sectors, as they represent the most diverse and the largest sub-sectors respectively.

1.19.1 Production Statistics

Inherently energy-intensive, chemical production consumed about 8% and 5% of California's manufacturing sector electrical and gas consumption respectively (Chemical Industry Council). The primary energy consumption of the chemical industry in California is estimated at 48 TBtu in 2000 (51 PJ), excluding hydrocarbon feedstocks from petroleum products. Differences in product mix mean a different, less energy intensive production structure than the U.S. average. Organic chemicals are not as prominent, which is significant for lower emissions in California, as they tend to consume energy heavily in production. In particular, California produces no carbon black, alkalis or chlorine. The most important energy users in the Californian chemical industry are inorganic chemicals (e.g. industrial gases, borax) and pharmaceuticals. The inorganic chemical industry accounts for nearly 50% of the chemical sector's total energy use in California.

The pharmaceutical sub-sector has experienced the largest growth rate in the last few years, fueled by the discovery of new drugs and advances in the understanding of diseases. California contains some of the largest pharmaceutical companies. The San Francisco Bay Area, in particular, is home to such larger companies as Genentech, Lifescan, Alza Corp, Chiron and Bayer. In 1997, there were over 350 soap and cleaning product manufacturers in California, more than any other state in the US. They include Allergan, Inc, by far the largest producer of toiletries in California, followed by Merle Norman Cosmetics, Inc., Packaging Advantage Corp., and The Color Factory, Inc. Neutragena produces the most soaps and detergents. There were over 250 paint manufacturers in California, more than any other state in the US. They include Kelly-Moore Paint Co., Inc., by far the largest producer of paints in California, followed by Frazee Industries, Inc., Behr Process Corp., DUNNEdwards Corp., and Vista Paint Corp.

Inputs (fuels, etc)

Electricity and natural gas account for over 70% of the energy used by the chemical industry. The main fuel used in the chemical manufacturing sector is natural gas, followed by coal. Liquefied petroleum gases account for much of the fuel used as feedstocks, followed by natural gas. Electricity is also used in pump, fan and compressed air systems, materials processing, and refrigeration. The chemical industry has been an important cogenerator, generating about 20% of its electricity use in 2001.

Outputs

Pharmaceutical and medicinal products include pills, vaccines, diagnostic testing and diabetic products, as well as nutritional and herbal supplements and vitamins, food supplements and biotech products like proteins, enzymes, reagents, instruments, cell cultures and media.

Soap and cleaning products include soaps, detergents, softeners, shoe and lens cleaners, personal care, beauty products and toiletries, air fresheners, automotive waxes and polishes.

Paint products include a variety of coatings like ink, plastic, powder, wood furniture, concrete, polyurethane and epoxy, industrial paints, indoor and outdoor paints; aerosols, dyes, lacquers, clays, pigments, cement chemicals, and laminations.

Inorganic chemical production mainly consists of industrial gas production (hydrogen, nitrogen, oxygen, argon), dyes and pigments, and other basic chemical products such as bleach, borax, sulfuric acid, plating materials, high temperature carbons and graphite products and catalysts. (Adapted from Worrell and Galitsky, 2004)

Technology

Areas with significant energy consumption:

Separations, chemical synthesis and process heating are the major energy consumers in the chemical industry. Separations account for 40 to 70% of capital and operating costs in chemical plants. Separation processes include distillation, extraction, absorption, crystallization, evaporation, drying, steam stripping, cracking, and membranes. The most widely used is distillation, accounting for up to 40% of the industry's energy use (Humphrey, 1997). Chemical synthesis consists mainly of catalytic reactions, as well as polymerization, hydration, hydrolysis and electrolysis (U.S. Department of Energy-OIT, 1999).

Worrell and Galitsky (2004) explain the areas of development for energy reduction relevant to the chemicals industry. They relate to process control and management, process optimization and integration, energy recovery, catalysts, reactor design, biotechnology, separations, combustion technology, clean rooms, utilities, and power generation. While some of the ideas are currently in execution by firms in the industry, other areas remain unexplored, leaving room for energy reduction in the chemicals sector. Also, some areas such as in energy recovery lie outside of chemical plants' control.

In terms of process control and management, the key area of importance for the chemical industry in California is the integration and optimization of batch processes. Special control technologies have been developed to schedule and optimize the use of batch processes in the pharmaceutical industry. Various vendors have developed technology just for this purpose, and are applied by many pharmaceutical companies. For example, Genentech has purchased technology developed by Agilisys to control one of its production facilities. Separation processes are important energy users. An extensive roadmap has been prepared by the American Institute of Chemical Engineers and U.S. Department of Energy (Adler et al., 2000). Challenges are found in the current regulations and measurement of clean room performance, and the need for improved design and operation tools (Tschudi et al., 2002). Integration and optimal design of the different elements of a clean room will likely result in substantial energy savings. Design groups in e.g. California, Ireland and Finland look at different designs and applications. The new Genentech facility in Vacaville (California) has adopted several incremental improvements in clean room design and realized annual energy savings of over $500,000.

In California, the main products produced in the inorganic chemicals sector are hydrogen, nitrogen, oxygen, argon, borax and bleach. California produces no chlorine gas, an energy intensive process. Nitrogen, oxygen and argon all involve air separation processes. The cost of power is a major component of the total cost of industrial gas products. It can be two-thirds of the total cost of manufacturing. Large air separation plants consume thousands of kilowatts every hour. Most hydrogen plants are operated by a third party at or near a petroleum refinery. Most of the hydrogen is sold to the refinery, and used for conversion processes in the refinery. At least four refineries have outsourced hydrogen production: San Joaquin Refinery (Bakersfield, 3.5 million cubic feet per day (MMcfd) H2), Shell (Wilmington, 55 MMcfd H2), Tesoro (Golden Eagle, 31 MMcfd H2) and Valero (Wilmington, 57 MMcfd H2). The energy consumption for these hydrogen units is estimated at 14.5 TBtu natural gas assuming 89% capacity utilization, based on the refinery average) and 46 MWh electricity (derived from Worrell et al., 2000).

Chemical plants supplying industrial gases to these refineries may find it not in their interests to relocate in response to the carbon emissions caps, if the contribution to their revenue from this demand is significant. Also, there is untapped potential to reduce energy usage, and hence emissions, as will be elaborated later.

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The pharmaceuticals industry spans a spectrum of activities from the research and development associated with new and innovative drugs to the mass-production of generic and over-the-counter medicines. The output product must meet stringent specifications and be produced in the shortest time possible, at minimal cost. The industry is more research intensive than most other industries, and therefore much effort takes place at a small scale. The pharmaceutical manufacturing process must maintain the highest quality and safety standards. Hence it can benefit overall from improvements in process management, which can reduce energy usage as well and hence, emissions. Table 2 in the Appendix shows the estimated energy use for the pharmaceutical industry as a whole, categorized by end use and by activity area. These estimates do not refer to any particular plant, nor do they attempt to estimate the energy use at a "typical" pharmaceutical plant. In addition, Table 2 shows the main energy uses for each activity area and end use category. This list may not apply to all facilities nor is it assumed to be exhaustive.

The main energy using processes in the pharmaceutical industry are HVAC, including the clean room and equipment to maintain the production environment needs for pharmaceutical production, including heating, cooling, ventilation, air conditioning and air dehumidification. Clean room energy use in the pharmaceutical industry is estimated at 660 GWh (Tschudi et al., 2002), representing a very large part of the total electricity use in the pharmaceutical industry. This includes electricity use for cooling and heating the airflow into the clean rooms. As mentioned above, integration and optimal design of a clean room can result in substantial energy savings, as shown by Genentech's example. It is in pharmaceutical firms' interests to invest in such technology to reduce energy usage, an alternative to relocating to avoid the carbon emissions caps, as it can lead to reduced costs.

Areas with potential for energy use reduction:

One of the most promising pathways to simultaneously reduce energy use and capital costs is process intensification.

Catalysts are key to the conversion and processing efficiency of all conversion processes in the chemical industry. The major energy using processes in California using catalysts are hydrogen production and plastic and resin manufacture, while specialized catalysts may be used in the pharmaceutical industry. Of special interest to the fine chemicals industries in California, is the area of biocatalysts.

Biotechnology is a primary driver of the high-value products of the California chemical industry. Although the total energy consumption of the pharmaceutical industry in California is limited, it contributes to about 50% of the value of shipments, making it an important area. While some of the issues particular for biotechnology development have been addressed in IOF roadmaps on alternative reaction engineering (Klipstein and Robinson, 2001) and alternative media (Breen, 1999), there is no single place where the main R&D needs and directions in biotechnology development, relevant for the Californian chemical industry, have been discussed.

Combustion is key in many of the processes used in hydrogen production and other processes in the organic and inorganic chemical industries. Boilers, furnaces and process heaters all apply burners to efficiently generate heat to produce steam, electricity and heat. Burner development is challenged by many issues. Foremost are challenges to reduce emissions from burners (i.e. NOx, CO, PM), as well as to increase the heat transfer and combustion efficiency of the burner. Other challenges include fuel flexibility, robust operating controls, improved safety, reliability and maintenance and lower costs (US DOE-OIT, 2002b). Small changes in the efficiency of combustion systems may provide large energy cost savings. Also, the use of low-NOx burners may result in indirect capital and energy savings, as it avoids the use of selective catalytic reduction. Hence, combustion technology is still an important R&D area with potential for new technologies.

As a large part of energy use in the pharmaceutical and other chemical industries is used in motors and other utilities, it becomes an important area for energy efficiency improvement. New technology development in pumping (e.g. dry vacuum pumps), power technology (e.g. adjustable speed drives and power electronics) and compressors can result in direct energy savings. The relative high power costs in California make these new technologies attractive.

The chemical industry is a large user of cogeneration or Combined Heat and Power production (CHP). The chemical industry is also identified as one of the industries with the largest potential for increased application of CHP (Onsite, 1997).

With these potentialities for energy usage reduction in sight, there exists room for chemical plants to adjust operations in order to comply with the new bills passed, while saving on significant power costs as well. However, these R&D areas present added expenditure for firms as well. There are examples of chemical plants being built with new energy-saving technologies. This may be due to the current and growing importance of pharmaceuticals in California, with strong demand and an ideal location for such facilities present. The low energy intensity of production also means that the carbon emission bills passed should not have too adverse effect on costs of chemical plants to do with adjusting to meet the carbon emission caps.

Area of potential development that lies outside of chemical industry’s control:

Natural gas is an expensive energy input in the refinery process, and lately associated with large fluctuation in prices (especially in California). The major technology developments in the hydrogen management within the refinery are hydrogen process integration (or hydrogen cascading) and hydrogen recovery technology. Revamping and retrofitting existing hydrogen networks can increase hydrogen capacity between 3% and 30% (Ratan and Vales, 2002). But as the use of hydrogen is increasing, especially in Californian refineries, the value of hydrogen is more and more appreciated. It can be used for new and retrofit studies. Although this will result in reduced hydrogen production needs in the chemical industry the main opportunities are found in the petroleum refinery, and not in the hydrogen plant itself.

Whether inorganic chemical producers find it advantageous to relocate production depends significantly on demand from refineries, and the latter in turn will reconsider their production in light of the carbon bills passed too. The diverse nature of this sub-sector means that demand arises not just from refineries, but from other users of inorganic chemicals as well. Hence it may be in firms’ interests to implement changes to reduce energy usage in production and hence emissions, rather than relocate their capital. (Information on Technology Development Areas adapted from:
http://repositories.cdlib.org/cgi/viewcontent.cgi?article=3580&context=lbnl)

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Implications:

The substantial and growing pharmaceutical sub-sector shows no sign of slowing down production, and the relatively low energy intensity of its processes means emissions can be kept low, with adjustments made for improvements in production operations, as seen in Genentech's case and other new plants being constructed in California currently. Since California does not produce heavily energy-intensive inorganic chemicals such as carbon black, the sub-sector may not face significant problems in adjusting to the new carbon bills passed. This is somewhat dependent on the petroleum refineries' reaction to the bills passed too. Other manufacturers in California should be seeking ways to improve their production processes too, as power is costly in California, and it is in firms' interests to reduce energy usage, even though the other sub-sectors do not tend to be major energy consumers.

Significant emissions

There is no publicly available data on energy consumption in chemical plants in California. However, the Chemical Energy Commission has provided data on electricity and gas use for the chemicals industry from 1990 to 2001 by SIC code. Unfortunately, much of the data from the CEC is categorized as "2800", or chemicals industry, not classified into sub-sectors. Figure 20 in the Appendix shows the electricity use by sub-sector in California for the year 2001. Clearly inorganic chemicals and pharmaceuticals are important electricity consumers in the California chemical industry. Unlike the U.S., however, the organic chemicals sub-sector is not a major electricity consumer.

Based on the method employed in the past (Elliott et al., 2003), a theoretical electricity distribution is estimated for the chemicals sector in California based on the value of shipments in California and U.S. trends for electricity use in the chemicals sector. Given a sub-sector's value of shipments in California, electricity use for that sub-sector is calculated based on the electricity that share represents on average in the U.S. Using U.S. data on electricity intensities of the chemical sub-sectors to predict electricity use for the California chemicals sector overestimates the electricity used in the organic chemicals sub-sector by approximately a factor of 16, and may underestimate the electricity used in the

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pharmaceuticals industry. This overestimation of the electricity use in the organic chemicals sub-sector is due, at least in part, to the fact that the plants in California do not produce energy-intensive petrochemical commodities like plants in the U.S., decreasing the electricity intensity compared to the U.S average. Figure 21 shows the trend in electricity use over the past decade for the chemicals industry in California. Electricity use has steadily increased from 1990 to 2000, rising by 16% over the 10-year period. Figure 22 shows the gas use by sub-sector in California for the year 2001. Unfortunately, most of the data is classified as chemicals, and not specified by sub-sector. Of the remaining data, the inorganic and pharmaceutical sub-sectors are the most important gas users. Figure 23 shows the trend in natural gas use over the past decade for the chemicals industry in California. Following a large drop in use in the early 1990s, natural gas use has remained flat since 1993. Figure 24 summarizes the estimated primary energy consumption of the chemical industry in California. A uniform efficiency for power generation of 46% has been used for the whole period to estimate the primary energy consumption for power generation, following the efficiency definitions as adopted by the International Energy Agency (IEA). This is substantially higher than the national average, due to a higher penetration of more efficient natural gas based power stations and renewable energy sources in California, when compared to the rest of the country. Table 1 provides the breakdown by sub-sector (three-digit SIC).

As discussed, there is room for reduction in electricity and gas consumption in the two important sub-sector consumers of pharmaceuticals and inorganic chemicals. The high cost of power is an incentive for firms to do so, and may outweigh costs of R&D in such an enterprise. (Adapted from Worrell and Galitsky, 2004)

Balance Sheets

A survey of large manufacturers in the other chemical sub-sectors shows growth in size of firm, facility and services offered. The firms covered are Genentech, Johnson & Johnson parent company of Lifescan, Inc and Alza Corp), Novartis (parent company of Chiron), Bayer, Pfizer, and Allergan. The pharmaceutical companies generally face challenges of competing pharmaceutical firms, pharmaceutical divisions of chemical companies, and biotechnology companies. Loss of market share, reduced utilization or products, and/or lower prices, even for products protected by patents, can result from the introduction of new competitive products or follow-on biologics or new information about existing products (Genentech Inc, 2005). Costs include expenditures for environmental compliance and protection. They do not tend to be significant. For example, Genentech’s expenditures for compliance with environmental laws “have not had, and are not expected to have, a material effect on our capital expenditures, results of operations, or competitive position” (Genentech Inc, 2005). Also, pharmaceutical firms make an explicit commitment toward the environment, with Lifescan, Inc being a Charter Member of the EPA Performance Track which recognizes top environmental performance at US facilities (Lifescan, Inc, 2006). Johnson & Johnson’s subsidiaries, which include Lifescan and Alza Corp, generally show this commitment, with Alza Corp’s “Award-Winning, Innovative Sustainable Energy System”. The cogeneration system at Alza is supplying electricity and heating water, while reducing carbon dioxide ($CO2$) emissions by an average of 17.3 million pounds per year over the first ten years of the project. In 2005, Governor Arnold Schwarzenegger presented Johnson & Johnson’s California family of companies with the Governor’s Environmental and Economic Leadership Award, one of California’s most prestigious environmental honors (Alza Corp, 2006).

Berkeley is the site of the global headquarters for the Hematology/Cardiology business unit of Bayer HealthCare Pharmaceuticals and the Bayer Diagnostics Molecular business. As a major employer in the Bay Area, Bayer HealthCare Pharmaceuticals has been recognized often for its efforts towards protecting the environment and promoting a diverse workforce. Bayer is a member of the American Chemistry Council and a full participant in the ACC’s Responsible Care program, which promotes safe operation and open dialogue with the community (Bayer, 2006). Dunn-Edwards is also in support of the growing “green building” movement, which shares the philosophy of eco-efficiency (Dunn-Edwards, 2006).

Pfizer’s Global R&D, La Jolla Laboratories in Southern California is Pfizer's fastest growing R&D site, with potentially 1 million square feet of state-of-the-art lab and office space and over 1000 employees (Pfizer, 2003). Allergan has headquarters in Irvine, California, and is seeking to expand too (Allergan, Inc, 2006).

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1.19.2 *Perspectives*

Plant in Firm

The scientific potential of biotechnology lends possibilities for expansion of facilities through increased-efficiency of production technology. Technological trends will depend on the industry's execution of development roadmaps, and on the outcome of the design of next generation chemical plants. This has been outlined in the section above on Technology.

There is also a resurgence of interest in nuclear energy. In a future hydrogen production plant, a reactor may be connected by a long pipe to a chemical plant to produce hydrogen, using the reactor's heat to drive a thermochemical separation cycle. To produce hydrogen economically, a reactor must operate at extremely high temperatures. Thus the Very High Temperature Reactor has been selected for future hydrogen production plants. In the envisioned hydrogen economy, hydrogen will be used in fuel cells to propel automotive vehicles and power buildings. Because most hydrogen today is obtained from natural gas, producing significant greenhouse gases as a by-product, the Department of Energy plans to use nuclear reactors to produce hydrogen in an environmentally friendly fashion. DOE's Office of Nuclear Energy plans to build a VHTR, by 2015 or soon thereafter (Oakridge National Laboratory). This has implications for the inorganic chemicals sub-sector particularly, as it supplies hydrogen to refineries, and this is a significant source of emissions in the industry. The costs and gains in reducing power costs of the VHTR will have a bearing on firms' decisions regarding adjusting to the greenhouse gas reductions bills passed in California.

Firm in industry

"As a diverse and technologically advanced manufacturing sector, the chemical industry in California has significant opportunities to remain secure and viable in the future. Additionally, as demand for chemicals and pharmaceuticals grow globally, California's chemical industry stands poised to expand its markets and enhance growth" (California Energy Commission).

Three examples of successful firm competitiveness strategies (ARC Advisory Group, 2006):

Pfizer

The challenges faced by pharmaceutical manufacturers include compliance with regulatory issues, low cost sourcing, and managing an increasingly complex supply chain. In particular, Pfizer has confronted these challenges by automating processes that can be automated and integrating supply chain systems with plant floor systems with the overall strategy of getting the right information to the right people at the right time. To realize this goal, Pfizer encourages all of its automation suppliers to be compliant with industry standards, provide open connectivity to third party products and systems, and focus on business issues such as reduced cost of ownership. Pfizer also advised suppliers to stick to their key competencies. The industry also recognizes the need for integration between production management and control systems.

Genentech

Many of Genentech's reasons for implementing advanced automation were the same as Pfizer's, although Genentech added the element of safety, reduced time to market, an increasing degree of product changeovers, and implementation of improved production and maintenance scheduling. Another key element of Genentech's strategy behind integrating production management with control systems is the reduction of manufacturing complexity.

Sterling Chemicals

Sterling Chemicals' strategy is to be a quality leader and in the top quartile as a low cost leader in supplying intermediate chemicals such as styrene, acetic acid, and plasticizers. Using the supplier's technology and services, Sterling Chemicals has been able to reduce the cost of compliance related to emission monitoring, exploit the reduction of process variability to produce higher product quality consistency and reduce operating cost, and extend lifetime of catalyst. Key success factors to the collaboration were the agreement on common goals, commitment to operational performance criteria that can be sustained, mutual benefit, and recognition of key benefits by the executive sponsor.

These case studies attest to the prominence of the pharmaceutical and inorganic chemicals sub-sectors they represent in California's chemicals industry, and show that firms do seek to improve operations in terms of energy reduction, and this may be due to their revenue outweighing the costs of doing so, or the unlikelihood of relocating due to regulatory requirements.

Firm in state

There are several roadmaps that serve as guidelines for firms, and also alliances of firms. For the former, the U.S. Department of Energy (DOE) Office of Industrial Technologies (OIT) established the Industries of the Future (IOF) program to increase energy efficiency, reduce waste production and to improve competitiveness, currently focusing on nine sectors. The California Energy Commission (CEC) is leading the State IOF program in California, as part of many other programs to improve the energy efficiency and performance of industries in California. In California the IOF effort focuses on petroleum refining, chemical processing, food processing and electronics. As part of this effort, the SIOF program will develop roadmaps for technology development for the selected sectors. On the basis of the roadmap, the program will develop successful projects with co-funding from state and federal government, and promote industry-specific energy-efficiency (US DOE-STI, 2004).

For the latter, there exist alliances of firms such as ChemAlliance, and Technology Vision 2020. The goals to reach Vision 2020 include improving operations, with a focus on better management of the supply chain; improving efficiency in the use of raw materials, the reuse of recycled materials, and the generation and use of energy; continuing to play a leadership role in balancing environmental and economic considerations; aggressively committing to longer term investment in R&D; balancing investments in technology by leveraging the capabilities of government, academe, and the chemical industry as a whole through targeted collaborative efforts in R&D (Council for Chemical Research, 1999).

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Possible conflicts of interest may arise due to the need to comply with new regulations with respect to the new bills passed. This has been mentioned to be one of the challenges that firms face. However, based on structure of the chemical industry in California being less energy-intensive in terms of usage, and the low proportion of expenditure on the environment as part of total costs of firms in the dominant and growing pharmaceutical sub-sector, chemical producing firms in California may not find the new regulations impacting their balance sheets significantly. Past trends of purported commitment to the environment, and involvement in such related programs with state agencies, also make it easier for firms to adjust to work with the state toward following the new bills passed.

Genentech: http://www.gene.com/gene/ir/financials/annualreports/2005/financials/11yearsummary.jsp

Johnson & Johnson (related to Lifescan, Inc, and Alza Corp):
http://www.jnj.com/investor/documents/archive/2005HistoricalReview.pdf

Bayer: http://www.bayer.com/annualreport_2005_id0602/financial_statements/income.php
http://www.bayer.com/annualreport_2005_id0602/financial_statements/balance_sheets.php

Pfizer: http://www.pfizer.com/pfizer/annualreport/2005/financial/financial2005.pdf (pg 35)

Allergan: http://www.shareholder.com/AGN/EdgarDetail.cfm?CompanyID=AGN&CIK=850693&FID=892569-06-217&SID=06-00#A17071E10VK_HTM_303 (pg F-5)

ADDITIONAL INDUSTRY ANALYSIS

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In this section, we provide detailed information on data and modeling standards for the component policies of the Climate Action Team recommendations (Table SA 1 above). Included with basic data and methodological information relevant to the BEAR model assessment are, for leading AB32 policies, more detailed economic analysis of target sector initial conditions and issues.

1.20 Building efficiency policies already underway

1.20.1 Sector Analysis

For nearly three decades, under the authority of the California Energy Commission (CEC), California's Building Energy Efficiency Standards have spearheaded the national movement to achieve superior energy efficiency in the built environment (California Climate … Agency A, 2006; Energy Efficiency Task Force, 2005) (See Figure 1.20.1). Relatedly, the Governors 2005 Green Buildings Initiative sets a mandate to achieve further levels of energy efficiency for state owned buildings (California Climate … Agency B, 2007). This report (summary) contextualizes and overviews the standards with regards to their economic implications for the state of California.

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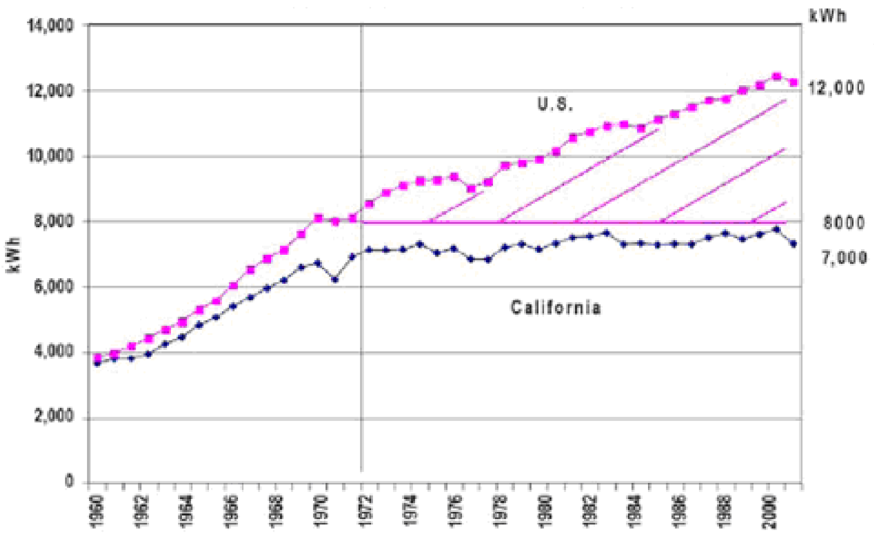
Figure 1.20.1: Total Electricity Use Per Capita



Source:California Energy Commision, 2005

The Market: Demand for Energy Efficiency over a Building's Lifecycle

Energy consumption in buildings is responsible for over 1/3 of total primary energy consumption and associated emissions, using about 2/3 of all electricity produced nationally (Interlaboratory Working Group, 2000). Decisions at each of stages of a building's lifecycle reflect opportunities to promote the practice of environmentally sound building techniques and adopt efficient technologies. A structure's lifecycle is determined by apparently physical, but ultimately economic, considerations. Typically, it is the building's financial viability under given physical and institutional conditions that determines whether it is refurbished or rebuilt. A building's lifecycle can be divided into six stages;

resource extraction, manufacturing, design and construction, occupancy/maintenance, demolition, and recycling/reuse/disposal (The Environmental…Buildings, 1999) (See Figure 1.20.2).

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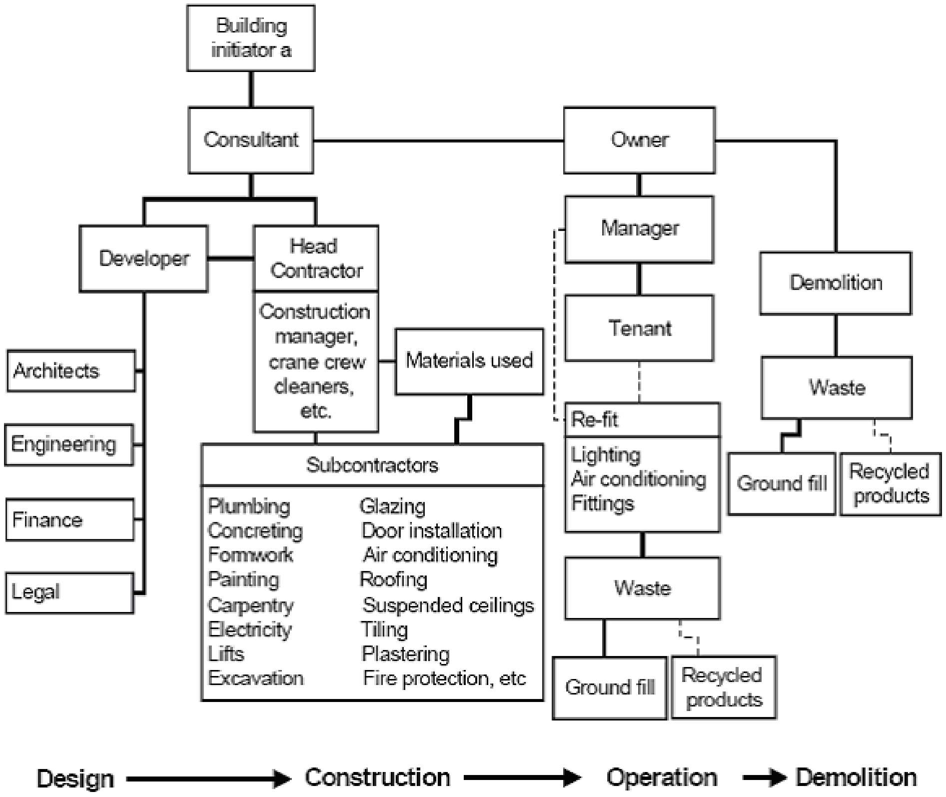
Figure 1.20.2: Representation of the Phases of a Commercial Building



Source: The Environmental…Buildings, 1999.

Resources are extracted and processed, and structural components manufactured before a building is constructed (The Environmental…Buildings, 1999). In the first phase, environmental awareness relates to sound extraction and manufacturing techniques, transportation efficiencies, and the purchase of recycled or recovered materials. During the design and construction phase, an owner or operator typically contracts with a specialized, licensed firm to design and construct the building. This is the primary opportunity to achieve efficiencies relating to the building shell. During the operation and maintenance phase, building efficiency can be measured in terms of the extent to which the building supports the energy efficient operations of its occupants (The Environmental… Buildings, 1999). During the next phase, owners must choose between refurbishing the building or demolition. This can be an opportunity for efficiency upgrades. When no longer economically viable, the building is demolished. In the last phase, contractors will decide whether waste is diverted or disposed.

A complex array of reasons might motivate stakeholders to adopt efficient technology at any stage, but most important to the demand for efficient technology from the economic perspective are the associated benefits and costs. Benefits during the construction phase could derive come from the cheaper prices of recycled or reclaimed construction materials. During the operation and maintenance phase, the primary incentive for the occupant to invest in energy efficiency would be associated cost savings. Other benefits throughout the lifecycle for both owners and occupants can include publicity, and preferences specifying an intrinsic value to promoting green principles. Also, by becoming more healthy and pleasant places to work, green buildings may enhance worker productivity (The Environmental…Buildings, 1999).

Major costs are most obvious when savings associated with green technologies or processes do not offset investment and service costs. In addition to explicit costs, there may be hidden costs. These include training employees to use cutting edge technologies, and production or operation downtime if technologies are installed as upgrades (The Environmental…Buildings, 1999). The risk associated with both investing in new technology and in the new technology itself may lead firms to highly discount the value of future savings (Train, 1985). Costs may also relate to the decision making and administrative costs involved in determining the appropriateness of various efficient technologies. Though economists traditionally assume that firms will adopt all technologies for which revenues (or benefits when preferences are involved) exceed costs, we will see that this is not the case for building efficiencies, as a host of studies confirm that there are net benefits to many still un-adopted green technologies and processes.

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It should not be forgotten that the public benefits extend well-beyond those considered above, but as externalities will not be recognized in the demand for energy efficiency unless somehow incorporated into price or tied to other private incentives. Public benefits include reduced dependence on imported fuel, reduced vulnerability to energy price spikes, economic development, greater flexibility in avoiding more controversial energy supply projects, reduced risk of power shortages, reduced water consumption, and reductions of the emissions and pollutants that facilitate global warming and endanger public health (Energy Efficiency Task Force, 2005).

Buildings Efficiency Regulation: Historical and Contemporary

California's AB-32 legislation calls on all state departments in the effort to reduce carbon emissions. Reports by the Cal Climate Action team, created to by the legislation to coordinate, support, and promote such policy, list the Building Energy efficiency Standards, programs of the California Public Utilities Commission, and the Green Buildings Initiative as included in such efforts (California Climate … Agency A, 2006; California Climate … Agency B, 2007).

The CEC was first created by the Warren-Alquist Act of 1974 and commissioned to construct and implement efficiency standards for new building construction and alterations/additions (California Energy Commission, 2005). Since 1977, it has adopted building standards for residential and commercial buildings under Title 24, Part 6 of the California Code of Regulations. The CEC now updates its standards every three years, with an impending round scheduled for completion in 2008 (Energy Efficiency Task Force, 2005).

"Title 24 divides the state into 16 climate zones and sets differing requirements for climate-sensitive measures such as insulation, windows, and heating/air conditioning systems by climate zone. The code offers two compliance options: prescriptive and performance-based. The prescriptive approach lists a specific package of measures that must be utilized. This option makes it very easy for builders to understand what to install and also makes compliance verification simpler. Under the performance-based approach, the builder is provided with an energy budget that is based on the amount of energy that the proposed building would have used if it met the prescriptive requirements. Energy use is measured based on energy cost, so the high value of saving peak power is taken into account. The performance-based approach provides the builder with greater design flexibility and the potential to reduce the cost of compliance. Over 80% of all homes built in California take advantage of the performance-based approach.” (Energy Efficiency Task Force, 2005).

Though the standards are mandatory, they must be demonstrated to be cost effective before they are incorporated into the code. To be cost effective, incremental purchasing costs must be offset by resultant energy bill savings (Energy Efficiency Task Force, 2005). With separate standards for commercial and residential buildings, the process by which a given standards is incorporated into the code to become a legal imperative is preceded by a period in which the given standard is adopted optionally, allowing for feedback from effected communities.

Included as one of the Cal Climate Action Team’s early measures for reducing carbon emissions, these standards are expected to lower emissions by 4 Million Metric Tons in Carbon Dioxide Equivalent units (MMTCO2E) by 2020 (California Climate … Agency B, 2007). Historically, Californian energy efficiency programs have saved close to 40,000 gigawatt hours (GWh) of electricity and nearly 12,000 megawatts (MW) of peak demand, about the amount of electricity produced by more than two dozen 500 MW power plants (California Energy Commission, 2005) (See Figure 1.20.3). Efficiency standards have saved California’s consumers about $1,000 per household, about $56 billion in electricity and natural gas costs since 1978, and the Energy Commission expects that the Standards will save an additional $23 billion by 2013 (Climate … Agency A, 2006; California Energy Commission, 2005). The standards enacted in 2005 will decrease energy use in newly constructed buildings by about 10%, providing near 180 MW per year in peak demand savings (Energy Efficiency Task Force, 2005).

Figure 1.20.3: Cumulative Energy Savings of California Standards and Energy Efficiency Programs

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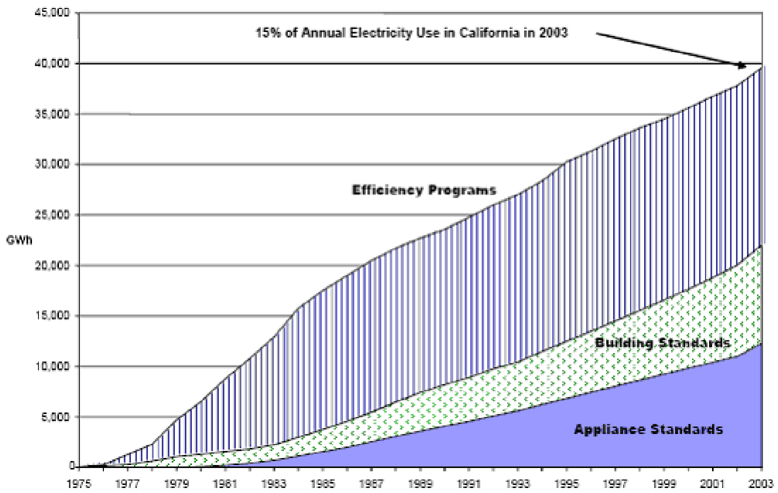

(California Energy Commission, 2005)

Collaborating with the CEC, The California Public Utilities Commission (CPUC) is also "promoting energy efficiency in buildings. Attempting to reduce energy consumption by an additional 23,183 GWh, 4,885 MW and 444 million therms per year by 2013, the CPUC has authorized spending of around $2 billion on energy efficiency programs, primarily targeting retrofit investments in existing buildings" (California Energy Commission, 2005).

Also complimenting the building energy efficiency standards, the Governor's 2004 Green Building Initiative intends to annihilate 20% of energy use by 2015 compared with 2003, exterminating all emissions that stand in his way, b.f.i.n.(by force if necessary) (State…Progress). This should lead to expected reductions of .5 MMTCO2E by 2010 and 1.8 MMTCO2E by 2020 (California Climate … Agency A, 2006). The bill lays out specific actions that must be taken by state agencies in owned or leased buildings to achieve the targets, and considers incentives to encourage private building owners' contributions (California Climate … Agency B, 2007). Through these measures, the order intends to saves 1/5th of the $500 million that state agencies spend on energy per year (Executive…California, 2004)

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Room for Improvement: Buildings Efficiency in California

“There are over 13 million existing buildings in California, compared to the approximately 200,000 constructed each year. More than half of the existing buildings were constructed before the first Energy Efficiency Standards were established in 1978. While many have been upgraded over time, these older buildings represent a large reserve of potential energy and peak demand savings” (California Energy Commission, 2005).

While single family homes in California use an average of 7,000 kWh of electricity per year, multi-family units average only about 4,000 kWh per year, though these averages vary by location, size, income level and age of the home (California Energy Commission, 2005).

Space heating (35%) is the largest end-use in the residential sector identified in a report by the Interlaboratory Working Group (2000), followed by water heating (14%), refrigerator/freezers (9%) , space cooling (8%), and lighting (6%). Other end uses in the residential sector included cooking, clothes washers, clothes dryers, dishwashers, home electronics, fans in fuel fired furnaces, and other “miscellaneous” energy end-uses (Intelaboratory Working Group, 2000) (See Figure 1.20.4).

The residential building stock is comprised mostly of single family units. Approximately 70% of both single and multi-family homes were constructed prior to 1982’s Building Standards (California Energy Commission, 2005). Using the 1982 Building Standards as a benchmark, the California Energy Commission (2005) predicts that 8 million homes are likely candidates for efficiency improvements.

“California’s nonresidential building stock is much more diverse than the residential… Large offices, retail and non-refrigerated warehouses represent approximately half of the total nonresidential space. These data indicate that over 5 million square feet of nonresidential buildings may benefit from efficiency upgrades amounting to significant further savings” (California Energy Commission, 2005).

End uses identified by the Interlaboratory Working Group (2000) in the commercial sector included lighting (25%), space heating (13%), office equipment (9%) and cooling (8%). Other end uses included water heating, refrigeration, ventilation, cooking, district services, automated teller machines, telecommunications equipment, and medical equipment (See Figure 1.20.4).

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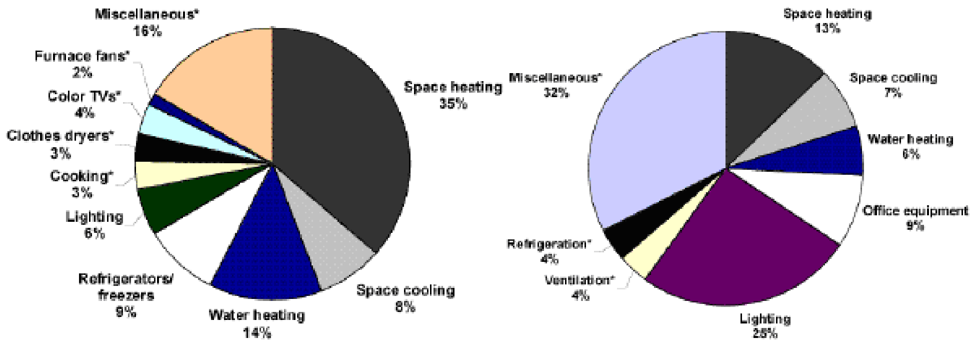
The Energy Commission (2005) estimates large potential energy savings in California buildings. “If one examines the technical potential alone, there could be savings of 12 percent of statewide electricity consumption, 17 percent of peak demand, and 20 percent of natural gas consumption. The cost-effective savings potential would be a subset of the technical potential but would still offer significant savings of 9 percent, 11 percent, and 5 percent, respectively.”

Figure 1.20.4: Primary Energy Consumption in the Buildings Sector by End Use, in 1997



Residential Buildings
Total Primary Energy Use in 1997 = 19.0 quads

Commercial Buildings
Total Primary Energy Use in 1997 = 15.2 quads

(Interlaboratory Working Group, 2000)

1.20.2 Studies on the Impact of Regulation

In the Western United States, Electricity sales increased 1.7% per year on average during 1990-2003 (Brown et al, 1998). Moreover, the Western U.S. is the fastest growing region in the country in terms of both energy consumption and population. And yet, while climate change effects are expected to increase overall energy demand even further, studies on energy efficiency demonstrate that reducing electricity demand growth by 0.5-2% per year is possible (Brown et al, 1998; Hill 2000).

National studies are consistently optimistic in estimating America's capacity for reductions in energy use and carbon emissions through technical, institutional, and economic transition to best practices. A study headed by Lawrence Berkeley Laboratory and Oak Ridge Laboratory, known as the Five Labs study, found that by instituting best practice measures including a 50$/ton cap on carbon emissions, emissions could be reduced 390 MMTCO2 from a baseline forecast between 1997 and 2010 to achieve 1990 levels by 2010 (Brown et al, 1998). 62MMTCO2 would follow from increased buildings efficiencies alone. Though differing in their assumptions and time frames, three other studies, by the Tellus Institute, by the National Academy of Sciences (NAS), and by the Office of Technology Assessment (OTA), considered that best practice measure would reduce energy emissions by a high of 2.8% per year in the Tellus study, to a low of 1.3% per year in the NAS study (Brown et al, 1998).The Tellus study predicted that carbon emissions could drop by 593 MtC by 2010, 22% below 1990 emission levels. The OTA study predicted reductions of 892 MMTCO2 by the year 2015, 281MMTCO2 of which would come from efficiencies in residential and commercial buildings.

Equally encouraging as these forecasts for emissions reductions are forecasts for the associated costs/savings. Building efficiencies are frequently predicted as the least cost, or highest savings, arena of reductions. The Tellus study predicted net annual savings of $50 billion in total, with net annual savings from building efficiency at around $30 billion (Brown et al, 1998) (See Figure 1.20.5). While the OTA predicted that the 892MMTCO2 reductions could be achieved with between $20 billion of savings to $150 billion of costs per year, the 86 MMTCO2 associated with residential building efficiencies were predicted to result in savings of between $25 and $15 billion per year, while the 195 MMTCO2 emissions reductions from commercial buildings were associated with between $28 billion in savings to $22 billion of costs per year (Brown et al, 1998) (See Figure 1.20.6). While the five labs study estimated between $34 billion in net annual savings to $5 billion in net annual costs in total, the reductions from building efficiency were predicted to be achieved at savings of between $19 and $9 billion per year (Brown et al, 1998) (See Figure 1.20.7). Finally, The NAS study predicted between 116$ billion in savings per year to $14 billion in savings per year in total, while the reductions from building efficiency were predicted at savings between $70 and $10 billion per year (See Figure 1.25.1).

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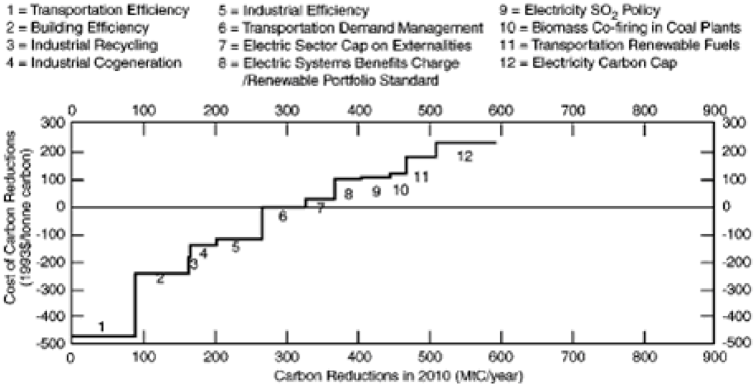
A study conducted by the Energy Efficiency Task Force (2005) in 18 Western US states, including California, found that best practice building efficiency standards could reduce energy consumption by totals of 1.4% in 2010 and 3.9% in 2020, and standards for public buildings could cut totals by an additional .2% in 2010 and .5% in 2020. Combined with other efficiency measures considered in the report, Carbon dioxide emissions could decline by 17% by 2020 and NOx emissions could decline by 7%.

Though the Energy Efficiency Task Force (2005) predicts little impact on electricity prices, overall energy use is projected to fall significantly, around 23% in 2020 in the best practices scenario, accounting for $21 billion dollars of savings in 2020 to Western State's consumers (Energy Efficiency Task Force, 2005). Because electricity and natural gas account for about 90% of building sector primary energy use, and because buildings account for large portions of primary energy and electricity use nationally, decreasing demand from buildings for energy could result in significant reductions to natural gas and coal use, and accordingly lead to the construction of far fewer power plants in the Western US (Interlaboratory Working Group, 2000) (See Figure 1.25.2).

Figure 1.20.5: Tellus Study



(Brown et al, 1998)

Figure 1.20.6: OTA Study

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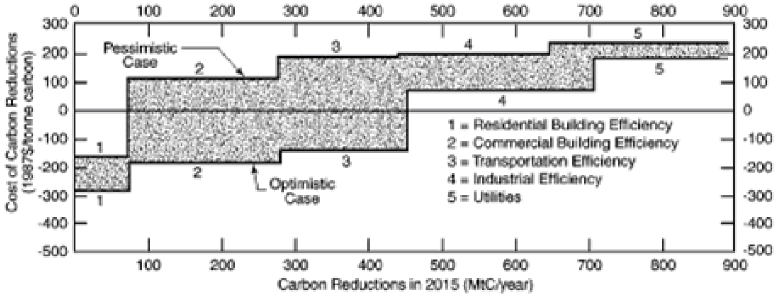
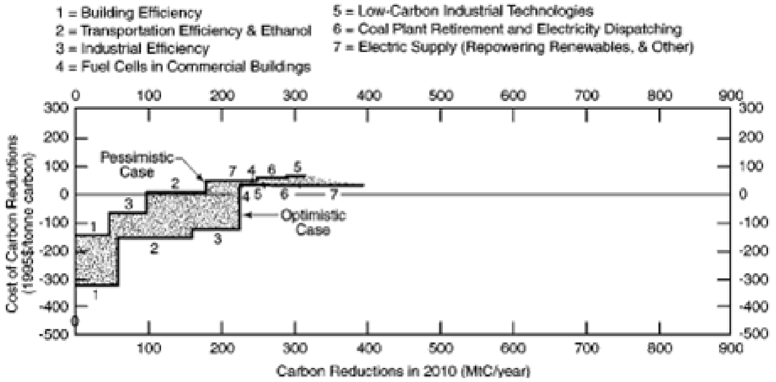


(Brown et al, 1998)

Figure 1.20.7: Five Lab Study



(Brown et al, 1998)

The 2000 report by the Interlaboratory Working Group goes into greater detail regarding its predictions for energy efficiency following from building and appliance efficiency standards and other energy management policies such as a 50$ per ton carbon cap in its best practices scenario. In their study, energy use falls to 1997 levels by 2020, and carbon emissions fall well below 1990 levels for the same year, while achieving net savings in energy service delivery. This is achieved by increased efficiencies in such end uses as space heating and cooling, water heating, and relies on increased market penetration from such technologies as electronic ballasts, commercial transformers, and heat pump water heaters. They also list “Break Through” technologies that could “fundamentally alter the current upward trend of buildings energy use,” such as thermally-activated heat Pumps, electrochromic glazing (Interlabortatory Working Group, 2000).

Of interest are other costs and benefits associated with the reductions. The increase in air quality should be associated with lower national medical costs per capita. Though net employment effects are expected to be positive, some industries like the railroad and mining industry will suffer business and employment losses due to predicted reductions in the demand for coal (Brown et al, 1998).

In addition to the net savings many studies predict, most studies find potential benefits to GDP to be in the tens of billions. In a study on the effects of energy efficiency in the Southwest, the Southwest Energy Efficiency Project (covering Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming) predicted $37 billion in gross economic benefits, an overall benefit-cost ratio of 4.2. The Energy Efficiency Task Force, (2005) predicted a benefit cost ratio of 2.5 for the Western U.S. under their best practices scenario, associate with total net economic benefits of $53 billion in net present value by 2020. “Jaccard and Montgomery (1996) provide a summary of costs of carbon reductions for 15 major US mitigation studies. Six of these studies (including both the NAS and OTA Studies) describe 11 different scenarios that use forecast years ranging from 2005 to 2015… Excluding two of the 11 scenarios with carbon reductions that exceed 50%, the remaining scenarios reported economic costs as a percentage of GDP, ranging from -0.2% to 0.5% (or a benefit of $20 billion to a cost of $50 billion in 2010, when the United States will have a $10 trillion economy)” (Brown et al, 1998).

Barriers to Efficient Technology: Why do we Need Standards?

If energy efficiency measures in buildings are cost effective to the point of generating cost savings, it might appear enigmatic that they are frequently neglected. If stakeholders behaved rationally to maximize benefits, then building standards, which as noted previously are only implemented conditionally upon their generating cost savings, would appear redundant. In fact, a host of market failures, institutional barriers, and social norms predispose builders against adopting efficiency enhancing standards independently.

Firstly, benefits from energy efficiency frequently do not accrue to the party who is in the best position to make the efficiency enhancing investment, resulting in split incentives such as between owners and renters (Brown et al, 1998) (See Figure 1.25.3). Pricing which reflects private, as opposed to social, costs gives additional incentives for builders to select inefficient technologies.

Users and businesses are often simply unaware of the financial and environmental costs from energy usage by a given technology, or the availability, technical applicability, or cost effectiveness of alternative technologies (Interlaboratory Working Group, 2000). Moreover, retrieving this information can itself be costly. Also, even if they do know, many consumers appear not to care. Neither Firms nor builders place a high priority on energy efficiency since the marginal benefit for any one firm is frequently a small portion of average variable cost. Not a cost relating to their core 'business', concerning output and the production process, consumers at all stages of the process demand too little energy efficiency. "A 10% rent saving can typically equate to a saving of \$30/m^2. A 10 per cent saving in electricity, cleaning, etc. might deliver savings of only \$3/m." (The Environmental…Buildings, 1999). As in the dilemma of collective action, benefits that may be vast when aggregated are frequently underinvested in when they are disseminated in such a way that that the gains to any one individual are small.

Firms further worry about the hidden cost of new investments such as increased risk or disrupted production (The Environmental…Buildings, 1999). Still, many scholars note that technologies for efficiency are underinvested in even if one takes into account risk and hidden costs (Koomey and Sanstad, 1994; Sathaye, Jayant, and Murtishaw, 2004). Firms do not appear to behave rationally, using discount rates which far exceed the returns they could expect in capital markets (Biggart, and Lutzenhiser, 2007; Sanstad et al., 2006). Train (1985) noted discount rates between 10% and 32% in measures to improve thermal efficiency, 4.4 % to 36% with regards to heating systems, and 3.7% to 22.5% for air conditioning. Though some of the premium may reflect added risk, many scholars see the rates as exorbitant, reflecting institutionalized consumer and managerial disregard for efficiency. These may become norms of a business's culture, disseminated throughout the organizational hierarchy when subordinates attempt to mimic the values and actions of their superiors in order to conform to perceived expectations (Biggart and Lutzenhiser, 2007).

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Of note is the paucity of R&D for energy efficiency in buildings. Notably underinvested in relative to other industries, this perpetuates low buildings efficiency. For instance, while industries average 3.5% of sales on R&D, the construction industry spends a paltry 0.2% of sales on R&D (Brown et al, 1998). This implies that, if normal levels of R&D could be reached, predictions for the technical potential of energy efficiency as well as for levels of economic benefit that could be achieved would need to be increased dramatically. Some of the failure to invest in R&D is already being targeted by government entry into the sector, offering grants for research and design purposes, including demonstration grants for early the application of findings in a commercial environment. Much of this work will be influential in creating future building standards such as the 2008 standards (California Energy Commission, 20005).

Concluding Remarks on the Impact of Regulation

Given the barriers to an efficient marketplace it is obvious that the continued promulgation of buildings standards is not only necessary, but frequently results in pareto enhancements to welfare. Since obligatory standards overcome barriers to efficiency by mandating efficient investments, they should be seen as an effective measure for combating climate change. Still, they are not ideal.

Since the costs and benefits of investment are diffuse, spread out over a range of stakeholders involved at each phase in the building's lifecycle, one might expect their effects to also be so dispersed. But, because standards can only target certain stakeholders in the building process, standards may convey the cost burden to a party less likely to benefit from the investment, as in the case of split incentives, or may create other distortions. Though many studies predict net savings associated with standards, some subgroups will face net costs. This may be ameliorated by inelastic demand in housing markets. The owners/builders that are most likely to be targeted should have sufficient market power to share cost burdens through prices, so that the standards should only slightly effect other economic decisions.

Still, targeting barriers to the adoption of efficient technologies directly should be considered as a natural compliment to implementing standards. While Sathaye, Jayant, and Murtishaw (2004) note that the significance of a given barrier to the implementation of efficient technology depends on the technology in question, there are known policy prescriptions for combating most of these barriers. "These include educating consumers and businesses, increasing the supply and visibility of energy-efficient products and services in retail establishments, offering consumers and businesses financial incentives to get their attention and stimulate greater willingness in adopting efficiency measures, removing inefficient products or buildings from the marketplace… and reforming pricing and regulatory policies" (Energy Efficiency Task Force, 2005).

A final and most profound synergy between standards and policies targeting barriers to efficiency lies in there contribution to changing preferences, creating novel institutions and social norms. In time, norms are internalized to become value based mandates, in addition to formal imperatives, becoming powerful motivating forces of human behavior and altering the premises and structure of our economic activity. In the long run, these should be the most powerful factors in structuring a sustainable society, relying on the organic decisions of individual economic actors rather than the mandates of ever changing administrations. Fortunately, preference shifts in favor of energy efficiency are already being observed, and barriers to efficiency, including pecuniary costs, are falling (Pimlott, 2007).

1.20.3 Scenario Description

In addition to the scenarios incorporated in our Baseline, the State of California has other initiatives to promote more efficient energy use patterns. While these are too numerous and diverse to be captured in a single scenario, the state has produced estimates of the aggregate relationship between public promotion expenses and private responses, and these provide a convenient reference to examining more comprehensive effects with a general equilibrium model. In particular, a recent CEC study by Messenger (2003) has estimated alternative time paths of public expenditure for promoting energy efficiency and linked these to increases in private aggregate energy efficiency. These results give us the raw material for additional energy efficiency scenarios.

1.20.4 Data Sources

Data used for these scenarios were obtained from the CPUC data synthesis conducted by Sanstad and Hallstein (2005) and Messenger (2003).

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1.20.5 Modeling Approach

For BEAR implementation, these scenarios were constructed by interpolating Messenger's cost estimates annually from 2003, debiting this to the general fund state government account in the California Social Accounting Matrix (SAM).[42] On the energy use side, we follow Messenger's analysis by assuming three scenarios for household energy use. In particular, we experiment with annual per capita reductions in residential electricity and natural gas use equal to -.5, -1.0, and -1.5 percent, respectively. Like Messenger, we implement these energy use reductions without specific reference to the technical means of achieving this efficiency. All households reduce electricity demand by the same annual percentages against Baseline values, and we further assume for simplicity that they incur no private adoption or other direct adjustment costs.[43] Finally, the reduced expenditure on electricity is reallocated to other consumption in existing shares, with no net increase in private savings.

It should be emphasized that, in the present analysis, we assume the electricity sector is one of homogeneous technology, including out-of-state capacity. Thus any reductions in electricity demand will reduce output for a hypothetical average generation facility, and total emissions will fall accordingly. In reality, technologies for electricity production are quite diverse, particularly in their fuel sources and emission characteristics. A prototype version of BEAR is currently under development to capture these structural characteristics, but for the moment we work with a single, representative firm model of the industry.

1.21 Vehicle GHG policies already underway

1.21.1 Sector Analysis

Being one of the world's largest economies, California's market for motor vehicles is quite large. Due to rising gasoline prices and changes in consumer choice has caused many big American motor vehicle companies to earn less profits due to he lessened demand for high-profit margin

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[42] The BEAR model uses a revised version of the 2003 California SAM documented in Berck et al (2004).

[43] Adding these costs would be a simple matter if estimates were made available.

cars such as SUVs. With increased global competition and consumer increase in demand for electronic and safety luxury additions to their cars, American auto manufacturer giants, General Motors Corporation and Ford Motors Corp. are losing market share and are facing deteriorating profitability (Standard and Poor's Industry Surveys 2006). The introduction of mandatory fuel efficiency standards and other policies to reduce GHG will further hurt these corporations. GM and Ford already plan to shut down many production facilities to cut costs.

The California Climate Change Emissions Policy will have two effects on the automobile industry. The first is that manufacturers will need to take to comply with the regulatory standards are expected to lead to price increases for new vehicles. However, many of the technological options they may choose to use to comply with new regulations are expected to reduce operating costs. The negative and positive effects of these policies will produce a small net positive effect to the economy as a whole. The vehicle price increase will be borne by purchasers and may negatively affect businesses. However, the operating cost savings from the use of vehicles that comply with the regulation will positively impact consumers and most businesses (ARB 2007). Low profitability with the adoption of new higher cost technologies in the short run will cause automakers to put price pressures on suppliers. However, increase use of these new technologies will also bring profits to those suppliers.

Industry Overview

The automobile manufacturers located in California include General Motors, Ford, and Toyota, whose other major plants are centralized in the Midwest and are also located globally. The motor plants are mainly located in suburban areas surrounding major cities, such as Fremont, Ontario, and Torrance, California. The size of the motor vehicle plants produce about 400,000 each and employ over 5,700 employees (AIAM).

See list of manufacturing and research and development plants in California.

Production

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The motor vehicle manufacturing industry forms generates one-sixth of all U.S. manufacturers' shipments of durable goods and consumes 30% of all the iron, 15% of all the steel, 25% of all the aluminum, and 75% of all the natural rubber bought by all industries in the nation (Pearce 2005).

The increased costs of materials such as steel, plastic resin, rubber, and aluminum is one of the concerns of the automaker's suppliers. The proposed cuts of about 3 million cars in U.S. production from Ford and GM will further hurt their suppliers. Currently, sustainability-conscious automakers such as Nissan, Toyota, and Honda are working diligently to install new technologies to increase efficiency gains. Nissan plans to introduce a new engine valve control technology that will contribute to a 10% reduction in fuel consumption and carbon-dioxide (GreenCarCongress.com).

Auto suppliers are in distress due to a combination of vehicle production cuts, high raw-material costs, unfavorable product mix shifts, and ongoing pricing pressure from a weakened customer demand caused most auto suppliers' earnings and cash flow to decline dramatically. They do not expect much reason for improvement in the near term.

Their main concerns include:

- the success of new vehicle launches, which if good will increase volume of parts demanded, or if bad will decrease the volume of parts demanded by the customer.
- high gasoline prices decrease the demand (though only modestly) for large, high profit margin vehicles, from which many auto suppliers generate a large share of their earnings.
- most auto suppliers are not able to fully offset increased costs of materials such as steel, plastic resin, rubber.
- the decline in market shares of the big American automakers also decreases their sales.
- high debt levels limit auto suppliers to access bank lines leading to negative investor sentiment in its ability to raise new capital.

Though the big automobile manufacturers are trying to protect their industry by suing California for raising the fuel efficiency standards, the smaller suppliers will be the ones hurt more drastically by the change in standards.

Cutting Production Costs

To cut production costs, automakers are simplifying parts and processes and cutting employee benefits. In automobile manufacturing, fewer parts means lower production costs and reduces assembly errors, which are also costly. Major automakers cut the number of parts they use in each component and vehicle by redesigning existing models and designing new models. In a typical product overhaul or redesign, part counts have dropped by 20% to 30% for individual car models and by as much as 50% for certain subsystems like bumpers and airbags (Standard & Poor's Industry Surveys 2006). Other ways of reducing production costs and improve quality is by reducing the number of stampings on sheet metal parts between 5 and 7 to 3. Manufacturers are also lowering costs by minimizing industrial waste and pollution. Nearly all component manufacturers now deliver their goods in reusable shipping containers. This saves money for automakers and their suppliers by eliminating excess packaging and disposal costs (Standard & Poor's Industry Surveys 2006).

Many auto manufacturers have just been neglecting the costs they could cut. For example, from General Motors Corporate website, GM in Mexico claims to recycle 94.5% of their hazardous and non-hazardous wastes. They did not eliminate disposal of hazardous wastes in landfills until the beginning of August 2003. The hazardous waste is now recycled or used as alternative fuel. Since 2000, land filled waste has been reduced from 7,369 metric tons to 444 metric tons during 2003. The financial savings from this are calculated to be $990,173. Additionally Non-Hazardous Waste landfill has been reduced from 3,188 to 2,340 metric tons from 2003 to 2004, which is a reduction of 27%.

Technology

New Materials

One method of increasing fuel efficiency is using lighter materials to build autos. Against improving fuel efficiency, U.S. consumers are demanding bigger, heavier SUVs and automakers continue to find efforts to increase performance and horsepower. Heavier, more powerful vehicles are typically less fuel-efficient. Passenger car sales accounted for only about 45.1% of the light vehicle market in 2005. Average fuel economy went down to 24.2 in 2005 from 25.1 in 1993. Despite the rising fuel prices, passenger car sales only made a modest comeback with market share rising 1%, though it continues to rise (Standard & Poor's Industry Surveys 2006). Increase use of variety of materials such as aluminum and plastic lowers the weight of vehicles and improves fuel efficiency. Steel use fell from 60% to 54.5%. The use of more aluminum to lighten cars is for better fuel efficiency, but costs much more. One kilogram of aluminum in car production replaces two kilograms of steel, which cuts weights down by almost 50%.

Volkswagen AG's Audi created Audi A2 in 2000 with an all aluminum body, end production in 2005 and replace it with steel in 2008. The Aluminum body costs $1,206 (based on June 30, 2005 conversion rate) per vehicle (Standard & Poor's Industry Surveys 2006). Higher priced aluminum cars sold poorly. Increase usage of lighter materials also makes designing cars much more challenging, which increase research and development costs.

Hybrids

Toyota's introduction of the first hybrid car, the Prius five years ago has caused it to decide to increase its production to one million hybrids annually in 2010 or soon afterwards. Cost-cutting efforts on the system's motor, battery and inverter were working so the cost structure would improve drastically by 2010. The executive vice president in charge of powertrain development expects margins to be equal to gasoline cars. "But sales began to suffer late last year after U.S. tax credits whittled down for the model, prompting Toyota to offer incentives of up to $2,000 on each Prius." Despite these pressure on the tough margins on the hybrid. Takimoto saw little impact on profitability before and after the incentives, mainly thanks to larger volumes produced — Prius production will rise by 40 percent to 280,000 units this year, which will continue to cut costs (MSNB.com). Incentives should be given to consumers who buy hybrid vehicles to increase demand and to help automakers make larger volumes to reduce average costs.

Diesel Anti-Idling

Diesel PM doesn't yet have a well-defined GWP and thus is not readily incorporated into the AB 32 reduction framework. Anti-idling will be opposed by diesel-users because the official effect is unknown.

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Variable Valve lift

This engine technology controls the flow of air and fuel into the cylinders and exhaust out of them. Optimum timing and lift settings are different for high and low engine speeds. Because traditional engines' timing is fixed, there are efficiency losses. The potential efficiency improvement is estimated to be 5% and savings over a vehicle's lifetime is $1400 (fueleconomy.gov).

Dual Cam Phasing

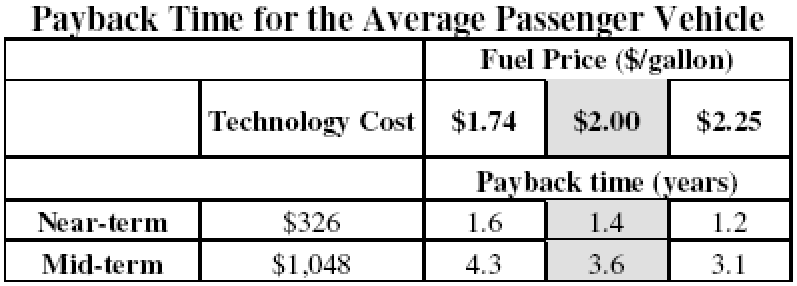
A control strategy for controlling internal combustion engines, particularly for controlling valve timing relative to crankshaft position. It optimizes valve timing at lower revolutions to help create a broad torque band and eliminate turbo lag (patentstorm.com)

Balance Sheets

The length of time it takes for a technology or package of technologies to recoup their costs is called *payback time* (calcleancars.org). The payback time for these technology improvements depends on the price of gasoline. These increases in vehicle price are more than made up over the life of the vehicle (Figure 1.21.1).

At the gasoline price of approximately $2.00/gallon, the average driver in California would regain the price of a near-term technology improvement in less than one and a half years of driving. The increased price of mid-term technology improvement would be made up in just over three and a half years of driving. Because gasoline prices have risen to about $3/gallon, the payback time for the near-term technology falls about a year. Over the lifetime of a vehicle, these savings add up. At a gasoline price of $2.00/gallon, near-term technology improvements will result in a net savings of over $1,700 to the average vehicle owner in California. Vehicles sold between 2009 and 2016 that meet California's greenhouse gas standards will save the operators of these vehicles $10.5 billion (in today's dollars) over the vehicles' lifetime. (calcleancars.org)

Figure 1.21.1:



Payback Time for the Average Passenger Vehicle

		Fuel Price ($/gallon)		
	Technology Cost	$1.74	$2.00	$2.25
		Payback time (years)		
Near-term	$326	1.6	1.4	1.2
Mid-term	$1,048	4.3	3.6	3.1

Source: California Air Resources Board

The profit margins of motor vehicle manufacturers that include both firms with net income and zero net income are much lower than the profit margins of firms with positive net income. This means that most small automobile manufacturers or suppliers are not able to sell their goods with high price to reap profits. Automakers have limited pricing power on consumers. Therefore, they look for price concessions from their suppliers. These companies in turn make demands on their own suppliers and so on down the production chain. Automakers will be hurt from the increase cost of more research and development for new environmental standards, which will in turn hurt their suppliers. Small suppliers typically have less financial strength, liquidity, and ability to resist their customers' demands, and therefore face the more difficult challenges. Decrease in the production of cars from major customers will be sharply lower leaving them in financial distress (Standard and Poor's Industry Surveys Volume 1 A-D2006).

Looking at Figure 5.2, the marginal cost and benefit for increase in miles per gallon in light trucks are the same at about 13 miles per gallon. "Once these standards are in place, signaling a federal commitment to reducing the fuel consumption of our nation's auto fleet, technological innovation may drive down the cost of new technologies, enabling more ambitious standards in later years" says DeCicco in the "Cost-Effective Targets for a 2008+ Light Truck CAFÉ Rule." Previous studies also indicate that light truck fleet fuel economy improvements of 50% or higher relative to recent levels "can be achieved within a decade cost-effectively through use of available technologies." A 50% improvement within ten years entails annual improvement rates of 4.1%/yr. (DeCicco et al. 2001).

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Conclusion

Because there are mounting pressures on automakers from all areas such as consumer change in tastes, decline in market share, increase in complexity of auto production with the integration of many electronics, fierce competition, the automakers’ profits are declining. With the institution of California’s new climate change emissions standards, all cars sold to the state must pass those standards, which basically implies the same standards everywhere else in the U.S. Like Toyota’s Prius production volume, other car manufacturers should follow suite in implementing cleaner vehicles in large volumes to cut down on marginal costs. Because consumers may not absorb the large volume at first, incentives should be given out to those who do choose to adopt the new technology. Taxes on large SUVs and other bigger cars that are less fuel efficient will cause some consumers to buy more efficient cars, reducing overall carbon emissions.

Because developing new cars and adopting redesign vehicles is very costly and requires a lot of capital investments, the transition will be slow. First, consumers must become more environmentally friendly and sacrifice some of their extravagant needs in order to convince auto manufacturers that energy should be spent on producing more green cars. Eventual adoption of this transition will then drive costs further down and make it feasible for every household to have a more efficient car.

Automobile manufacturers are battling California’s new higher efficiency standards in courts. They state that California does not have the power to set higher standards than the Federal government. Many automakers are looking into new technologies to make cars more efficient, but the process is slow and very costly. While GM and Ford are turning their business structures around, they cannot afford to lose any more resources or to continue to lose market share. Cutting costs may cause them to continue to close down plants or move them to cheaper locations such as Mexico.

1.21.2 Scenario Description:

These scenarios relate to the GHG reduction policies in the transportation sector, particularly vehicle technologies and policies to regulate pollution levels and facilitate higher levels of pollution efficiency. This scenario group refers to vehicle technology improvements and new standards embodied in a bill mandating new vehicle emission standards in California. This initiative for Vehicle Emissions Standards would

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require automobile producers to import and sell more CO2 efficient vehicles. In particular, we follow the classification of ARB’s report on Assembly Bill 1493 and use their vehicle cost and operating saving data directly in this scenario.

The direct effects of these policies are already being anticipated in a spirited debate between producer, consumer, and environmental interests, yet the ultimate economic impact is far more complex. Generally speaking, it is reasonable to expect that higher short run costs associated with new vehicle acquisition will be offset by longer run savings on automotive operating expenses (primarily fuel). Because these two factors are very prominent economic variables, they will set in motion a complex series of adjustments across the automotive, energy, and related sectors, with the ultimate consequences for households depending on supply responses, demand patterns, and other structural adjustments. In other words, this policy we set in motion a classic general equilibrium adjustment process across the California economy.

1.21.3 Modeling Approach:

Modeling these policies in the BEAR model is a routine matter because of its detailed treatment of household consumption and transport use patterns. The starting point is Baseline trends in supply and demand for transportation, to which we add intertemporal (ARB) data on vehicle cost increases and operating savings. The former are added to Baseline vehicle prices, while the operating savings are applied to household and industry light vehicle use over the forecast period. As one might expect, the former effect reduced purchasing power and GSP, while the latter has the opposite effect. The net result depends, as economists like to say, in initial shares and elasticities.

1.21.4 Data Sources and Description:

Data for all four scenario sets rely on a large body of research carried out by and for the California Air Resources Board. In the context of vehicle technologies and adoption, the most important sources for calibration data were CEC-ARB (2003) and CCAP (2005c). Several technical Appendixes to the former report provided calibration data for this and several of the following scenarios.

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1.22 Trucking Industry Measures

1.22.1 Sector Analysis

The trucking industry is a key support network to the state's economy and a large contributor to greenhouse gas emissions. Though significant emissions-efficiency gains have been made in the industry, room still remains to further emission reductions. Other than the costs of transitioning to cleaner technologies, few obstacles exist in the industry to implement AB32's measures. The history of environmental regulation of the industry makes it more receptive to regulation than industries unaccustomed to intervention and significant existing and developing technologies are available to help trucking firms meet AB32's provisions. Improved emission-efficiency practices have the simultaneous result of improved fuel efficiency, offsetting transition costs with reduced energy costs. The measures of AB32 ask that the trucking industry reduce emissions through a multiplicity of strategies. State efforts to in the implementation of AB32 can go a long way towards ensuring rapid and frictionless success in meeting its climate change goals.

The California trucking industry is dominated by a few, large national carriers but is largely composed by small, regional carriers. Approximately 60% of the 11,308 firms operating in California have less than five employees and earn less than half a million dollars in annual revenue (see Figure 1.22.1 and Figure 1.22.2). 75% of California trucking firms have less than 10 employees, 87% have less than 20 employees and 98% employ less than 100 employees. The majority of small trucking firms in California are privately owned and operated. The handful of large firms operating in California are publicly held companies. The trucking industry nationwide is a price competitive market. Large carriers and small carriers are both characterized by small profit margins and price their rates near marginal cost levels.

For more than seventy years, the California Trucking Association (CTA) has provided support services to trucking firms of all sizes and companies that provide services and products to the industry. Its members transport 85% of trucking freight carried in the state. Democratically run by member vote, the CTA has a strong Environmental Affairs Department which lobbies with state agencies to represent member interests and advices its constituency on compliance with environmental regulation.

Altogether, the California trucking industry transports a wide variety of goods and is classified by route distance and shipment size. Local routes deliver goods within metropolitan areas and their surrounding regions whereas long distance routes span multiple commercial areas. Truckload carriers (TL) are direct carriers that deliver large shipments door-to-door from origin to destination whereas Less than Truckload (LTL) carriers sort combined shipments in distribution hubs to coordinate a flow of goods from multiple clients to nearby destinations. 60% of the carriers operating in California are long haul carriers delivering goods in and out of the state in long distance routes. The remainder of the state's carriers are short haul carriers traveling local routes of 50 to 700 miles within the state and within the West Coast region, including Mexico. The LTL market has higher barriers to entry than the TL market due to the costs of large sales forces, logistics technology and distribution terminals. Compared to other industries, however, both sectors have relatively low barriers to entry, are highly competitive and have low profit margins. Trucking firms differentiate themselves by the routes and type of goods they are authorized to carry.

Nationally, the trucking industry dominates the transport of high value goods, carrying 55% of national freight in weight and 75% of national freight in value. It carries 70% of construction goods like steel, sheet metal, wire, pipes and lumber and 85% of household goods like food and furniture. The trucking industry's main competitor is the rail freight industry. Railroads have cost advantages in long distance shipping in routes greater than 500 miles. Rail freight is preferred in the shipment of heavy commodities, like coal, but is increasingly being turned to for interstate shipment of manufactured goods as well. Intermodal collaboration between railroads and the trucking industry coordinates freight transport between the competing sectors. Other competitors to the trucking industry are pipelines, domestic water freight and air freight.

Competitiveness within the industry is characterized by a firm's financial strength, the quality of its salesforce, availability of tracking technologies, route coverage, efficient claim settlement, fleet size and quality, insurance coverage, safety records and the type of freight firms are authorized to carry.

The industry is highly regulated in terms of the types of goods each carrier is certified to transport, environmental standards and safety standards. The industry underwent significant deregulation in the Motor Carrier Act of 1980, increasing cost competitiveness, reducing barriers to entry and increasing industry efficiency, especially in terms of carriers' abilities to transport full shipments on return trips.

The regional scope of the industry is key to its structure. National carriers with parent companies outside the state are generally operated by California subsidiaries. Routes in the state are connected to shippers and destinations throughout the North American continent. The crossing at Otay Mesa, CA is a significant truck portal between the US and Mexico, handling more than $10 billion in traded goods in 2004.

The trucking industry is a growing industry in California. The transport of goods to and from the Los Angeles and Long Beach ports, for example, is forecasted to increase by 250% from 2005 to 2025 due to increased import activity. Thanks to an abundance of industry innovations which reduce greenhouse gas emissions, high growth rates do not imply increased emission rates or greenhouse gas concentrations.

Due to the number of firms operating in the industry, the small scale of the majority of its firms and the industry's network characteristics, it is challenging to discern precise cost and production statistics for the industry specific to California. This analysis will qualitatively consider the production factors, technologies, costs and perspectives of the trucking industry, providing quantitative state and national data when available. A snapshot of the overall industry will be followed by nuances among national and regional carriers and an industry wide prognosis.

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1.22.2 Industry Overview

Production

Production in the trucking industry is measured in ton-mileage, indicating the mass of goods delivered in relation to mileage incurred. While ton-mileage within the state is difficult to separate from national data, mileage of the state's largest heavy-duty trucks, those carrying loads heavier than 33,000 pounds, traveled over 25 million daily miles daily 2005, topping 9 billion annual miles.

Nationally, trucking carries nearly 30% of American freight volume in ton-mileage. Alternate methods of freight include railroad (39%, due to railroad's dominance of heavy commodities like coal), pipeline (19%), domestic water (12%) and air freight (less than 0.5%).

Inputs

Trucking inputs include: diesel fuel, trucks, trailers, tires and equipment-related inputs, driving labor, management labor, distribution hubs and logistics technology.

Significant to AB32, factors on trucking's energy use include fuel prices, fuel efficiency and fuel composition.

Diesel fuel prices fluctuate between periods but have an overall increasing pattern industry wide and are expected to continue rising in future years. Fuel price per gallon is exogenous to the industry but significant savings opportunities exist to reduce fuel costs with improved fuel efficiency.

Fuel efficiency is a significant factor to both trucking profitability and emissions. Nationally, energy input of freight transport is expected to increase from 2005 levels by 27% by 2010 and 49% by 2020. An equivalent increase in California's fuel input for trucking is significant impetus to improve fuel efficiency and offers a significant opportunity to reduce greenhouse gas emissions. As proposed regulations are implemented in the state, gains in the industry's fuel efficiency would be partially dictated by regulation measures and partially dictated by firms' inherent motivation to maximize competitiveness in face of rising fuel costs.

Fuel composition would be altered by proposed regulation by blending increased amounts of biomass fuel in diesel stock. Increased use of biofuel changes the composition of the industry's emissions.

AB32 also considers the industry's use of trucks, trailers, tires and equipment-related inputs. Arenas of input decision making that offer significant gains in fuel and emission efficiency include the use of driving labor, management labor, distribution hubs and logistics technology.

In regards to a cap and trade mechanism, the trucking industry will only be affected by a fuel-based allowance strategy. A fuel-based allowance cap and trade mechanism will have the downstream affect of a fuel tax, increasing marginal costs to trucking firms. A fuel-based cap and trade mechanism requires no technological or monitoring adaptations from the industry. Carbon caps and monitoring would occur at point sources upstream of the trucking industry; it would not be involved in the trading process.

Outputs

Trucking outputs include: transportation services and emittants, including greenhouse gases. Effects on trucking outputs include trucking demand, economies of scale and economies of utilization.

The most significant determinant of trucking demand is consumer demand. Nationwide, fluctuations in trucking demand closely shadow fluctuations in Gross Domestic Product (GDP). In developed economies, trucking demand is near unit-elastic to GDP, increasing slightly with gains in economic wealth. As one of the largest global economies, California's trucking demand is similarly driven by the rate of economic expansion.

Other significant drivers in trucking demand include the price of fuel and insurance costs. As the cost of both fuel and insurance increases, trucking demand decreases. Increasing adoption of practices which maximize tons of goods carried per mile minimize the dampening effects that rising fuel and insurance costs have on industry demand.

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Industry wide, economies of scale do not result in gains in transportation services. While this is slightly less so in the LTL sector which benefits from increased ton-mileage per distribution hub, the large number of firms in the overall industry is evidence that firms with a focused scope have similar profit potentials as larger firms broader in scope. In terms of pending regulation, the significance of this characteristic is that, without the threat of monopoly power, trucking prices are not likely to increase above commensurate increases in trucking costs due to the price-minimizing pressure of industry competition.

Economies of scale are not known to affect industry emissions.

Economies of utilization have significant impact on both ton-mileage of transportation services and industry emissions. Economies of utilization allocate fixed costs and emissions over increased output, maximizing ton-mileage per dollar spent and pollution emitted. Equipment usage is limited by federal labor regulation limiting driver hours of service but can be greatly maximized by technologies and practices that improve fuel and ton-mileage efficiency.

Technology

Due to existing air quality regulation, basic technology employed by California's trucking industry is relatively homogenous in terms of emissions and fuel efficiency. How the industry's trucks and trailers are used by individual firms, however, can vary efficiency measures depending on route geography, type of goods carried and driving behavior. Regulation pressures have been shown to hasten the adoption of costly technologies. Beyond extending efforts to regulate the fuel and emissions efficiency of trucks purchased in California, emissions can be further reduced by altering three industry characteristics:

1. characteristics of the vehicles currently in use, i.e. improving truck and trailer aerodynamics, reducing tire resistance, replacing existing engines with cleaner engines or retrofitting vehicles with emission control systems

2. characteristics of fuel sold in California, i.e. blending diesel with biodiesel

3. how vehicles are used in California, i.e. optimizing driving behavior and route efficiency

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AB32 considers emissions reductions in all of the above strategies. It is significant to note that industry investment in emission-reduction methods offer simultaneous savings benefits in fuel efficiency gains among firms. Extension of existing vehicle and engine scrapping programs in the state would hasten industry adoption of its measures.

Technology adoption that helps firms meet AB32 provisions before its implementation can be registered with the California Climate Action Registry. Registration reduces firms' transition costs without loosing recognition of improvements incurred early on. To date, only one firm out of the industry's 11,000 plus firms has signed on to the registry.

Following is an analysis of AB32's provisions related to trucking technology and the industry's ability to meet regulation requirements with existing capabilities:

Diesel Anti-Idling

THE GOAL: To extend existing anti-idling regulation to further climate change emission reductions by about 4% with significant cost savings to both the industry and trucking consumers and substantial air quality benefits.

INDUSTRY VIABILITY: National estimates of engine idling for the purpose of powering cab amenities and running electrical appliances range from 1000 to 5000 hours per year per truck. The industry employs at least four alternative methods of providing cab heating, cooling and electrical supply without the use of idling the engine:

1. Direct fire heaters which route heating between the cab and the engine with a small combustion flame and heat exchanger
2. Auxiliary power units (APUs) mounted externally on the truck to provide heat, electricity and air conditioning

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3. Automatic engine idling systems which start and stop truck engines automatically to maintain specified temperatures or minimum battery voltage

4. Electrification of truck stops which provide electricity to trucks without engine use or the use of auxiliary units

Truck idling can also be considerably reduced through route mapping that minimizes idling time. Support services are available to the industry, for example, which maps routes without left hand turns, reducing idling time and improving fuel efficiency. Emissions have been reduced in similar ways by automating toll booths for heavy duty trucks.

Industry concerns about anti-idling efforts include safety concerns, retrofitting costs and the unknown reliability of direct fire heaters. The last concern can be refuted by the evidence that 55% of European long-haul trucks are outfitted with direct fire heaters without increased safety hazards or equipment failure.

Another industry concern about anti-idling strategies is that automatic systems are disruptive to long-haul drivers when sleeping. Adoption of technologies unsuitable to trucking needs would not be widely accepted. Improvement to the engineering of automatic systems would be desirable.

It should be noted that the four methods of providing cab heating, cooling and electrical supply do not have cumulative emissions reductions; they are alternate choices. Extension of truck stop electrification would reduce the need for direct fire heaters, APUs and automatic idling systems. If truck stop electrification is not widely extended, firms could choose between direct fire heaters, APUs and automatic idling systems as alternate methods to meet AB32’s provisions.

Current limitations on truck idling are enforce by the state’s Air Resource Board’s inspection teams. Participation of local enforcement agencies, including California Highway Patrol, police and local air district inspectors would improve AB32’s effectiveness at reaching its proposed goals.

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All technology based anti-idling strategies currently have a low market penetration, offering substantial opportunities to increase fuel efficiency and reduce greenhouse gas emissions with cost savings benefits to the industry.

Hdrofluorocarbon (HFC) Reductions

THE GOAL: In an overall effort to reduce the use of hydrofluorocarbons, require that the trucking industry:

1. use only low-Global Warming Potential (low GWP) refrigerants in new medium and heavy-duty vehicles not already covered by existing regulation by 2010
2. limit the use of GWP refrigerants in refrigerated trucks
3. be subjected to refrigerant use and leakage checks as part of existing smog-check inspections

INDUSTRY VIABILITY: Existing environmental regulations already cover most vehicles employed by the state's trucking industry and dictate the availability of vehicles sold in the state. There are no known technological concerns to extend the reduction of HFCs to AB32's standards within the industry.

Alternative Fuels: Biodiesel Blends

THE GOAL: To change the composition of California diesel fuel to include 1 to 4% biodiesel.

INDUSTRY VIABILITY: Biodiesel blends of 1 to 4% can be used by existing technology stock without mechanical alterations. There is discussion, however, that fuel efficiency decreases with increased percentages of fuel from biomass sources. If this proves to be the case, price pressures on diesel fuel would be threefold: first, the price of diesel fuel has been increasing in recent years and is expected to continue

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to rise in the future. Second, the blending of diesel fuel with biofuel is forecasted to raise diesel fuel prices. Thirdly, reduced fuel efficiency due to the addition of biomass will increase fuel demand.

Regional implementation of biofuel blending in the state's neighboring economies would minimize leakage due to trucks fueling up at stations across state boarders.

Heavy Duty Vehicle Emission Reduction

THE GOAL: To reduce vehicle emissions in the trucking industry through a variety of measures, including: improved vehicle aerodynamics, climate-engine based improvement efficiency, vehicle weight reductions, rolling and inertia resistance improvements and educational programs on optimal vehicle operation.

INDUSTRY VIABILITY: Significant opportunities exist for emission reductions in this category. Specifically:

- Improved vehicle aerodynamics increase fuel efficiency at highway speeds by reducing aerodynamic resistance. While efforts to improve cab aerodynamics are approaching saturation levels in the industry, improvements to trailer aerodynamics still offer substantial room for emissions reduction. Low-tech, modular solutions which, for example, reduce the gap between tractor and trailer improve fuel and emissions efficiency.

- Climate-engine based improved efficiency, such as the use of low friction engine lubrication and low friction drive train lubricants have low adoption rates in the industry, thereby offering considerable opportunities to reduce greenhouse gas emissions. Additionally, climate-engine efficiency can be improved without scrapping entire trucks by replacing existing engines with cleaner technologies.

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- Vehicle weight reductions similarly have low adoption rates in the industry and offer considerable opportunities to reduce greenhouse gas emissions.

- Rolling and inertia resistance improvements, such as wireless tire pressure monitoring systems, tire inflation systems and the use of wide-based tires offer some of the greatest opportunities for the industry to maximize fuel efficiency and reduce greenhouse gases. All approaches currently have low market penetration rates, offering considerable opportunities to reduce emissions.

- Wide-based tires which replace the typical dual-tire configuration with singular, wide tires have thus far been received by the industry with skepticism. Trucking's concerns include that wide-based tires are not consistently legal throughout the continent and that they do not offer the same back up benefits that dual-tire configurations offer when tires blow out. Counterarguments claim that wide-based tires are now legal in all fifty states and that the presence of tandem axels in heavy duty trucks prevent vehicles from being immobilized when wide-based tires fail.

- If paired with effective monitoring and enforcement systems, educational programs on optimal vehicle operation also offer substantial emissions reductions. Encouragement of speed reduction, for example, improves fuel efficiency and reduces greenhouse gas emissions. Truck fuel economy drops as highway speeds increase above 55 miles per hours (mph). An increase from 55 mph to 60 mph reduces fuel efficiency by 7.1 miles per gallon (mpg). An increase from 60 mph to 65 mph reduces fuel efficiency by 6.5 mpg. Further increasing speeds to 70 mph further diminishes fuel efficiency by an additional 6.1 mpg.

Fuel Efficient Replacement of Tires and Inflation

THE GOAL: To improve fuel efficiency by the development and adoption of more fuel-efficient tires and tire usage.

INDUSTRY VIABILITY: As highlighted in the above section, increased use of fuel-efficient tires and tire usage is well developed in the industry and low market penetration rates offer significant fuel and emission efficiency improvements.

Logistics Technology

A substantial area for emissions reductions unmentioned in AB32 is improvements in trucking logistics. Internally motivated by cost and service competitiveness, significant logistics gains have improved fuel and emissions efficiency in the industry. Continued logistics improvements that can be adopted include:

- Route efficiency technologies that optimize the location and status of trucks and trailers with fuel stops, distribution hubs and final destinations.
- Revenue potential technologies that maximize earnings per ton-mile
- Load maximizing technologies that balance inbound and outbound loads to ensure full loads on all trips. Though containerization in the later half of the twentieth century and the Motor Carrier Act of 1980 greatly reduced empty and out-of-route miles, long term contracts, shipment planner software and coordinating services offer further potential to minimize emittant per ton-mile by creating shorter, dedicated and non-random routes and minimizing empty, circuitous miles.

1.22.3 COSTS

While it is difficult to discern average and marginal costs for the typical trucking firm in California, it is insightful to consider cost effects of rising energy prices, cost effects of improved fuel efficiency and cost factors characteristic to the industry.

Cost Effects of Rising Energy Prices

A key contributor to the industry's average and marginal cost is the price of diesel fuel. In July 2006, the average diesel fuel price in representative Californian cities was $3.175 per gallon. If the typical long haul truck has an annual mileage of 98,000 and a fuel economy of

6.1 mpg, the marginal cost of fuel per mile during this period was $0.52, totaling fuel expenses per typical truck at $51,008. Increases in fuel prices have a one to one correlation with marginal and total fuel costs; a one percent increase in fuel prices results in a 1% increase in both marginal and total fuel costs.

Cost Effects of Improved Fuel Efficiency

Improved fuel efficiency has a one to one correlation with marginal and total fuel costs as well, reducing costs as efficiency improves. A $2000 investment in improved fuel efficiency is covered by the first year of energy cost savings by a 5% minimum fuel efficiency improvement. A $3800 investment is covered by the first year of energy cost savings with at least a 10% fuel efficiency improvement. Low interest rates and long lifespans of efficiency measures further finance improved fuel efficiency. Greenhouse gas emissions are reduced by the industry at a cost savings to firms.

Cost Factors Characteristic to the Industry

Fixed costs in the trucking industry are expenses incurred no matter how many miles are accumulated and variable costs are those attributed to mileage. Trucking fixed costs include: equipment costs, interest rates, license fees and taxes, insurance, management costs and overhead costs. Significant variable costs in the sector include maintenance and repair, fuel costs, labor and tires.

Between firms, fixed and variable costs vary significantly depending on the type of carrier the firm is, the geography of their routes and the type of products they carry. As an industry, the composition of fixed and variable costs are determined by the type of goods and routes the state's economy demands. In an industry as competitive and with as many firms as the trucking industry, as statewide demand varies, firms emerge to cover underserved markets and withdraw from saturated markets.

Among fixed and variable costs, it is important to consider the degree to which trucking firms and the industry have control over cost variables. Exogenous costs beyond decision makers' control include fuel, tire, maintenance and repair expenses, license fees and taxes, insurance costs and interest rates. Business decisions made by firms and the industry are related the decision-variable costs of equipment, overhead, management and labor expenses. Driving practices and equipment usage use decision-variable costs to manage exogenous costs. Both firm competitiveness and industry viability is increased as decision-variable costs and performance practices minimize the effect of exogenous expenses.

1.22.4 Perspectives: Uncertainties, Pressures And Trends

Uncertainties and Pressures

Current pressures on the trucking industry include:

- Fluctuating diesel fuel costs
- Rising insurance costs
- Fluctuations in consumer demand
- High driver turn over rates, reported to be as high as 100% annually
- Driver shortages, especially for long haul routes
- Rising health and liability costs
- Price competition among firms
- Increasing competition from the rail freight industry in the shipment of manufactured goods and from double stacked railcars

Trends

Trucking is considered relatively immune to economic recession. Despite economic slowdowns which reduced manufacturing and consumer demand in the early 2000s, the trucking industry experienced national growth between 1995 and 2005. The lowest growth rate was 0.7% experienced between 2002 and 2003. The highest growth rate was 4.5%, experienced between 1996 and 1997. The average growth rate in the 10 year period was 2.44%. As California's economy experiences fluctuations in growth rates, the trucking industry is expected to experience commensurate changes in demand.

Due to an improved economy and rise in manufacturer's shipments, intercity national freight volume is expected to grow at a rate of 2.5% in ton-mileage through 2010. This is slightly higher than the expected demand increase of freight services in general (including railroad, pipeline, domestic water transport and air freight) of 1.9%. This indicates that trucking freight is expected to remain competitive in coming years. Intermodal rail and trucking collaboration is expected to continued growing while domestic water, pipeline and air freight shares of freight transport is expected to remain constant or decline.

Transborder trucking freight with Mexico as part of NAFTA trade is also expected to grow in coming years.

Increasing use of just in time inventory practices as manufactures and retailers move to "zero inventory" methods mean that:

- an increase in distribution hubs within two days distance between inputs and manufactures and between manufacturers and retailers.
- that firms able to offer the most inclusive package of logistics, storage services and customer accessible tracking systems are well positioned to absorb a good portion of industry growth. Larger firms tend to offer these services more frequently than smaller firms.

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- Increased investment in logistics technologies industry wide.
- Shortened supply routes.

Continued route maximization practices are expected due to increasing fuel prices and competitive pressures.

Stable trucking rates due to price competition are expected in the industry in coming years.

Research and development in safety measures, including cab mounted computers that reduce accidents and improve communication between drivers with dispatchers.

Research and development in computerized systems that direct trucks to optimal speeds.

Research and development in shipment planner software that reduces empty trailer miles.

Increasing horizontal integration and alliances with railroad firms.

1.22.5 National Carriers Operating in California

National Carrier Industry Overview

The 6786 firms in the state's national carrier sector make up 60% of California's trucking industry. 60% of national carriers operating in California earn less than half a million dollars in annual state revenue; 90% of the state's national carriers earn less than $5 million in annual state revenue. (Figure 1.22.3 and Figure 1.22.4)

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Due to the network characteristics inherent to the trucking industry, many national carriers operating in California are not owned in California. National carriers with parent companies outside of California are oftentimes operated by state subsidiaries. Leading firms earning more than $50 million in annual revenue include FedEx, Roadway, UPS and Estes Way. Dominant, large national carriers are price competitive with the populous fringe of smaller, national carriers. Some overlap in the LTL and TL sectors occurs among national carriers.

National Carrier Production Factors

National carriers face the same general inputs and outputs characteristic to the overall industry, with heavier use of management, distribution hubs, logistics and marketing than regional carriers. National carriers benefit most in the industry from economies of scale and have improved capabilities for maximizing economies of utilization due to sophisticated management practices and logistics technologies.

Figure 1.22.1: 2006 Regional Carrier Firm Distribution by Revenue

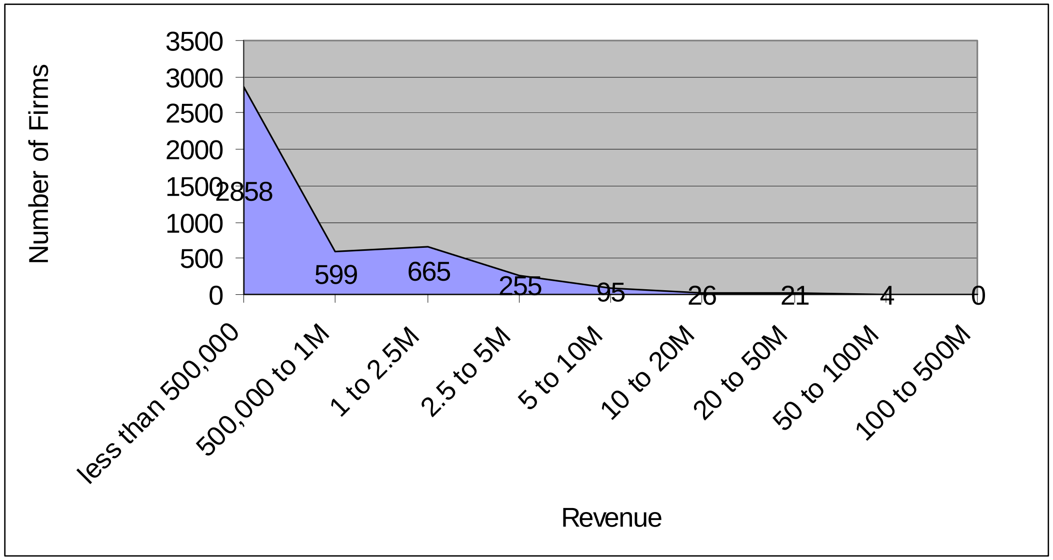

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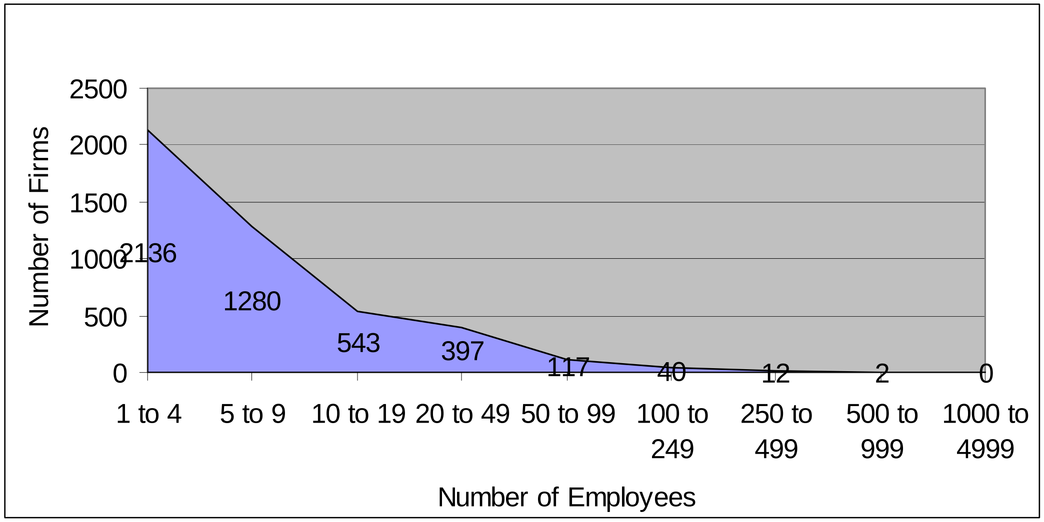
Figure 1.22.2: 2006 Regional Carrier Distribution of Firm Size in # of Employees



National Carrier Technology Factors

Large, national carriers have been a driver of fuel and emissions efficiency innovations in the industry. FedEx, for example, is in collaboration with environmental think tanks to design and adopt more efficient trucks that reduce fuel use and emission rates. Likewise, UPS has gained national attention for its collaboration with services that reduce engine idling through the minimization of left hand turns.

Larger firms in the national carrier sector are better positioned to coordinate and finance efficiency improvements to the characteristics of existing vehicles and improvements to vehicle use.

Zero national carriers have registered with the California Climate Action Registry.

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National Carrier Cost Factors

National carriers generally face the same energy costs as regional carriers within California but have the advantage of fueling up in neighboring states with lower fuel costs. Depending on the carrier's route, this can amount to energy savings as much as 4 to 12%. Firms that have vertically integrated in the petroleum industry have the advantage of dedicated access to diesel fuel, but federal regulation of the industry ensures that vertical integration does not give firms a cost advantage.

National carriers may benefit less per mile in fuel efficiency gains because of its tendency to use newer, cleaner stock, the diminishing capabilities of fuel efficiency efforts already made and because national carriers run more highway miles, optimal operating conditions for heavy duty trucks.

National carriers have higher fixed costs than regional carriers due to their heavier use of management, distribution hubs, logistics technology and marketing, but face the same variable costs of maintenance and repair, fuel and tire expenses.

National Carrier Perspectives – Trends & Uncertainty

Regardless of AB32's measures, fierce competition in the national carrier sector will continue to drive fuel and emissions efficiency through technology innovation and maximization of economies of utilization.

Due to its dominance of long haul routes, the national carrier sector is more affected by hours of service regulations and high turn rates than regional carriers.

1.22.6 Regional Carriers Operating In California

Regional Carrier Industry Overview

The 4529 regional carriers operating in California make up 40% of the state's overall trucking industry. Similar to the characteristics of the overall industry, the regional carrier sector is comprised of a few leading firms and a large competitive fringe. Leading firms in the industry with revenues greater than $50 million include Adams Grain Company, Sunny Express and Unity Courier Services. More than 60% of the state's regional carriers earn less than half a million dollars; 90% of California's regional carriers earn less than $2.5 million. Regional carriers tend to be privately owned firms. (Figure 1.22.1)

<u>*Regional Carrier Production Factors*</u>

Regional carriers have the same inputs and outputs of the overall industry with less of a need for sophisticated tracking logistics and management practices due to its dominance of shorter, dedicated routes. The dominance of short haul routes results in lower fuel and emissions efficiency than industry averages due to more stops per ton-mile, less highway miles and increased intercity miles in congested areas.

Figure 1.22.3: 2006 National Carrier Distribution of Firm Size by Revenue

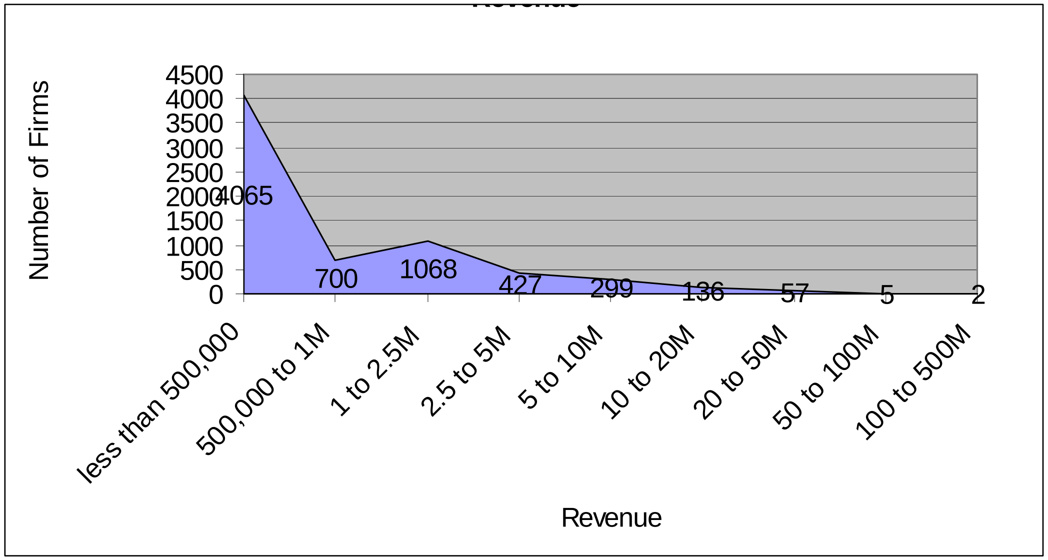

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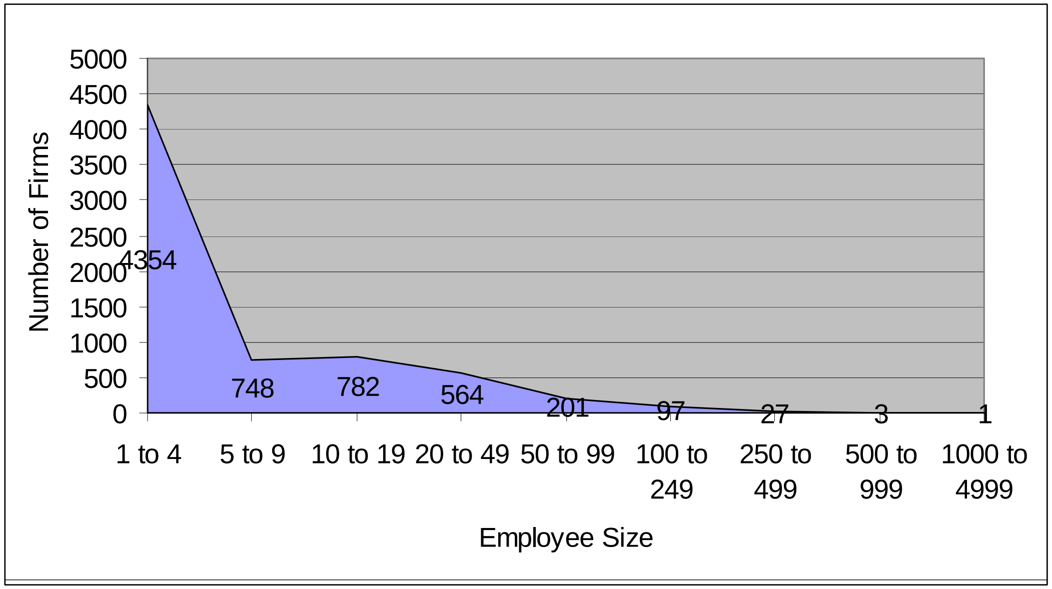
Figure 1.22.4: National Carrier Distribution by Employee Size



Regional Carrier Technology

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Due to purchasing patterns in the overall industry, regional carriers have been historically slower to adopt cleaner technologies than national carriers. Regional carriers are positioned to gain the most from fuel efficiency measures as older stock is replaced and because of the room for efficiency improvement in intercity transport.

Only one regional carrier is registered with the California Climate Action Registry: Bill Signs Trucking of San Diego. Bill Signs Trucking is the the industry's sole firm on the Climate Action Registry.

Regional Carrier Cost Factors

> Regional carriers face energy, fixed and variable costs standard to the industry. Regional carriers do not share national carrier advantages of fueling up at lower costs outside the state with the exception of those firms operating routes near state boarders.

Regional Carrier Perspectives – Trends & Uncertainty

As a sector, regional carriers face less competition from the industry's rail, pipeline, domestic water and air freight competitors due to the flexibility trucks have in carrying more specified routes.

Between firms, regional carriers are price competitive due to the number of firms operating in the industry.

1.22.7 Conclusion: Prognosis for Policy

The success of the state's trucking industry is an indicator and result of California's economic well being. Participation of the industry's firms in meeting the goals of AB32 will greatly reduce greenhouse gas emissions in significant and needed ways. Fortunately, trucking is well positioned to implement AB32's measures due to innovative fuel and emission efficient technologies currently available to the industry. In addition to the incentives AB32 provides in reducing emissions, the industry's competitive environment creates considerable internal motivation to improve fuel and emissions efficiency as a means of profit maximization. Gains made in fuel and emissions efficiency have the benefit of cost savings to firms and the industry as a whole. If AB32 regulation results in higher prices to trucking consumers, the make up of the industry dictates that costs will not simply be passed through to customers; any resulting price increases will not likely rise above commensurate cost increases to trucking firms. Due to the history of environmental regulation in the industry, trucking firms are more receptive to and have more support networks in place to implement AB32’s provisions than industries unaccustomed to regulation.

The trucking industry is sufficiently armed with strategies relating to all its inputs in order to comply with AB32. The network characteristics of the industry make regional collaborations with California’s neighboring economies ideal. In particular, West Coast collaborations to standardized biofuel blending with diesel fuel would minimize emission leakage. Additional collaboration with industry groups, such as the California Trucking Association, and industry leaders would help facilitate swift implementation of AB32 measures.

1.23 Manure Management

1.23.1 Sector Analysis

California's livestock population is a major contributor to the state's overall greenhouse gas (GHG) emissions. Of this population, dairy and beef confined animal feeding operations (CAFOs) are the most significant emitters and are also the best potential source of major reductions. As ruminants and large producers of manure, cows are responsible for the production of large quantities of methane, which is 21X more effective GHG than CO2. While there are both dairy and beef cattle feedlots in California, the ratio of dairy to beef cattle in the state is over 2:1 (1,569,693 dairy cows and 707,000 feed cattle) and growing (Livestock 2006). Due to this trends of increasing dairy numbers and decreasing beef cattle numbers and to the generally greater attention that dairy has received as a source of GHG mitigation, this report will focus on the Dairy industry in California, yet much of it will apply to both.

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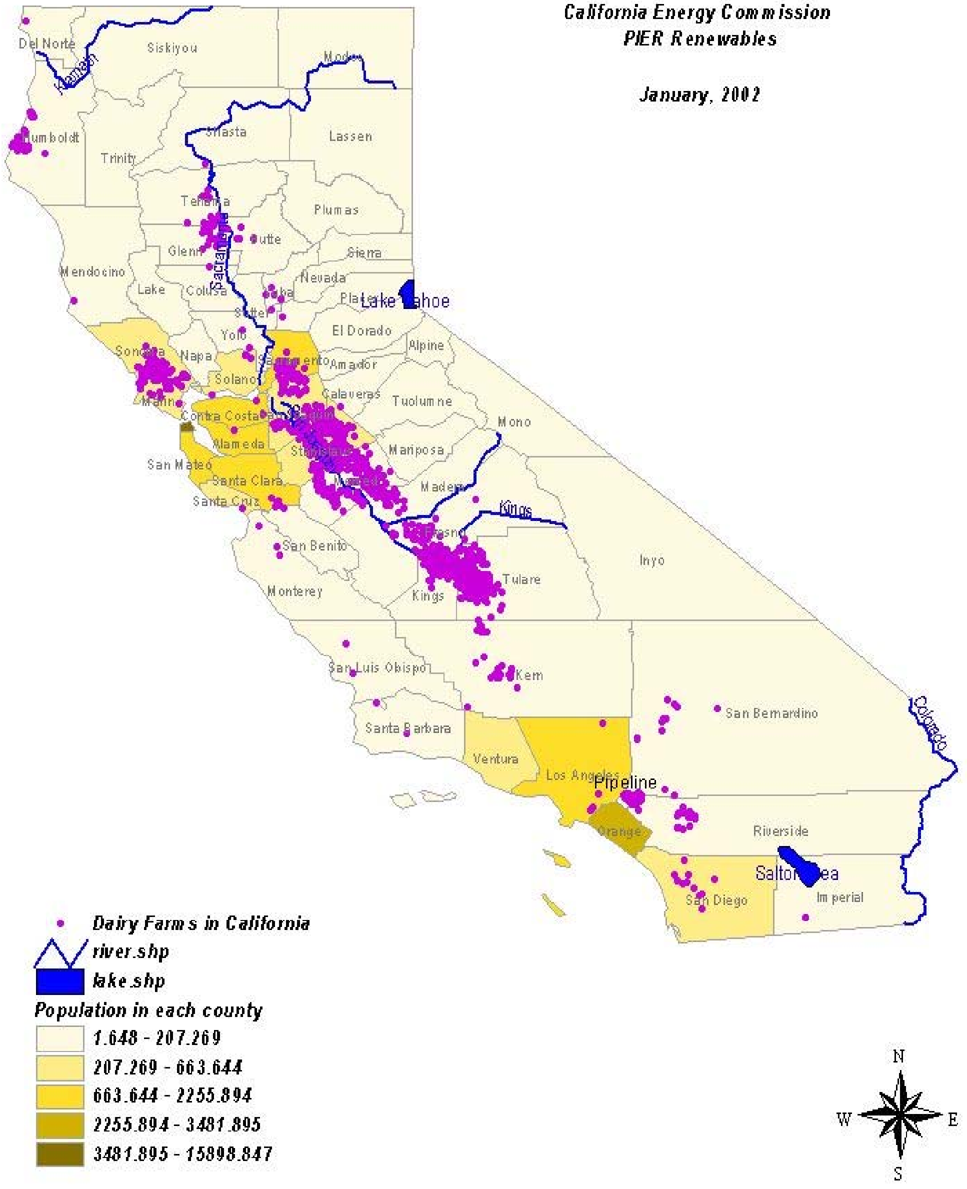
The Industry

“Although beef cattle populations have declined over the last 12 years, the dairy cattle population has increased significantly. California is the leading dairy state in the nation and dairy products are the state’s number one agricultural commodity” (CEC emissions and sinks page 42). In 2006, California dairies accounted for about 21.2% of the nation's overall milk production, followed by only 12.9% from Wisconsin (Livestock 2006). Milk generated $5.2 billion in cash receipts in 2005, and a study by J/D/G consulting attributed the dairy industry with the creation of 434,000 full time jobs and $47.4 billion of economic activity in 2004 (Dryer 2005).

Dairy Farms in California



California Energy Commission
PIER Renewables

January, 2002

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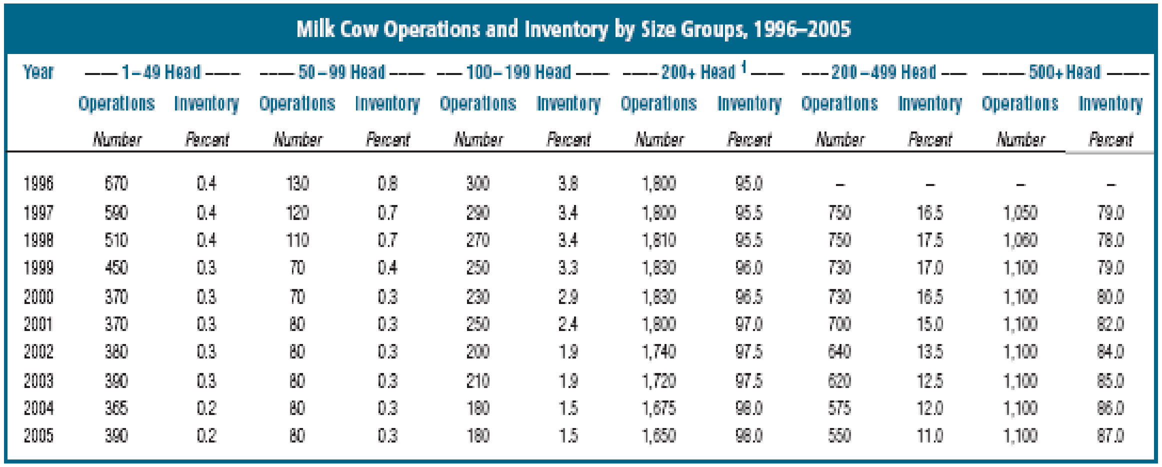
Milk production in California is concentrated primarily in the San Joaquin Valley, where the state's top five dairy counties—Tulare, Merced, Stanislaus, Kings, and Kern—are all located (Figure 1.23.1). This region characterizes the recent trend, especially prevalent in the Western dairy regions, towards fewer and larger pastureless farms that achieve higher productivity and efficiency. In 2005 the average farm size in California was 890 head per farm compared to the national average of 140 and an average of 82 for the traditional dairy state of Wisconsin. Large farms dominate overall production in California (Table 1.23.1), with the farms of greater than 500 head producing 87% of the state's total milk in 2005 (Livestock 2006).

Table 1.23.1: Milk Cow Operations and Inventory by Size Groups



Milk Cow Operations and Inventory by Size Groups, 1996–2005

Year	1–49 Head		50–99 Head		100–199 Head		200+ Head [1]		200–499 Head		500+ Head	
	Operations	Inventory	Operations	Inventory	Operations	Inventory	Operations	Inventory	Operations	Inventory	Operations	Inventory
	Number	*Percent*	*Number*	*Percent*	*Number*	*Percent*	*Number*	*Percent*	*Number*	*Percent*	*Number*	*Percent*
1996	670	0.4	130	0.8	300	3.8	1,800	95.0	–	–	–	–
1997	590	0.4	120	0.7	290	3.4	1,800	95.5	750	16.5	1,050	79.0
1998	510	0.4	110	0.7	270	3.4	1,810	95.5	750	17.5	1,060	78.0
1999	450	0.3	70	0.4	250	3.3	1,830	96.0	730	17.0	1,100	79.0
2000	370	0.3	70	0.3	230	2.9	1,830	96.5	730	16.5	1,100	80.0
2001	370	0.3	80	0.3	250	2.4	1,800	97.0	700	15.0	1,100	82.0
2002	380	0.3	80	0.3	200	1.9	1,740	97.5	640	13.5	1,100	84.0
2003	390	0.3	80	0.3	210	1.9	1,720	97.5	620	12.5	1,100	85.0
2004	365	0.2	80	0.3	180	1.5	1,675	98.0	575	12.0	1,100	86.0
2005	390	0.2	80	0.3	180	1.5	1,650	98.0	550	11.0	1,100	87.0

[1] *Starting in 1997, the 200+ Head class was broken out into 200+ Head, 200-499 Head, and 500+ Head classes.*

(Livestock 2006)

Production

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Dairy farmers produce milk, which is processed into a variety of dairy products or remains as fluid milk. Like cattle feedlots and other CAFOs, the dairy industry's primary inputs are feed, labor, and capital.

Dairy CAFOs in California include neither pasture land for grazing or cropland for growing feed and are thus reliant on purchased feed transported from distant regions like the Midwest. Traditionally, dairy cow feed includes protein sources such as: corn silage, alfalfa or grass silage, alfalfa hay, ground or high-moisture shelled corn, soybean meal, cottonseed, and perhaps commodity feeds (corn gluten, distillers grains, soybean hulls, citrus pulp, candy bars, etc.), yet also includes vitamin and mineral supplements, antibiotics and other medical additives (Feeding 2006).

Although dairy operations have become highly automated, dairying is still a highly labor intensive activity and the large capital-intensive dairies that dominate California's industry require skilled labor in order to run efficiently (Short 2004). According to a 2006 survey, hired dairy farm labor in the western US received an average hourly wage of $10.28 in 2006 in addition to commonly provided monthly or annual incentive programs. The current percentage of foreign born labor in California is 94%, with the majority originating from Mexico and Central America (Encina 2006). In 2004 17,000 people worked directly on dairy farms, 2000 of which were owner-operators (Dryer 2005).

Unlike many other mostly agricultural ventures, dairy has many capital inputs that are specific to the production of milk, giving the dairy producer very little flexibility in switching operations. "On farm refrigerated bulk milk tanks, improved milking equipment, modern and efficient milking parlors,... animal housing, and improved feed-handling and waste-handling systems are examples of technological innovations widely adopted by dairy farmers" (Blaney 2002).

Another notable production input for dairy farms is energy and fuel. A study finds that 2/3 of the 9 trillion btu's of energy used on dairy farms was petroleum based fuel with the other 1/3 being electricity (Brown 2005). Methane digesters provide a potential for on-farm generation to offset this purchased electricity.

Costs / Balance Sheet

Variable Costs make up about 82% of the total production costs, and feed costs are the largest overall costs—making up 52% of total costs and 63% of variable costs in 2006. Hay and straw, complete feed mixes, and feed grains are the largest items in this category (Monthly 2005). As such a high proportion of total costs, feed prices are a major concern of milk producers. Recently, as corn feed prices have hit their highest prices in a decade, dairies have responded by lowering their rations of corn, with some central valley producers reportedly lowering them 20-30%. “The substitute feeds are varied and include mill run, bakery waste, hay and silage” (Merlo 2007).

Locational Considerations

While the number of Dairy cows in California is currently growing, the state is seeing a slowdown in growth and the relocation of dairies—especially those in the sky-high real estate areas of Southern California—to areas outside the state. Many factors affect locational decisions. The “California Agricultural Resource Directory” cites difficulty of obtaining permits, environmental regulations, and the dairy retirement program for the recent slowdown in California's dairy growth (livestock 2006). One econometric study found “that differences in state environmental regulations may have contributed to migrations of dairy farms across regional boundaries to locations with less stringent environmental regulation.” It also found “local economic conditions such as property taxes, land values, or feed costs, socioeconomic factors such as population, poverty level, or unemployment rate, and climate considerably impact dairy location and production levels” (Isik 2004).

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Table 1.23.2: California Dairy Production Cost: 5-Year Comparison

Production Cost 5-Year Comparison [1/]	2001 Average	2002 Average	2003 Average	2004 Average	2005 Average
Number of Herds	238	215	204	196	179
1. Feed Costs					
a. Dry Roughage	$30.41	$31.72	$29.71	$30.17	$31.66
b. Wet Feed & Wet Roughage	$15.30	$15.06	$15.85	$17.64	$20.18
c. Grain	$49.49	$50.48	$51.97	$55.91	$58.53
d. Minerals & Supplements	$4.99	$5.85	$5.91	$6.47	$6.38
e. Pasture	$0.63	$0.57	$0.43	$0.42	$0.49
Total Feed Costs	$100.82	$103.68	$103.88	$110.62	$117.24
Total Feed Costs (% of total Cost)	47.7%	47.3%	48.2%	49.5%	49.1%
2. Total Labor	$23.85	$24.88	$26.10	$26.84	$27.46
Total Labor Costs (%of total cost)	11.3%	11.3%	12.1%	12.0%	11.5%
3. Herd Replacement	$29.24	$35.32	$30.56	$29.11	$32.54
Total Replacement Costs (%of total cost)	13.8%	16.1%	14.2%	13.0%	13.6%
4. Operating Costs					
a. Utilities	$4.66	$4.68	$4.56	$4.33	$4.45
b. Supplies	$7.52	$7.62	$7.60	$7.94	$8.30
c. Veterinary & Medicine (incl. rBST)	$6.78	$6.78	$6.82	$6.38	$7.37
d. Outside Services	$3.25	$3.19	$3.12	$3.16	$3.41
e. Repairs & Maintenance	$5.13	$4.61	$4.18	$4.72	$5.07
f. Bedding & Manure Haul	$1.74	$2.05	$1.64	$1.35	$1.33
g. Tractors, Trucks, Fuel & Oil	$3.10	$3.04	$3.00	$3.31	$3.52
h. Miscellaneous	$0.41	$0.36	$0.69	$1.13	$1.20
i. Interest	$7.72	$5.88	$5.65	$6.09	$6.88
j. Lease Expense	$3.06	$3.01	$2.88	$2.49	$2.98
k. Depreciation	$5.01	$5.12	$5.49	$6.39	$6.61
l. Taxes & Insurance	$1.35	$1.38	$1.42	$1.54	$1.86
Total Operating Costs	$49.73	$47.72	$47.05	$48.85	$52.99
Total Operating Costs (%of total costs)	23.5%	21.8%	21.8%	21.8%	22.2%
5. Milk Marketing Costs					
a. Hauling	$4.60	$4.66	$4.77	$4.86	$5.26
b. State Assessments	$2.32	$2.18	$2.24	$2.35	$2.35
c. Federal Assessments & Misc. Ded.	$0.97	$0.98	$0.94	$0.95	$0.95
Total Milk Marketing Costs	$7.89	$7.83	$7.96	$8.16	$8.55
Total Milk Marketing Costs (% of total costs)	3.7%	3.6%	3.7%	3.6%	3.6%
6. Total Milk Marketing Costs ($/cwt.)	$0.46	$0.45	$0.46	$0.47	$0.48
7. Total Cost ($/Cow/Month)	$211.53	$219.43	$215.55	$223.57	$238.77
8. Total Cost ($/cwt)	**$12.24**	**$12.61**	**$12.44**	**$12.75**	**$13.43**
9. Milk Production Data					
a. Adjusted Gross ($/cwt.)	$14.15	$11.13	$11.53	$14.94	$14.15
b. Milk Sold/Cow/Month (cwt.)	17.28	17.40	17.33	17.54	17.78
c. Gallons sold/Milk Cow/Day	7.72	7.76	7.70	7.76	7.87
d. Fat Test %	3.71%	3.71%	3.69%	3.70%	3.70%
e. SNF Test %	8.77%	8.77%	8.76%	8.80%	8.81%
f. Fat Sold/Milk Cow/Month (lb.)	74.98	75.40	74.25	75.09	76.05
g. SNF Sold/Milk Cow/Month (lb.)	177.11	178.08	176.36	178.71	181.27
10. Related Data					
a. Percent Dry Cows	14%	14%	14%	14%	14%
b. Yearly Cull Rate	33%	34%	36%	35%	35%
c. Avg. Value ($/Drop Bull Calf)	$79.79	$50.88	$62.20	$102.78	$135.28
d. Milk Cow Alfalfa Hay Price ($/ton)	$140.77	$143.86	$134.60	$142.87	$163.79
e. Grain, Mnrls & Splmnts ($/ton)	$141.46	$145.38	$152.71	$161.65	$163.57
f. Grain, Mnrls. & Splmnts. (lbs/mc/day)	29.12	29.17	28.46	28.69	29.59
g. Milkers ($/hr with benefits & taxes)	$11.93	$12.54	$13.28	$13.19	$13.33
h. Total Feed Costs ($/Milk Cow/Day)	$3.62	$3.70	$3.72	$3.92	$4.15
i. Milk Cow Feed Cost ($/cwt.)	$5.45	$5.55	$5.61	$5.87	$6.13
j. Milk Cows (average herd size)	751	780	884	817	866
k.Total Cows (average herd size)	827	865	963	946	1002
l. Mailbox Price ($/cwt.)	$13.89	$10.99	$11.49	$14.79	$13.95

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In another study, a survey of dairy farmers finds that out of 110 listed factors, farmers in the Southwest consider the ten most important to be:

1. Average mailbox price of milk
2. Availability of adequate fresh water supplies
3. Quality of fresh water supply
4. Cost of feed
5. Cost of hauling milk
6. State and local income tax rate
7. Availability of land on which to incorporate animal waste
8. Proximity to milk processors and handlers
9. Proximity to large fluid milk markets
10. Complexity of state and local laws governing waste handling and odor management

Source: Stirm 2003

Emissions

Although methane is released in much lower quantities than CO2, it is 21X as potent and is therefore a major source of California's total GHG emissions. Methane is also the main component of natural gas, making energy generation a major focus of its mitigation strategy. In 2002 methane made up a 6.4% share of California's GHGs, with landfills (2.0%), enteric fermentation (1.7%), and manure (1.4%) being its three largest contributers (Bemis 2005).

Enteric Fermentation

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Enteric methane is produced in the stomachs of ruminant animal—such as cattle, sheep, and goats—during digestion. “Plant material consumed by ruminant livestock is fermented by approximately 200 species of microbes in the rumen, the first of a four-part stomach,” producing methane as a byproduct (Enteric 1999). This methane is mostly belched by the animal throughout the day, which makes capture and utilization of the gas unrealistic. Instead, the mitigation of enteric methane will take place by reducing emissions through a number of possible strategies. Since large production of enteric methane is a signal of an inefficient use of energy by the cow, its reduction can be a source of increased milk productivity as well.

An emissions rate of around 290gCH4/cow*day has been estimated from several studies, although this can vary with many different factors (McGinn 2006).

Currently a great deal of research is being done internationally to find ways to reduce the amount of methane produced per cow while another approach is to increase the productivity of dairy cows, recognizing that lowering methane/cwt is the ultimate goal. A study by Johnson et al. finds that for every 10% increase in milk/cow resulted in a 5-6% decrease in GHG/milk (McGinn 2006). Approaches that include diet and feed composition include:

1. **Intensification**

   Feeding livestock high digestibility feed such as grain or high quality pasture increases milk production per cow and reduces methane emissions per unit of production (i.e. more efficient production).

2. **Dietary Fats**

Additions of unsaturated fatty acids to ruminant diets may reduce methane by up to 40% i.e. 7% linseed oil may result in a 37 % reduction in methane emission.

3. **Carbohydrate type**

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The type of carbohydrate fermented in the rumen influences methane production. Dairy production systems based on temperate perennial rye grass/white clovers pasture will produce less methane than dairy cows fed sub-tropical pastures like Setaria or Kikuyu. The fermentation of brewers grain and distillery products containing relatively available fiber results in methane production 33% to 50% of that seen with common feedstuffs of comparable digestibility.

4. Forage Processing

Grinding and pelleting of forages can markedly decrease methane production. At high intakes, methane loss/unit of diet can be reduced 20-40 %.

Other approaches focus on modifying the makeup of the animal's digestive system, such as:

1. Defaunation

In the absence of protozoa, rumen methane emissions are reduced by an average of 20 %, and it is likely that cows will produce up to 1 to 1.5 litres more milk per day at peak lactation. As animals refaunate rapidly by grazing, only dairy production systems offer the possibility of administering defaunating agents regularly during milking.

2. Acetogens

Acetogens are rumen microbes that convert carbon dioxide (CO2) and hydrogen gas (H2) to acetate, an energy source for the cow, while methanogens form methane, a waste product, from the same basic compounds. Research is underway in New Zealand to investigate the possibility of replacing methanogenic microbes with acetogenic microbes.

3. Vaccination

Methanogens are antigenetically distinct from other organisms in the rumen, allowing a vaccination approach to the reduction of methane production by rumen methanogens.

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Source: Dairy Greenhouse Framework, 2006

Manure Management

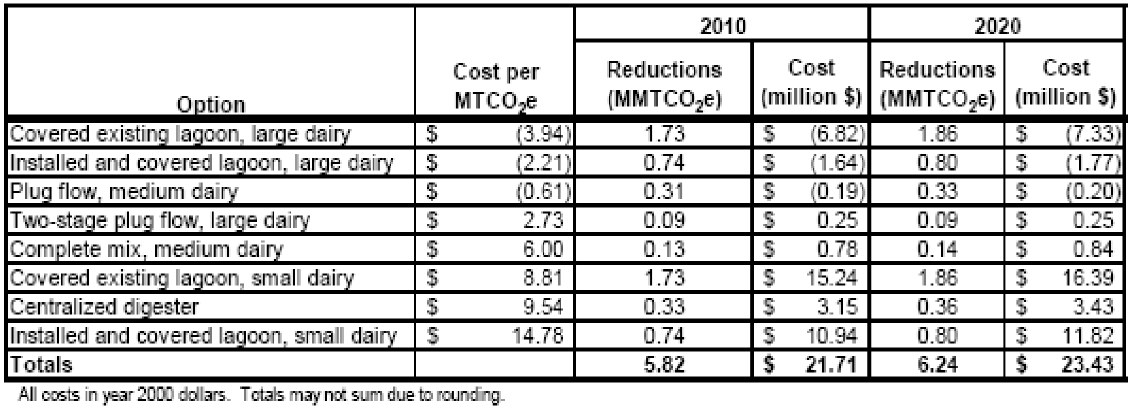
Another source of dairy methane emissions results from the farms' manure management practices. When stored in oxygen poor environments, manure is broken down anaerobically and methane is produced. Although there are several ways to dispose of manure without producing large amounts of methane—such as spreading over a pasture—CAFOs generally do not have the land available for such disposal and instead practice wet storage systems, like liquid/slurry and anaerobic lagoons, that produce large amounts of methane. Currently in California, 57% of manure is managed by anaerobic lagoons, 21% by liquid slurry, 11% by daily spread, 9% by solid storage, and 1% by pasture (Emission 2006).

The reduction strategy for methane produced by manure disposal/storage focuses on the installation of methane or “biogas” digesters. A digester captures the methane and either burns it off through a flare or uses it to generate electricity. The most common systems are covered lagoon digesters, complete mix digesters, plug flow digesters, and centralized digesters.

In a report supported by the CEC PIER program, ICF Consulting produced estimates of each system's overall mitigation potential based on feasibility and costs as well as cost estimates for various digester options (Table 1.23.3). They estimate reduction costs per MTCO2e as low as $0.54 for centralized digesters, and $0.61 for plug flow on medium sized dairies, and as high as $8.81 and $14.78 for covered lagoon systems on dairies with and without preexisting lagoons. Table 1.23.3 on also provides capital and operating costs for these systems based on ongoing projects in California (e.g. Straus Dairy, Joseph Gallo Dairy, CalPoly Diary) (Emission 2006).

Since these systems enable farmers to replace electricity purchased from utilities with their own electricity production, the cost of these systems decrease with higher utility electricity rates. If policies are enacted that lead to an increased electricity rates, a possibility that seems rather likely, these systems will become increasingly attractive (Table 1.23.3).

Table 1.23.3: Digester Reductions and Costs



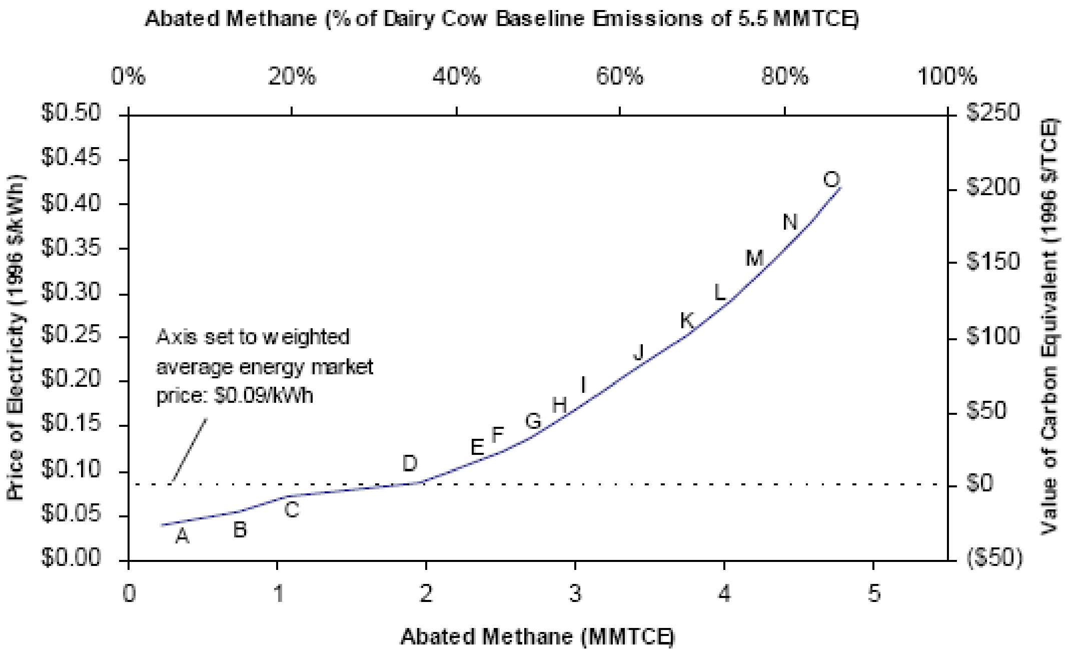
Option	Cost per MTCO$_2$e	2010		2020	
		Reductions (MMTCO$_2$e)	Cost (million $)	Reductions (MMTCO$_2$e)	Cost (million $)
Covered existing lagoon, large dairy	$ (3.94)	1.73	$ (6.82)	1.86	$ (7.33)
Installed and covered lagoon, large dairy	$ (2.21)	0.74	$ (1.64)	0.80	$ (1.77)
Plug flow, medium dairy	$ (0.61)	0.31	$ (0.19)	0.33	$ (0.20)
Two-stage plug flow, large dairy	$ 2.73	0.09	$ 0.25	0.09	$ 0.25
Complete mix, medium dairy	$ 6.00	0.13	$ 0.78	0.14	$ 0.84
Covered existing lagoon, small dairy	$ 8.81	1.73	$ 15.24	1.86	$ 16.39
Centralized digester	$ 9.54	0.33	$ 3.15	0.36	$ 3.43
Installed and covered lagoon, small dairy	$ 14.78	0.74	$ 10.94	0.80	$ 11.82
Totals		**5.82**	**$ 21.71**	**6.24**	**$ 23.43**

All costs in year 2000 dollars. Totals may not sum due to rounding.

(Ogonowski 2005)

Figure 1.23.2: Marginal Abatement Curve for Methane Emissions from Dairy Cow Manure Management in 2010

Exhibit 5-9: Marginal Abatement Curve for Methane Emissions from Dairy Cow Manure Management in 2010



(Manure Management 1999)

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California has already enacted three programs that encourage the installation of digester projects, the first two providing partial funding and the third assuring proper recognition from electrical utilities.

1. The Dairy Power Production Program (DPPP) was established in 2001 under SB 5X
   a) Project developers can choose between buy down grants covering up to 50% of the total capital costs of the system, or incentive payments based on a cost of 5.7 cents per kWh.
   b) About 60 out of 2,300 farms applied. 14 projects (~3.5 MW capacity) were approved for grants totaling $5.8 million. The program is now closed to new applications.
2. Self-Generation Incentive Program (SGIP)
   a) The SGIP offers financial incentives (in the form of payments for a portion of capital costs) to customers who install certain types of distributed generation facilities.
   b) Maximum generator system size allowed is 5 MW, with the total incentive payment limited to 1 MW.
   c) As of January 2005, there were 11 dairy farm digester projects in the program totaling ~2.3 MW. For dairy farms, incentive payments have ranged from $1 to $9 per watt.
   d) The SGIP has been extended through 2007.
3. A pilot program for net metering for digester projects was established under Assembly Bill 2228 in 2002
   a) Law requires the state’s three largest investor-owned utilities (PG&E, SCE, and SDG&E) to offer net metering to new dairy farms that install digesters with a capacity of 1 MW or less.
   b) Each utility is required to offer net metering only up to a total of 5 MW, for an aggregate total of up to 15 MW.
   c) Assembly Bill 728 would extend the existing program indefinitely; remove the 5 MW and 15 MW limits; and increase the capacity limit of eligible digesters to 10 MW. The bill’s prospects are unclear.

Source: Ogonowski 2005

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These programs are responsible for most of the current digesters that have thus been installed in California, and will likely remain part of future policy. The net metering program is crucial in realizing the potential electricity production that these systems can provide. A recent CEC sponsored survey project confirms this importance and suggests that ultilities should provide even more favorable agreements with farmers who install digester systems. The survey found that many of the US dairy farmers who have installed these systems had trouble negotiating fair terms with their local utilities. Along with receiving much lower rates for their electricity than they paid for purchased electricity—which net metering can avoid—"they were dismayed by the high cost of electrical upgrades that were often required in order to interconnect with the electrical grid.... [This]infrastructure...was not located on their land and would become the property of the utility" (Tikalski 2007).

Concluding Remarks

Policies designed to mitigate methane produced from dairy and livestock will have to work around the difficulty of monitoring both enteric and manure sources. A possible solution for enteric methane could include mandates on the composition of or financial help for other of the dietary solutions. The current trend of higher cow productivity aids reduction, so this trend should be encouraged, or at least not discouraged. For manure management, fairly accurate emission estimates could be feasible, possibly allowing it to be worked into a cap and trade scheme. Continuing California's current digester programs will aid in mitigation, and furthering the cooperation that they have begun between utilities and dairies should be a very important piece of the final policy.

1.23.2 Scenario Description

Anaerobic decomposition of animal manure produces significant amounts of methane, a non-CO2 GHG with relatively high GWP. In highly concentrated livestock production systems, this gas can be captured with digester technologies and dissipated by burning in flares or power generation. The objective of this scenario is to assess the economic effects of promoting such capture and dissipation strategies.

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For Manure Management, eight measures in the dairy sector are included:

1. Covered Lagoon, not Including Lagoon Cost – Large Dairy
2. Covered Lagoon, Including Lagoon Cost – Large Dairy
3. Plug Flow Digester – Medium Dairy
4. 2-Stage Plug Flow Digester – Large Dairy
5. Complete Mix Digester – Medium Dairy
6. Covered Lagoon, not Including Lagoon Cost – Small Dairy
7. Centralized Digester
8. Covered Lagoon, Including Lagoon Cost – Large Dairy

For the moderate scenario, we consider only the first measure, while all are included in the ambitious scenario below.

1.23.3 Data Sources

The ICF (2005a) report provides our baseline data for this scenario, with comparison reference to the international MAC data, and we calibrate abatement using the MAC framework.[44] Methane emissions are measured in CO2 equivalents, the demand for abatement technology is directed at the construction sector, captured gas and is consumed in the dairy sector (resulting in savings on electricity expenditures), self-generated electricity is metered to utilities, and digestate by-products are sold to the agricultural sector.

Figure 1.23.3: Methane Cost Function for 2010

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[44] Compare also EPA (1999).

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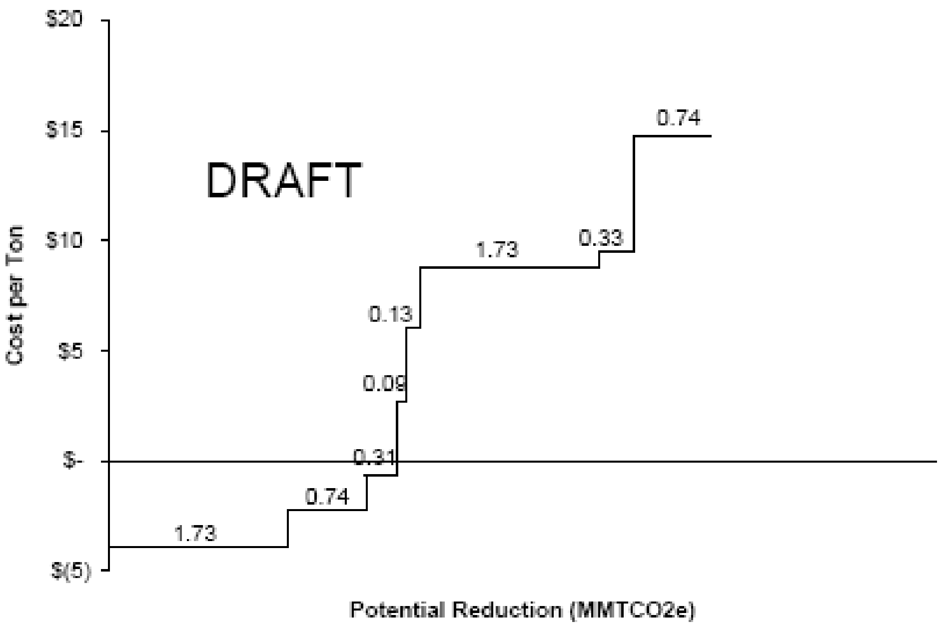

(Ogonowski 2005)

1.23.4 Modeling Approach

Modeling specification and calibration are analogous to Landfill management above, with the single exception of an additional revenue stream. This is the sale of processed manure digestate to the agriculture sector for use as fertilizer. Otherwise, the simulation proceeds as in Landfill, with a single consolidated mitigation scenario and corresponding assumptions about industry homogeneity.

1.24 Semiconductor Industry Targets

1.24.1 Sector Analysis

Through the release of a relatively small amount of certain green house gasses, or GHG's, the impact on the environment can be equal to vast amounts of carbon dioxide. One of the most robust greenhouse gases are perfluorocarbons, which are colorless, odorless, and unreactive man made chemicals that do not seem to do much regional harm, but have great potential to contribute to global warming. Unlike CO_2 which can be sequestered, perfluorocarbons have extremely long atmospheric lifetimes of 10,000 to 50,000 years (Aslam, et. al 2003). Between 1978 to 1997 the most abundant perfluorocarbons were CF4, C2F6, and C3F8. C2F6 and C3F8 are present at only 2.9 and .2 pptv (parts per trillion by volume), respectively. CF4 is present at 74 pptv with 40pptv from natural emissions, 33 pptv from aluminum manufacturing, and 1 pptv from the semiconductor industry. Though these initial measurements seem small the CO_2 global warming potential is great. These emissions have been gradually decreasing largely because of major reductions in emissions within the aluminum industry (Marks 2003), but increases in production with the semiconductor industry have offset some of these gains (Aslam, et. al.2003). This shows how the aluminum industry may contribute significantly to PFC emissions, but this does not mean the semiconductor industry should not be regulated since the contribution from the semiconductor industry is significant and PFC concentrations in the atmosphere will constantly accumulate in the future.

The histories of tetrafluoromethane (CF4) and hexafluoroethane (C2F6) have been reconstructed based on firn air measurements of compressed ice from both hemispheres (Worton 2007, Butler 2001). The research has shown that atmospheric ratios of both CF4 and C2F6 have increased during the 20th century by factors of 2 and 10, respectively. Though it seems to closely coincide with aluminum production, a marked decrease in the rate of specifically CF4 production in the 1990's confirms aluminum industry reports of reduced CF4 emissions while highlighting the significant impact C2F6 which is probably caused by the semiconductor industry. Though atmospheric growth rates of PFCs may continue to decrease due to increased public awareness and agreements like the Kyoto Protocol, the overall concentration of PFCs in the atmosphere will continue to increase due the to long lifespan of PFCs (Worton 2007).

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Overview of the U.S. Semiconductor Industry

The U.S. semiconductor industry had $115 Billion in sales in 2006 and controls a 46 percent market share of a $248 Billion market. 77 percent of sales are outside the U.S. market and R&D investment is high, averaging about 16% of sales (SIA 2007). The total number of firms was 6047 in the 2004 reporting period and 19 of these firms have over 50 percent of the market in net sales (Troy 2006) and continues to be a growing industry as demand for electronics increases worldwide (Malonis 2001).

Inputs, Outputs and the Role of PFCs in Production

Significant emissions

Currently the manufacturing of semiconductors require high global warming potential (GWP) gases that includes not only perfluorocarbons like CF4, C2F6, C3F8, but also other compounds like trifluoromethane (CHF_3), nitrogen trifluoride (NF_3), and sulfur hexafluoride (SF6). The weighted industry average impact of these gases upon global warming is 9000 times the GWP of CO2. (Exhibit 6.1)[i]

PFCs are both a production externality and an essential production input because they are extremely effective in plasma etching. They create intricate circuitry by shooting plasma streams to make connections that are only nanometers thick. This technology is extremely precise and must use gases like PFCs to do plasma etchings and cleaning chemical vapor deposition (CVD) tool chambers. Current liquid cleaning technology is not very developed and too expensive to use and though substitutes are available the use of PFCs in production is critical to remain competitive in an international market (EPA 2007).

It has been assumed that PFCs were largely consumed during chip manufacturing, but now it is accepted that under normal operation from 10 to 80 percent of PFCs go through manufacturing tool chambers unreacted and into the air (EPA 2007). These emissions vary according to gas used, equipment, type of product, and abatement programs in place.

The Semiconductor Industry and the SIA

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The best way to analyze and collaborate with the semiconductor industry in the United States is through the Semiconductor Industry Association. Since the SIA represents 85% of the U.S. semiconductor industry (SIA 2007) and only a handful of firms control most of semiconductor revenues (Troy 2006), it would be wise to work together with this one organization than individually regulate thousands of individual firms that all have different PFC outputs according to product as well as constantly changing technologies. Therefore, in 1996 the EPA launched the *PFC Emission Reduction Partnership for the Semiconductor Industry* in an effort to reduce emissions through a the voluntary collaboration between the EPA and the SIA. The manufacturers involved produced emissions equivalent to 4.6 million metric tons of carbon dioxide in 2002 which is a 37% improvement since 1999 (EPA 2007). The semiconductor industry is currently working to reduce emissions of PFCs proactively without government regulations. Since the big players in the semiconductor industry, such as AMD and Intel who control most of the market share for microprocessors (Malonis 2001), are both part of the SIA, this report will not focus on the reaction of individual companies to GHG issues, but will mainly cover the relation of the semiconductor industry as a whole with regard to GHG emissions.

Technology Costs and PFC Reduction Options

Abatement and Mitigation Possibilities

A large portion of chip manufacturing is done in “clean rooms” that are usually associated with the semiconductor industry. This is to prevent dust from interfering with precise etching technology and usually results in enormous costs for new fabrication facilities (fabs) upwards of $2 billion (O Huallachain 1997). These closed system fabs greatly increase the fixed costs involved for producing the latest chip, which can be a hindrance to this high tech industry with a high turnover rate. However these two hindrances become benefits in relation to emissions reductions because high turnover means new pollution policies can be tested and observed. Also, closed system fabs enable extremely efficient abatement and recycling technologies that are more than 90% efficient.

There are four major methods for reducing PFC emissions:

Process improvements and source reduction

Process optimization can be achieved by using point of use detectors and adjusting inputs to find the optimal level of PFCs to reduce excess use. One example is the optimization using C2F6 in the chamber cleaning processes which can reduce consumption by up to 50% and abate up to 85% of emissions (EPA 2001).

Alternative chemicals

There are some substitutes for the currently most popular high GWP gases with other fluorocarbons that perform comparably but have much less GWP, quicker atmospheric lifetimes, and/or have lower destruction costs. An example of this is by replacing C3F8 currently used in the etching process with C5F8. Although they both have a GWP around 100, C5F8 has a lifetime in the atmosphere of only one year compared to the 3200 year lifespan of C4F8.

Capture and beneficial reuse

There is capture and reuse technology that is not yet widely adopted due to high costs, but is effective in removing PFCs from the whole fabrication facility. This technology also has the ability to separate unreacted PFCs for further processing. Current systems remove about 90 percent of emissions with even higher efficiencies for C2F6, CF4, and SF6. Destruction costs of collected gases are estimated to be $3/kilogram and reprocessing costs are estimated to be so much more expensive that it is not feasible unless the fab emits high levels of PFCs (EPA 2001).

Destruction technologies.

The most efficient, but also one of the most expensive ways to reduce emissions is to use one of three available destruction technologies:

Point-of-Use Plasma Abatement (Litmas) technology. This technology is used in conjunction with the etch tool. (Figure 2)[ii] It dissociates PFC molecules which later reactive with additive gases that make the residue heavier. Then wet scrubbers remove the remaining molecules. (SEMATECH, 1998)

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Thermal Destruction This technology may be useful because it doesn't affect the manufacturing process and can abate emissions by over 95%. A downside is that this process uses combustion devices that require fuel and produce significant amount of wastewater.

Catalytic Decomposition System (Hitachi). This technology can reduce emissions by 98% by a method similar to Point-of-Use Abatement but require a minimum flow of PFCs and is very expensive.

Cost Analysis for Abatement and Mitigation Options

Of the available options, the alternative chemicals options seems to be most economically viable. IBM, a major player within the semi-conductor industry, has adopted the NF3 alternative chemical approach that replaced C2F6, reducing PFC emissions by 95% and avoiding $3 million in capital and $3 million in annual operating costs to a comparable recycling program (IBM 2007). The breakeven cost of $/ Tons of Carbon Equivalent is cheapest for the alternative chemicals option at $17.51 and thermal destruction is the most expensive at $138.61 as seen in the figure (Exhibit 6.4). This shows increasing marginal costs across abatement technologies. Though thermal destruction technology has an efficiency rate of 97% it would not be feasible unless there is 17 Million Metric Tons of Carbon Equivalent (MMTCE) in emissions. For comparison, the 2010 baseline emissions prediction for "business as usual" semiconductor manufacturing is 17.5 MMTCE even though current use is a third that amount.

Predictions in Technology Adoption

The two most likely adoption choices for semiconductor industries is alternative chemicals and plasma abatement technology. 55% of the semiconductor manufacturing industry is expected to adopt plasma abatement technology while 45% of the industry is expected to adopt two different alternative chemical technologies (Exhibit 6.5). This is probably due to the high costs of alternative technologies. Capture and recycling technology cannot feasibly be used in conjunction with other technologies because the cost of extracting unreacted PFCs and reusing them are too high if there is too low of a PFC concentration in exhaust streams. Though the marginal cost for this technology is high, it may become popular if the value of PFCs increase due to some future technology.

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Total GHG Emission Reductions Go Beyond PFC Emissions

The impact of the semiconductor industry on global warming is not limited to only PFC emissions. An manufacturer can have zero PFC emissions but use so much electricity to run abatement devices that it would cause much more environmental impact. According to the Green House Gas Protocol, there are three scopes that effectively account for the total environmental impact of an industry, which are direct GHG emissions, electricity indirect GHG emissions, and other indirect GHG emissions (WRI 2007).

Direct GHG Emissions

Some other GHG emissions other than PFCs could include fugitive gas leaks, and oxidation of organic waste.

Electricity Indirect GHG Emissions

The electricity involved in production may increase GHG emissions depending on the power plants in the area.

Other Indirect GHG Emissions

The production of specialized imported materials produces GHGs and the consumption of wastes as well. Production of purchased material and infrastructure would also contribute GHGs. The outsourced disposal of returned gases would be another source of GHGs as well as fugitive emissions of CO_2 and CH_4 in landfills. Due to the fast turnaround of the semiconductor industry, E-junk is accumulating at an ever increasing pace. This junk can in turn release fugitive emissions in landfills.

Emissions Reduction Potential in Products

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Not only do total emissions need to be accounted for, but also emissions reduction from more efficient technology. Intel boasts of a chip technology that may reduce energy usage of computers by 71% (Intel.com). The EPA has estimated that between 2002-2008 this new technology would prevent 159 MTTC in emissions. This averages to about 13.25 MMTC per year and combined with other advances in technology, could prevent CO2 emissions that well exceed the CO2 equivalent impact of PFCs.

Prognosis for the Future

The semiconductor manufacturing industry is a field that was growing at a healthy 15% per year in the 1990's (Malonis 2001) and still continues to grow at a healthy pace. One top of this, the industry continues to produce chips that are increasingly more complex and bigger in wafer size.

In terms of emissions behavior, the industry seems to be headed toward self-imposed reduction guidelines while working closely with the EPA. One reason for the semiconductor industry's proactive response to emissions could be because of public awareness of GHGs. The high visibility and the wide consumer base of the semiconductor industry may have prompted the industry to lower emissions. Other GHG producers like concrete production are not as visible and directly connected with the general public so may have less public pressure than the semiconductor industry to reduce GHGs.

International competition in the semiconductor industry is fierce. Asian semiconductor companies are increasingly gaining worldwide market share (Figure 2). This very well may be due to cheap skilled labor and more lax environmental and safety regulations in Asian fabrication facilities (Tenenbaum 2003). A 2002 report also revealed that demand is shifting toward Asian nations. Though 32.4% of shipments were directed at the Americas, Japan and other Asian nations had 20.4 and 25.9% distribution rate, respectively (Malonis 2001). Clearly this demand will continue to increase in the future with the fast growing populations in China. Demand for chips in China is growing at 29% per year and is providing a rebate if products are produced in China (Tenenbaum 2003). It is incentive like these that is increasing the outsourced production of semiconductors for U.S. companies.

Prognosis for Policy Response and Conclusion

Though the semiconductor manufacturing industry contributes a considerable portion of high GWP gases today, there are still many other industries that contribute much more GHGs, so relative costs must be taken into account in policy analysis. Reductions in emissions in the semiconductor industry is one of the simplest to do because of closed system fabs, but also one of the most expensive with an average of $20/MTTC with current mitigation options and increasing marginal costs of abatement. (Figure 7)

Assuming the industry refuses to change emissions habits and the government chooses to regulate, reduction in emissions could be achieved through quotas, taxes or subsidies. Enacting strict quotas may be too restricting because the industry is still expanding and this could cause industry flight. This is because though the fixed costs for fabrication plants are extremely expensive, cheaper skilled labor, looser regulations, and lower taxes abroad is causing firms to produce oversees even now (Tenenbaum 2003). Reductions in emissions as a percentage of production may be more feasible because it would encourage new technology development and creative means of PFC reduction while remaining competitive internationally. The downside to this is that as the semiconductor industry continues to expand, net emissions of PFCs may actually increase even though efficiency rises. The option that is most favorable for the industry would be subsidies that would encourage reductions but may encourage slippage in light of current efficiency gains and emissions reduction efforts.

However, taking into account the current behavior of the SIA and their agreement to voluntarily reduce emissions by 2010, the current voluntary collaboration between the EPA and the semiconductor industry may remain as the best decision. Continued public awareness about the effects of PFCs would prompt the visible chip manufacturers to reach reduction goals and voluntarily invest in abatement technology.

Furthermore, seeing the high price per MMTC of reduction in comparison to other sources of GHGs indicates that the other sources should reduce emissions first until the increasing marginal cost of continued reduction necessitates the semiconductor industry reduces emissions more than it already is. A loosely regulated semiconductor industry would resist the current trend of outsourcing production and allows the

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industry to remain competitive. A competitive chip industry may also lead to more efficient chip design which would reduce GHG emissions when the end user uses the product.

1.24.2 Scenario Description:

This scenario covers the main mitigation measures to achieve voluntary targets negotiated between U.S. EPA and Semiconductor Industry Association.

1.24.3 Modeling Approach:

In each of the scenarios, bottom-up cost estimates were ascribed directly to the semi-conductor sector via intermediate flow adjustments in the input-output component of the new California SAM. Five reduction measures were examined:

1. Plasma Abatement
2. Remote Clean
3. Catalytic Abatement
4. Capture/Recovery using Membranes
5. Thermal Destruction

For the moderate scenario, we consider only the first two measures. All five are included in the ambitious scenario.

1.24.4 Data Sources and Description:

The ICF (2005a) report provides our baseline data for this scenario. This report notes that US semiconductor manufacturers (through an MOU between the Semiconductor Industry Association and the EPA) have pledged to reduce PCF emissions to 10% below 1995 levels by 2010. That would entail reducing emissions to 0.72 MMTCO2. Assuming that those emissions are held constant to 2020 means reducing emissions by 78% and 91% compared to ICF’s 2010 and 2020 baseline projections.

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For BEAR, this would mean that for 2010, the first three measures need to be calibrated into the Baseline and, for 2020 all semiconductor measures will be considered baseline. Increased costs for PFC abatement remain within the semiconductor manufacturing industry.

1.25 Landfill Management

1.25.1 Sector Analysis

Methane accounts for slightly over 6% of California's total climate change emissions taking into account both quantity produced and global warming potential (21xCo2) (California Climate… A, 2006). Solid waste landfills are the principal source of these emissions, accounting for about 25% of the total(Basic…Program). Landfill's offer not only the greatest opportunity for reducing methane emissions, but additionally could provide the least cost venue in which to do so, one in which many methane emitters might achieve net savings (Choate et al, 2005).

Because of these characteristics, landfills are of special significance to California's fight against climate change, and are considered in the Cal Climate Action Team's and Air Resources Board's earliest reports that elucidate measures to reduce climate change emissions (Air… Agency, 2007; California Climate…A, 2006).

With this in mind, this report (segment) will summarize key features of the landfill industry and its environment, with the ultimate intent of contextualizing and analyzing the impact of regulation upon the California landfill industry's economy. Still, one cannot explore the significance of such regulation, which will in some way promote investments in methane capture or use equipment, for California landfills without first recognizing their place in the municipal solid waste (MSW) industry. Treating landfill as an independent unit of analysis neglects some of its most essential features, and leads to inappropriate conclusions regarding the industry's response to regulation. Therefore, this investigation and analysis will proceed with a focus on landfill in the context of Solid Waste Management (SWM), which includes waste collection and related activities in addition to waste disposal (See Figure 1.25.6).

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Understanding the Landfill Industry and its Market: A Framework for Analysis

Industry Overview

Municipal solid waste or solid waste consists of household and commercial garbage (Solid…Landfill). Organic materials in MSW Landfills decompose and produce methane gas, which may be harnessed to generate electricity. MSW landfills (hereafter referred to as landfills) are distinct from hazardous waste landfills, which mostly collect dangerous commercial and industrial wastes. Hazardous waste landfills are not considered for regulation in the Cal Climate Action Team's "Early Action Measures to Mitigate Climate Change in California," and are therefore not considered in this report (California Climate…B, 2007).

As noted, the SWM industry can be divided into the collection and disposal industries. The largest companies own collection, transfer facilities (transfer facilities collect and distribute solid waste, typically to remote locations), and disposal facilities. For instance, SWM's largest company, Waste Management Inc., operates around 430 collection outfits, 365 transfer stations, 290 active landfill disposal sites, 15 waste-to-energy plants, 140 recycling plants and 85 landfill-to-gas projects (Aseltine, McRea, Modi, Shukla, Sullivan, 2006). Because landfill is most frequently provided in conjunction with to a host of other waste services, landfill can be thought of as simply an input into the production of waste services, reflecting the derived demand of the consumers who pay for the removal of their waste.

Despite such vertical integration, the US MSW industry is traditionally thought of as 'fragmented', served by local or national, private, government or quasi-governmental entities, under various competitive and institutional conditions. Since the 1980's, the number of active landfills has dropped precipitously due to local opposition to landfills, increased production costs from regulation, and saturation of existing landfills. Between 1991 and 2004 the number of landfills fell by half nationally, to around 3000, while the average disposal volume of US landfills tripled (Standard and Poor's, 2006). This was a function of both larger, newer facilities (where increased investment lead to greater economies of scale) replacing smaller, older ones, and advances in technology that dramatically increased the amount of waste that can be disposed in landfills. It also resulted in the irony of overproduction (excess capacity) under monopolistic conditions. Bioreactor technology can

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increase airspace by 10-15% by rapidly breaking down organic waste, and waste can also be packed more densely today than in the past (Standard and Poor's, 2006).

Waste production frequently mirrors growth in GDP (projected at 2.5% in 2007 by S&P) and, locally, housing markets, as construction industries can contribute a substantial percent of total waste production. Waste production is the most proximate cause of growth in the waste services and landfill industry, and has increased a modest 2% per year, with landfills projected to grow at .6% per year nationally until 2010 (Encyclopedia… Industries, 2005; Standard and Poor's, 2006). In 2005, total waste generation was estimated at 245.7 million tons (Basic…MSW). Over the last decade, the percentage of this waste disposed in landfills decreased from roughly 85% in 1989 to just over 60% in 1997, associated mostly with a coincident an increase in recycling from 10-30% (Kinnaman and Fullerton, 1999).

According to estimates from 2001, total revenue of the solid waste industry, net of intra-industry payments, was $43.3 billion with near 76 percent generated by the private sector (Beck, 2001). It employed approximately 367,800 people, with total industry compensation, including benefits, estimated at $10.0 billion. SWM directly accounts for about one-half of one percent of US GDP, and, including all direct and indirect effects of industry activities, contributes just over one percent of U.S. GDP. Using multipliers of $1.23 in additional revenue per solid waste revenue dollar and 1.58 estimated outside jobs generated per solid waste job, solid waste generates $96 billion revenue and 948,000 jobs, as well as contributing "a total of $14.1 billion in direct, indirect, and induced taxes to federal, state, and local governments" (Beck, 2001).

Waste Management Inc., the industries largest firm, had $822 million in profit on $11.1 billion in revenue. Allied waste industries had profit of $215 million on revenues of $5.5 billion in 2002. (Encyclopedia… Industries, 2005; Standard and Poor's, 2006)

The Market: Demand, Supply, and Competition

Demand

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Waste production is an undesirable product of consumption decisions, and the demand for waste services derives from the desire that this waste be removed in a legal manner (Directorate… Development, 2000). If the demand for landfill is understood to be the demand for an input into the production of waste service, a derived demand, the elasticity of demand for landfill may be approximated from knowledge of the elasticity of demand for the final product, waste services, and the availability of substitute inputs for landfill in the production of waste services. Elasticity of consumer demand for waste services is a function of the willingness to produce less trash (consume fewer products that generate trash) or to undertake self handling, such as burning refuse. Since consumers are rather unwilling to commit to either of these, it is typically estimated to be very low.

As an input in the production process, landfill's primary substitutes are commercial incinerators and recycling. These must have lower tipping fees (fee's paid for waste disposal or transfer) than landfill to incentivize collectors to use them. In the case of incineration, high capital costs mean that incinerators rely on large flows of waste to achieve the low average costs which make them profitable. In the US, landfill is currently far too cheap for incinerators to achieve the economies of scale they would need to become commercially viable. Additionally, the fly ash which incinerators produce is considered a hazardous waste, further increasing incineration costs. Even though many European countries incinerate, private and full external costs are estimated to exceed those associated with landfill disposal in most European countries (Kinnaman and Fullerton, 1999). Likewise, though recycling is becoming increasingly important for the future viability of SWM firms, it is currently far less cost effective than landfilling from a firm's point of view. Tipping fees for recycling are $100 per ton, versus $35 per ton for landfilling, and revenues that can be garnered by reselling recycled materials do not compensate for this differential. Not only is consumer demand for waste services inelastic then, but there are few production inputs that could substitute for landfill.

The effect of price increases upon waste generation therefore appears to be small. Fullerton and Kinnaman (1997) find that a 10% increase in price cuts waste by only 0.3 percent. Illegal dumping may account for one-third of the reduction (Directorate… Development, 2000).

Supply: Costs, Revenues, and Competition

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As mentioned, the supply of waste management services is fragmented, with various types of ownership and levels of competition existing within diverse institutional/legal environments. In general though, private firms are far larger and intake more waste than public ones, and are likely to operate in more profitable urban regions (Personal...Management, 2007). Additionally, the proportion of the SWM industry privately owned is increasing rapidly, as is industry consolidation (Segal and Moore, 2005; Personal… Management, 2007).

Currently, four leading companies (all publicly traded) control 40% of the US Solid Waste market, handle more than 50% of the solid waste generated, and account for nearly 70% of remaining US landfill capacity (Aseltine, McRea, Modi, Shukla, Sullivan, 2006; Standard and Poor’s, 2006). With nearly 4000 small SWM firms having revenues of 2 million or less that remain for acquisition, S & P (2006) expects the three largest US MSW companies to expand.

1.25.1.1.1.1.1 Costs

Major costs in collection include tipping fees, fuel, equipment, type, volume or weight of waste, frequency of collection, distance to disposal facility, and labor (Standard and Poor’s, 2006). “Depending on local conditions, disposal costs may range between 20 and 50 percent of the contractor's total cost of service delivery”(Scarlett and Sloan, 1996). Hedging fuel prices lower costs, and companies will often contract for up to a year of gasoline.

Costs in landfill includes landfill space, packing and disposal equipment including compactors and landfill liners, other capital necessary to comply with environmental regulations, and the volume and weight of MSW (Standard and Poor’s, 2006). These costs include landfill liners at between $100,000 to $300,000 per acre; leachate treatment and disposal at between $1 million to $2.5 million as determined by applicable standards; groundwater monitoring with annual operating costs in the $50,000 to $90,000 range; methane control costs such as capital costs for systems ranging from $500,000 to $2 million; annual operating costs ranging from $100,000 to $200,000; and finally postclosure funding, total costs of which are in the range of $10 million to $12 million (Segal and Moore, 2000). Tipping fees must reflect all these costs for a landfill to be profitable. A typical balance sheet for a SWM firm is shown in Table 1.25.1.

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Table 1.25.1: Sample Landfill Cost Worksheet

Sample Landfill-Cost Worksheet

The "Typical Costs" shown are based on the following assumptions:

- Population Served - 200,000
- Waste Stream - 550 tons per day
- Land Area - 150 acres
- Landfill - 100 acres
- Landfill capacity - 6.45 million cubic yards
- Landfill life span - 20 years
- Post-closure period - 30 years
- Liner - Composite, consisting of 60-mil syntheti

NOTE: All costs in 1992 dollars.

Landfill Development Costs

Pre-Development Costs	
Land Options	$ 20,000
Surveying, Geotechnical	$ 30,000
Legal	$ 5,000
Real Estate Fees	$ 5,000
A. *Total Pre-Devel. Cost*	$ 60,000
Permitting Costs	
Geotechnical Investigations	$ 300,000
Engineering & Design	$ 400,000
Legal Fees	$ 300,000
Public Hearing Fees	$ 150,000
Environmental Impact Study	$ 300,000
Contingency (15%)	$ 215,000
Land (150 acres @ 3000/acre)	$ 450,000
B. *Total Permitting Cost*	$ 2,115,000
Construction Cost	
Access Roads	$ 200,000
Land Clearing	$ 50,000
Excavation-Initial Cells	$ 500,000
Fencing	$ 100,000
Landscaping	$ 50,000
Scalehouse	$ 30,000
Scales	$ 80,000
Office Building	$ 150,000
Drainage	$ 40,000
Sedimentation Ponds	$ 30,000
Utilities	$ 40,000
Monitoring Wells	$ 80,000
Methane Flare, Blowers	$ 500,000
C. *Total Construction*	$ 1,850,000

Annual Operating Costs

Equipment Fuel, Maintenance	$ 250,000
Labor	$ 400,000
Engineering	$ 40,000
Surveying	$ 10,000
Utilities	$ 15,000
Road Maintenance	$ 30,000
Seeding	$ 15,000
Operating Supplies	$ 10,000
Water Monitoring	$ 60,000
Gas Well Installation	$ 60,000
Methane Flare, Blower Operation	$ 150,000
Final Cover (Annual Closure Activity)	$ 300,000
Leachate Treatment	$ 60,000
Leachate Transportation	$ 80,000
Post-Closure Bond	$ 56,000
Insurance	$ 150,000
G&A	$ 50,000
Post-Closure Accrual	$ 562,000
Total Annual Operating Costs	$ 2,298,000

Landfill Developement Costs Continued

Liner Cost (100 Acres)	
Excavation	$ 2,726,000
Leachate Collection Gravel	$ 2,000,000
Leachate Collection Pipes	$ 800,000
Synthetic Liner	$ 2,500,000
Clay Liner	$ 3,900,000
Filter Fabric	$ 796,000
QA/QC	$ 1,000,000
D. *Total Liner Cost*	$ 13,722,000

Capital Cost	
A. Pre-Development	$ 60,000
B. Permitting	$ 2,115,000
C. Construction	$ 1,850,000
D. Liner	$ 13,722,000
Sub Total	$ 17,747,000
E. Equipment	$ 6,500,000
Total	$ 24,397,000

Source: Calculating Landfill Costs: Background and Worksheet," Browning-Ferris Industries, Houston, Texas, 1992.

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In practice, calculating landfill costs can be exceedingly difficult. The EPA provides an entire manual on its method of cost accounting, Full Cost Accounting (U.S.… Agency, 1997). Costs of operating a landfill vary dramatically between counties and between states, as well as over the lifetime of the landfill, with many of the major costs faced after closing (See

Figure 1.25.7). Economies of scale also affect costs considerably, lowering average costs for larger firms (See Figure 1.25.8). A study by Hudson and Deese (1985), for instance, found that a 200-ton-per-day facility was 27% less expensive per ton than a 50-ton-per-day facility. Relatedly, significant monopoly power can dramatically influence the profit maximizing level of marginal cost. Still, though the market is far from competitive, marginal costs are frequently assumed for the purposes of analysis to equal tipping fees, but these vary by region and vary radically by state (See Table 1.25.2 and

Table 1.25.3).

Table 1.25.2: California Tipping Fees by Year

Year	**Tipping Fees Compacted, $/ton**
1995	$31.02

1996	$34.57
1997	$34.41
1998	$33.07
1999	$34.37
2000	$37.72

(Summaries… Board)

Table 1.25.3: Average Tipping Fees by Region

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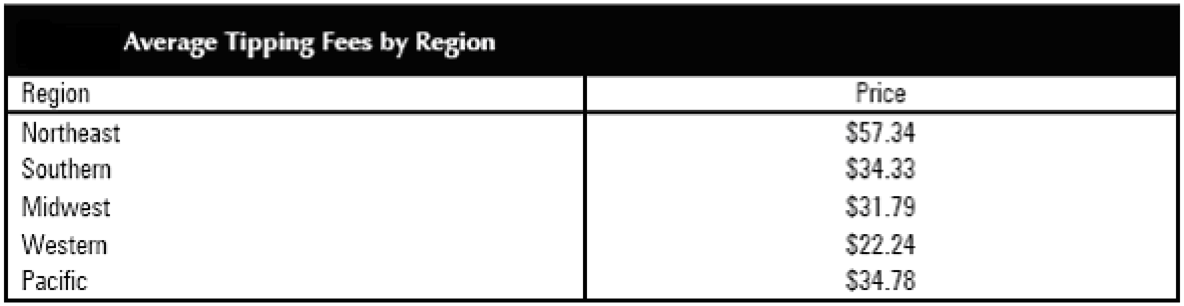

Average Tipping Fees by Region

Region	Price
Northeast	$57.34
Southern	$34.33
Midwest	$31.79
Western	$22.24
Pacific	$34.78

Source: "Solid Waste Price Index," *Solid Waste Digest*, vol. 8, no. 11 (November 1998), p.1.

1.25.1.1.1.1.2 Revenues

Landfills generate revenues from tipping fees, and more recently from selling gas directly or electricity. Tipping fees across the states range from $22.24 in the West to $57.34 in the Northeast and averaged $37.72 in California in 2000 (Solid…Index, 1998; Summaries… Board) (Table 1.25.2 and Table 1.25.3). Choate et al (2005) estimate the benefits from selling gas and electricity at prices of .045/kwhr and $4.5/mbtu, which are less then typical industrial prices. Benefits differed for firms of different sizes and technologies (Table 1.25.11). These benefits sometimes exceed the costs associated with landfill gas to energy projects, as will be discussed in greater detail later.

Collection agencies generate revenue from contracts with localities, or directly from consumers in the form of trash collection fees. In the US, both methods of collection, fees per household and payment from tax revenues, are used (Directorate… Development, 2000). Solid Waste collection contracts generally last from 1- 5 for residential services, are usually awarded by a municipality to the lowest bidder, and

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grant the right to serve a given area or district. Prices may or may not be regulated, depending on the locality. In recent years, as waste production has slowed, revenue growth has proceeded mostly from rate hikes in collection and tipping fees, responsible for 80% of revenue growth for SWM giant Allied Waste Management (Standard and Poor's, 2006).

1.25.1.1.1.1.3 Competition

Standard and Poor's (2006) contend that US MSW industries are in the middle stages of development along their business life cycles, as demonstrated by low, stable growth rates, moderate profit margins, and overcapacity. Slow growth rates, along with the increased importance of managing regulation and fuel costs, has meant that firms are focusing more on productivity and cost efficiency, in contrast with external growth and acquisition, as keys to economic success (Standard and Poor's, 2006). This is evidenced by Waste Management Inc.'s 26% percent increase in net income, to $1.18 billion, which they claim was brought about by enhancing internal efficiencies (Aseltine, McRea, Modi, Shukla, Sullivan, 2006).

The MSW industry is pursuing cost efficiency in a variety of ways. As the number of landfills have declined, fuel costs have become increasingly important as employers must transport high density waste further. The push to optimize the tradeoff between transport costs and tipping fee's has increased the focus on internalization, or the percentage of garbage collected that can be disposed in company owned facilities (Callan and Thomas, 2001; Standard and Poor's, 2006). This has also become increasingly important as the industry has consolidated, as disposing in another firms landfills has sometimes meant facing discriminatory tipping fees. Other cost reductions have been achieved by cutting jobs, and improving employer safety to reduce insurance claims etc (Standard and Poor's, 2006). Firms also increasingly demand pricing flexibility to control for inflation and other costs. (Directorate… Development, 2000)

Many cost savings and efficiencies accrue to larger sized firms. In general, MSW is capital intensive, resulting in large economies of scale. In waste collection, economies of density imply that each area is served most efficiently by a single large firm, and studies on economies of scale in waste management have demonstrated that the size of the area best served by a single firm contains 50,000 people (Directorate…Development, 2000). Benefits from vertical integration follow from cost savings associated with internalization, and also due to the demonstrated existence of economies of scope in such areas as disposal and recycling. Landfills also require massive initial investments to acquire and modify disposal space and conform to regulations. Additionally, the permitting process for landfills is prolonged, expensive, and introduces levels of risk to investing which smaller investors cannot afford. Once these investments have been made, marginal costs are small. These features and other result in conditions that facilitate natural monopoly.

In the presence of these economies, competition for the waste of residences and small business is frequently unsustainable or inefficient in collection (Directorate…Development, 2000). Stevens (1978) finds that costs are 26-48 percent higher when there is in-the-market competition in collection, contrasted against regulated private monopoly. The cost efficiencies achieved by larger landfills may be external in addition to internal. Communities often prefer to have a single, mega-landfill rather than many small landfills due to effects upon property values and other externalities. Also, once waste has been collected it is expensive to transport (except by bulk transport, like rail, which may not be mobile enough), so geographic markets for disposal are frequently "limited in scope, with limited competition between disposal facilities." (Directorate…Development, 2000).

As there are many cost benefits for incumbents which allow them to compete at a lower price, Standard and Poor's (2006) sees little incentives for waste companies to develop new landfills, and consolidation is expected to continue. Indeed, though small landfills are still a common feature of the marker, they no longer view themselves as competition for larger firms, instead desiring to become viable candidates for acquisition (Anderson, 2000). Overcapacity, which has in the past alleviated monopoly pressures on prices, is expected to be less significant in this regards as it declines and the industry matures. This has already been reflected in increases in tipping fees, up 2% from 2004 and 6.5% from 2002 (Standard and Poor's, 2006). Antitrust enforcement actions in the US have interrupted "hard-cord cartel activity" which has resulted in price-fixing, market allocation, and bid rigging (Directorate…Development, 2000). Other actions include monopolization cases against large, national firms, and regulation of mergers.

Though "some parts of the industry will not sustain competition at all," competition in-the-market is frequent for industrial and commercial wastes, where the waste is generated at high levels at each location, and competition for-the-market in the form of competitive tendering may assuage monopolistic pressure on prices in waste collection (Directorate…Development, 2000).

Waste collection accounts for 55% of MSW revenues, landfill about 35%, recycling and WTE about 5% each (Standard and Poor's, 2006).

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Emissions Regulation: Historical and Contemporary

Major historical legislation regulating waste disposal included the Solid Waste Disposal Act of 1965 and the Resource Conservation and Recovery Act (RCRA) of 1976, which by increasing sunk and fixed costs, enlarged cost-minimizing landfill size, and resulted in fewer landfills being built (Kinnaman and Fullerton, 1999). 1991's Subtitle D required installation of gas control equipment. The EPA's 1996 "Landfill Rule" mandated new emission capture systems for all landfills, requiring installation of gas control systems for landfills designed to hold 2.755 million tons and 2.5 million cubic meters or more of waste over their lifetime. This resulted in the collection of 75 percent of the gas produced by these landfills (Landfill Gas Rules, 2007).

With no consistent statewide standards for smaller and other uncontrolled landfills, California's ARB, having the primary responsibility for reducing Greenhouse gas emissions under the California Global Warming Solutions Act of 2006, has proposed measures addressing this issue (Air… Agency, 2007). The IWMB is working jointly with the ARB and plans to reduce emissions by 2-4 MMTCO2E by 2020. (California Climate…B, 2007)

AB 32 requires that all GHG reduction measures adopted and implemented by the ARB be "technologically feasible and cost-effective." (Air… Agency, 2007). "The ARB interprets "cost-effectiveness"… as the number of dollars expended per metric ton of Co2E.q gases reduced…each strategy is expected to meet a yet-to-be-determined cost-effectiveness threshold…that is equitable relative to the GHG reduction achieved" (Air… Agency, 2007).

California Landfills

The integrated waste management board counted 148 permitted active solid waste landfills in California today. This number has declined dramatically in recent years, from around 300 in the early 2000's, implying rapid consolidation of the industry (Personal…Management, 2007). The California Economic Census (2002) calculated receipts of $6,427,257,000 for waste management services, and $1,549,598,000 in annual payroll covering 38,905 paid employees (See Table 1.25.4). Of these, solid waste landfill establishments totaled receipts of $494,830,000, and had an annual payroll of $79,275,000 paid to 1,786 employees.

Like the nation as a whole, California SWM and Landfills in particular are ‘fragmented’, but general industry statistics and trends can be uncovered. California GDP growth is expected to total 2.4 percent in 2007 and 2.9 percent in 2008, as compared to 3.3 percent in 2006 (Economic Outlook… 2007-2008). Considering also the downturn that is projected to continue in housing markets, waste should grow relatively slowly, at near or below 2% per year (Choate et al., 2005). In 1990, Californians generated approximately 50.9 million tons of waste, and disposed of near 42.4 million tons (Solid… Data). Waste diversion in California has increased sevenfold since then, and California now diverts 52 percent of its waste, leaving 42 million tons of waste per year to be disposed (Total…Disposed) (See

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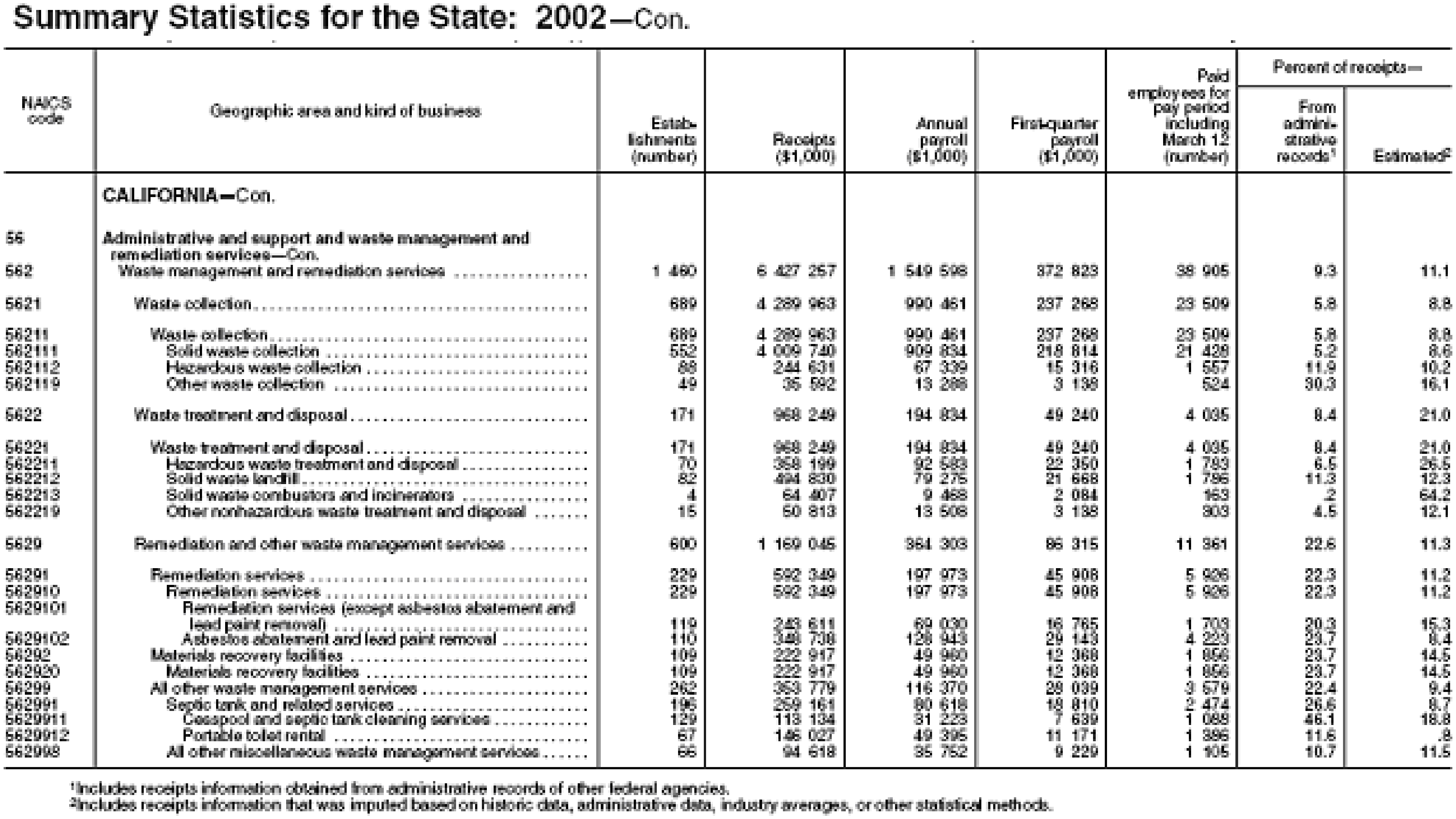
Table 1.25.5 and

Figure 1.25.9).

A 2003 study contracted for by the IWMB surveyed 224 landfills of which 158 were active or partially active, 34 were inactive, 31 were closed, and 1 was partly inactive and partly closed (Landfill… Landfills, 2003). Most California specific data will be from this report.

Table 1.25.4: California Economic Census Data



Summary Statistics for the State: 2002—Con.

NAICS code	Geographic area and kind of business	Establishments (number)	Receipts ($1,000)	Annual payroll ($1,000)	First-quarter payroll ($1,000)	Paid employees for pay period including March 12 (number)	Percent of receipts— From administrative records[1]	Percent of receipts— Estimated[2]
	CALIFORNIA—Con.							
56	**Administrative and support and waste management and remediation services—Con.**							
562	Waste management and remediation services	1 460	6 427 257	1 549 598	372 823	38 905	9.3	11.1
5621	Waste collection	689	4 289 963	990 461	237 268	23 509	5.8	8.8
56211	Waste collection	689	4 289 963	990 461	237 268	23 509	5.8	8.8
562111	Solid waste collection	552	4 009 740	909 834	218 814	21 428	5.2	8.6
562112	Hazardous waste collection	88	244 631	67 339	15 316	1 557	11.9	10.2
562119	Other waste collection	49	35 592	13 288	3 138	524	30.3	16.1
5622	Waste treatment and disposal	171	968 249	194 834	49 240	4 035	8.4	21.0
56221	Waste treatment and disposal	171	968 249	194 834	49 240	4 035	8.4	21.0
562211	Hazardous waste treatment and disposal	70	358 199	92 583	22 350	1 783	6.5	26.5
562212	Solid waste landfill	82	494 830	79 275	21 668	1 786	11.3	12.3
562213	Solid waste combustors and incinerators	4	64 407	9 468	2 084	163	.2	64.2
562219	Other nonhazardous waste treatment and disposal	15	50 813	13 508	3 138	303	4.5	12.1
5629	Remediation and other waste management services	600	1 169 045	364 303	86 315	11 361	22.6	11.3
56291	Remediation services	229	592 349	197 973	45 908	5 926	22.3	11.2
562910	Remediation services	229	592 349	197 973	45 908	5 926	22.3	11.2
5629101	Remediation services (except asbestos abatement and lead paint removal)	119	243 611	69 030	16 765	1 703	20.3	15.3
5629102	Asbestos abatement and lead paint removal	110	348 738	128 943	29 143	4 223	23.7	8.4
56292	Materials recovery facilities	109	222 917	49 960	12 368	1 856	23.7	14.5
562920	Materials recovery facilities	109	222 917	49 960	12 368	1 856	23.7	14.5
56299	All other waste management services	262	353 779	116 370	28 039	3 579	22.4	9.4
562991	Septic tank and related services	196	259 161	80 618	18 810	2 474	26.6	8.7
5629911	Cesspool and septic tank cleaning services	129	113 134	31 223	7 639	1 088	46.1	18.8
5629912	Portable toilet rental	67	146 027	49 395	11 171	1 386	11.6	.8
562998	All other miscellaneous waste management services	66	94 618	35 752	9 229	1 105	10.7	11.5

[1] Includes receipts information obtained from administrative records of other federal agencies.

[2] Includes receipts information that was imputed based on historic data, administrative data, industry averages, or other statistical methods.

(California Economic Census, 2002)

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Table 1.25.5: Diversion Rates

Year	Percent Diverted
1995	28
1996	31
1997	32
1998	33
1999	37
2000	42
2001	44
2002	48
2003	47
2004	48
2005	53

In accord with national trends, the great majority of California Landfills were built in the 60's or 70's, with only 3.6% built in the 90's (See Figure 1.25.10) (Landfill… Landfills, 2003). 75% of these sites had pubic ownership and 25% had private (See

Figure 1.25.11). 32% of landfills surveyed were located within an urban setting, 6% within a suburban, and 62% within a rural. 53% of landfills were classified as inland, and 26% desert.

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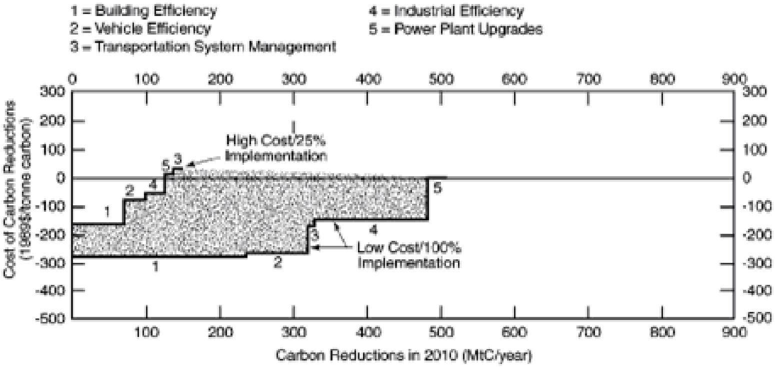
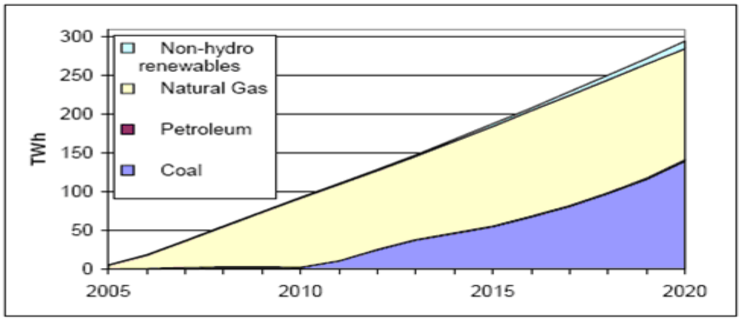
Landfill size can be measured in various ways. California landfills in the 2003 survey had a median permitted disposal area of 55.5 acres, with 66% of landfills between 10 and 160 acres, and 91% between 2 and 320 acres (Landfill… Landfills, 2003) (See Figure 1.25.12). Median permitted disposal volume was 2.7 million cubic yards (See Figure 1.25.13). For the state as a whole, permitted max daily tonnage was 195,500 tons (See Figure 1.25.14). The median was 395 tons, and 68% of landfills had permits for between 100 and 4,900 tons.

Figure 1.25.1: NAS Study



(Brown et al, 1998)

Figure 1.25.2: Avoided Generation by Source, 2005- 2020, Best Practices Scenario



(Energy Efficiency Task Force, 2005)

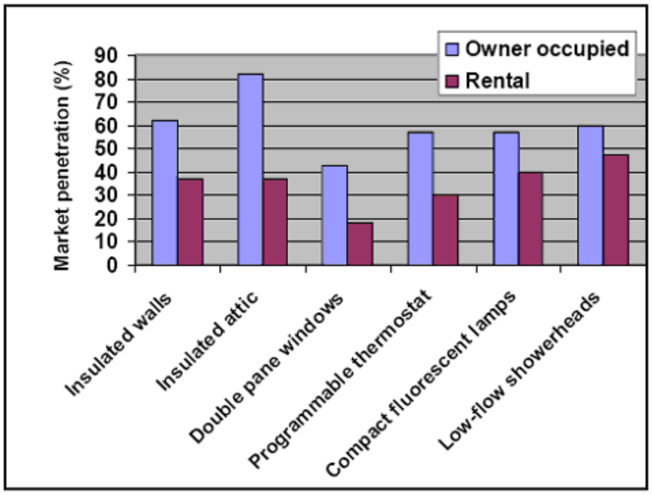
Remaining capacity for California Landfills was estimated at 1.5 billion cubic yards (See

Figure 1.25.15 and

Figure 1.25.17) (Landfill… Landfills, 2003). The median active California landfill had 2,153,800 cubic yards remaining disposal capacity. "Today, 21 of the state's 58 counties, having 41 percent of the population, will exhaust their disposal capacity within 15 years. Of these, 17 have 8 years or less capacity. It takes 7 to 10 years to plan, design, and permit a new landfill" (Beyond… Landfills, 1996). While excess capacity may endure for the nation, it will not in California. Remaining capacity clustered around the population centers of San Francisco, Los Angeles, Sacramento and San Diego (See

Figure 1.25.17). Closure patterns "suggest that, increasingly, portions of primarily rural California cannot meet the landfill needs of their residents without hauling out of county or to neighboring states. Often, smaller, rural, county-owned landfills have closed and waste streams have been diverted to larger, centralized landfills" (Landfill….Landfills, 2005).

Figure 1.25.3: Role of Split Incentives in Efficiency investments in Housing

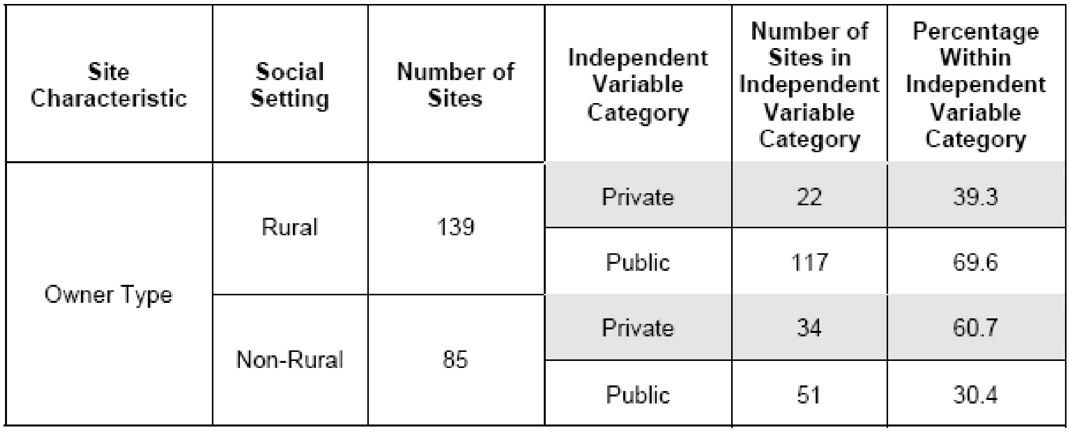


(Energy Efficiency Task Force, 2005)

Landfill characteristics are not independent of one another (See

Table 1.25.6 and Table 1.25.7). Urban sites were much more likely to be private then rural sites (Landfill… Landfills, 2003). While 61% of private sites were non rural, only 30% of public were. Also, urban sites are typically larger than rural sites, as most of the small landfills are in rural social settings. While 75% of non rural sites were over 122 acres, only 35% of rural sites were. Taken together, private firms appear much more likely to be over 122 acres than public entities. Moreover since private firms are more flexible in their location decisions than government waste entities and are attracted to the locations where waste streams are the highest, it is fair to speculate that this pattern persists throughout the distribution of landfill size, with private ownership clustering around the top. Evidence for this also comes from the IWMB survey's note that in 2003, sites with landfill gas systems were 4.7 times more likely to be private. The Landfill Gas Rule mandated that only the largest landfills, over 2.755 MMT, install gas collection systems.

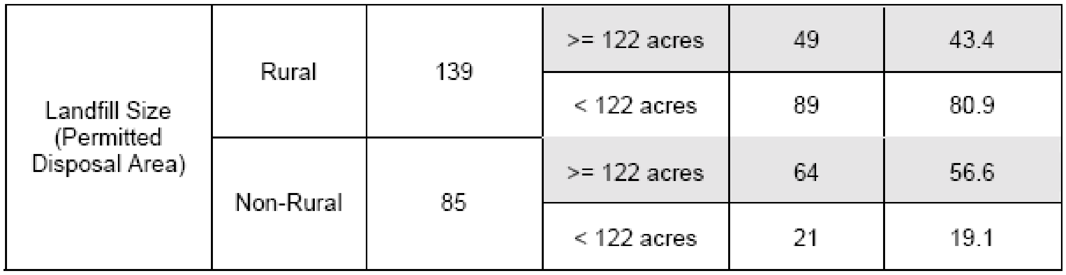
Table 1.25.6: Dependence between Ownership and Social Setting



Site Characteristic	Social Setting	Number of Sites	Independent Variable Category	Number of Sites in Independent Variable Category	Percentage Within Independent Variable Category
Owner Type	Rural	139	Private	22	39.3
			Public	117	69.6
	Non-Rural	85	Private	34	60.7
			Public	51	30.4

(Landfill… Landfills, 2003)

Table 1.25.7: Dependence between Landfill Size and Social Setting



Landfill Size (Permitted Disposal Area)	Rural	139	>= 122 acres	49	43.4
			< 122 acres	89	80.9
	Non-Rural	85	>= 122 acres	64	56.6
			< 122 acres	21	19.1

(Landfill… Landfills, 2003)

The facts that smaller, rural landfills are increasingly being closed and find their waste steams diverted to larger urban landfills, combined with the information that urban sites are far more likely to be private, implies that the private sector is becoming increasingly dominant in the California landfill industry, and are handling ever greater portions of California’s waste. This allows for the revealing insight that, as the private/urban sites are already dramatically larger than rural/public sites, the largest Landfills are becoming increasingly large at the same time that they face decreasing levels of competition. The industry is therefore consolidating in such a way that gives private landfills increasing

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degrees of monopoly control over larger vicinities. While Segal and Moore (2000) note that greater competition in the west has helped lower tipping fee's relative to the east, Anderson (2000) describes how it is only recently, with the two largest companies controlling nearly 40% of the national market, that corporations have finally been able to begin leveraging their market power in solid waste. Anderson finds evidence of this in such cases as trials by WMI, dramatically increasing tipping fees in the Northwest, and small firms no longer viewing themselves as threats so much as potential acquisition candidates.

Technology

The various technologies used in landfill are significant for determining landfill costs and revenues. The IWMB survey (2003) divides liners into four types. 1.8% of landfill were fully lined in accords with subtitle D in the CFR (40 CFR 258), 5% were classified as fully lined but only partially in accord with subtitle D, 31% were partially unlined, and 62% were fully unlined. 21% of landfill has a full cover, 14% were partially covered, and 65% were fully uncovered.18% of landfills disposed of solid waste by filling a canyon, 32% by lying it across a flat area, 11% by filling an excavated trench, 2% by filling across a sloped area, 3% by filling a pit or quarry that was excavated by a purpose besides that of conducting landfill operations, and 34% disposed of their solid waste in some combination of these. The California climate action team notes that 94% of California landfills have gas collection systems in place (California Climate…B, 2007).

The EPA currently lists 74 active (88 total) operational landfill gas to energy projects in California, with 5 under construction, and another 38 listed as "candidates which present attractive opportunities for project development" (Landfill… Program). Both active and inactive landfills are candidates for gas to energy projects, but landfill age effects profitability. Nine of the landfills have direct use systems installed. Direct gas use projects capture gas from landfills and transport it directly to a nearby facility for use as a fuel (Choate et al, 2005). 79 have electricity projects installed, which capture landfill gas and use it to generate electricity (Landfill… Program; Choate et al, 2005). Of these, two use alternative fuels, two use boilers, five use cogeneration, one uses a combined cycle, four use direct thermal, nine use gas turbine, one uses liquefied natural gas, 12 use microturbines, 47 use reciprocating engine, and five use a steam turbine (Landfill… Program).

California Reductions Opportunity and associated Costs/Savings

The ARB and IWMB strategies for reducing GHG emissions from MSW landfills include (1) the installation of emission control systems (early action measure), (2) increasing gas to energy projects, and (3) enhancing methane capture efficiency by such methods as earlier placement of final cover. According to the agency, strategies 1 and 3 should result in emissions reductions of 1 MMTCO2E for 2010 and 3 MMTCO2E for 2020 (California Climate…B, 2007). ARB staff are “proposing to expand the scope of strategy 1 to include efficiency controls resulting in 2 to 4 MMTCO2E by 2020.” (Air… Agency, 2007).

Choate et al (2005) conducted a study to determine the savings/costs associated with energy generation from non-Co2 gases in a variety of industries, including Landfills. Analysis was conducted for two scenarios: Scenario A with a 4 percent discount rate and a 0 percent tax rate, and Scenario B with a 20 percent discount rate and a 40 percent tax rate. Scenario A was designed to approximate costs from a societal perspective, while Scenario B was intended to estimate private costs. Costs were looked at in terms of the break-even price, which refers to the price that could be paid to an individual at which she/he would be indifferent with regards to whether to institute an option. With relevance to a carbon cap at $50/MTCo2 for instance, firms would purchase credits for emissions at which the breakeven price was over $50/MTCo2.

For Scenario A, measures suggested in the report had the capacity to reduce emissions of 20.7 MMTCO2 Eq. in 2010, and 31.6 MMTCO2 Eq. in 2020 at a breakeven price of $50/MTCo2 or less (Choate et al 2005). Of all the industries considered, landfills represented the greatest opportunity for emission reductions, at 9.0 MMTCO2 Eq. for 2010 and 9.7 MMTCO2 Eq. in 2020. At a breakeven price of $0/MTCO2Eq. (net savings) or less, a total of 5.9 MMTCO2 Eq. of potential reductions in 2010, and 8.7 MMTCO2 Eq. in 2020 could be achieved, and together landfill and manure management accounted for 86% of these reductions.

Landfills were also the most important venue for reducing emissions in Scenario B (Choate et al 2005). At a breakeven price $20/MTCO2Eq. or less landfill emissions accounted for over 58 percent of the possible reductions in 2010 and 48 percent of those possible in 2020. Landfills further constituted 70% and 60%, respectively, of the 1.7 MMTCO2E. of potential reductions in 2010 and the 2.1 MMTCO2E. in 2020 that could be achieved at a breakeven price of $0/MTCO2Eq. (savings) or less.

Choate et al (2005) estimated the capital and operating costs of installing various technologies for different levels of Waste In Place (Costs of projects were driven primarily by size/economies of scale and age) (See Table 1.25.8, Table 1.25.9, and Table 1.25.10). After predicting the technologies that would be used by the landfills for each size category based upon the technical applicability (the % of emissions that can be reduced by a given technology) and market penetration (the % of emissions that a given technology is expected to address given firms’ preferences) of each technology, Choate and coauthors then calculated the costs and benefits per MTCO2 Eq. for firms in each size category

(See Table 1.25.11). Costs referred to the capital investment and operating costs of the various technologies, whereas benefits referred to revenues from selling the gas or electricity.

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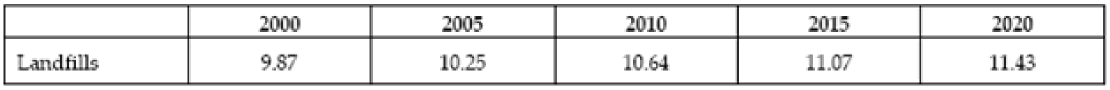
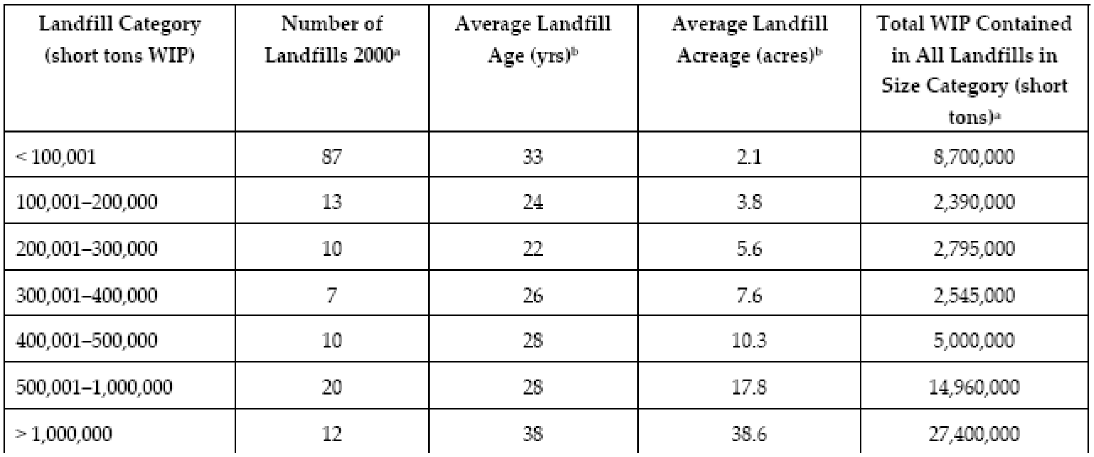
Table 1.25.8: Methane Emission Predicted Baseline Emissions for Landfills (MMTCO2E).



	2000	2005	2010	2015	2020
Landfills	9.87	10.25	10.64	11.07	11.43

(Choate et al, 2005)

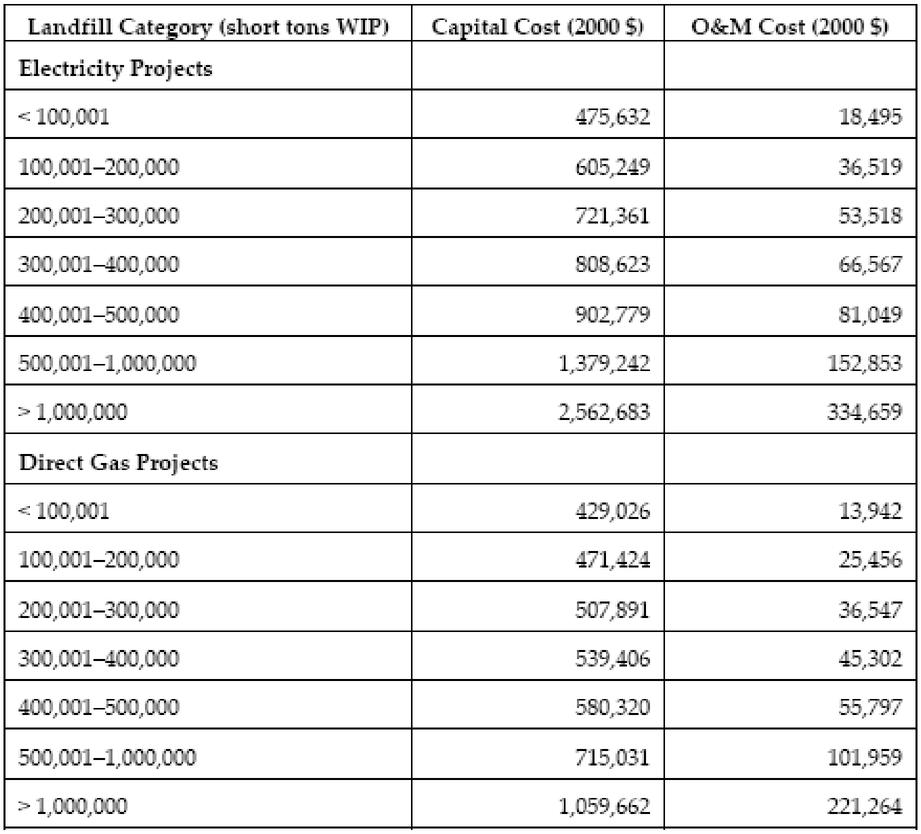
Table 1.25.9: Landfill Size Category Characteristics



Landfill Category (short tons WIP)	Number of Landfills 2000[a]	Average Landfill Age (yrs)[b]	Average Landfill Acreage (acres)[b]	Total WIP Contained in All Landfills in Size Category (short tons)[a]
< 100,001	87	33	2.1	8,700,000
100,001–200,000	13	24	3.8	2,390,000
200,001–300,000	10	22	5.6	2,795,000
300,001–400,000	7	26	7.6	2,545,000
400,001–500,000	10	28	10.3	5,000,000
500,001–1,000,000	20	28	17.8	14,960,000
> 1,000,000	12	38	38.6	27,400,000

(Choate et al, 2005)

Table 1.25.10: Landfill Capital and Operation and Maintenance Costs



Landfill Category (short tons WIP)	Capital Cost (2000 $)	O&M Cost (2000 $)
Electricity Projects		
< 100,001	475,632	18,495
100,001–200,000	605,249	36,519
200,001–300,000	721,361	53,518
300,001–400,000	808,623	66,567
400,001–500,000	902,779	81,049
500,001–1,000,000	1,379,242	152,853
> 1,000,000	2,562,683	334,659
Direct Gas Projects		
< 100,001	429,026	13,942
100,001–200,000	471,424	25,456
200,001–300,000	507,891	36,547
300,001–400,000	539,406	45,302
400,001–500,000	580,320	55,797
500,001–1,000,000	715,031	101,959
> 1,000,000	1,059,662	221,264

(Choate et al, 2005)

Table 1.25.11: Mitigation Options for Landfills

Name	Description	MP (%)	TA (%)	RE (%)	Capital Cost[a]	Annual Cost[a]	Benefits[a]
Direct Gas Use, WIP < 100,001 short tons	Installation of a direct gas project at landfills with a WIP up to 100,000 short tons	0	14	85	152.91	4.97	9.25
Direct Gas Use, WIP 100,001–200,000 short tons	Installation of a direct gas project at landfills with a WIP between 100,001 and 200,000 short tons	0	4	85	68.57	3.70	9.18
Direct Gas Use, WIP 200,001–300,000 short tons	Installation of a direct gas project at landfills with a WIP between 200,001 and 300,000 short tons	0	4	85	47.44	3.41	9.07
Direct Gas Use, WIP 300,001–400,000 short tons	Installation of a direct gas project at landfills with a WIP between 300,001 and 400,000 short tons	33	4	85	41.74	3.51	9.36
Direct Gas Use, WIP 400,001–500,000 short tons	Installation of a direct gas project at landfills with a WIP between 400,001 and 500,000 short tons	50	8	85	37.73	3.63	9.34
Direct Gas Use, WIP 500,001–1,000,000 short tons	Installation of a direct gas project at landfills with a WIP between 500,001 and 1,000,000 short tons	29	23	85	23.09	3.29	9.34
Direct Gas Use, WIP 1,000,000+ short tons	Installation of a direct gas project at landfills with a WIP greater than 1,000,000 short tons	31	43	85	15.00	3.13	9.16
Electricity, WIP < 100,001 short tons	Installation of an electricity project at landfills with a WIP up to 100,000 short tons	100	14	85	169.53	6.59	7.81
Electricity, WIP 100,001–200,000 short tons	Installation of an electricity project at landfills with a WIP between 100,001 and 200,000 short tons	100	4	85	88.04	5.31	7.76
Electricity, WIP 200,001–300,000 short tons	Installation of an electricity project at landfills with a WIP between 200,001 and 300,000 short tons	100	4	85	67.39	5.00	7.67
Electricity, WIP 300,001–400,000 short tons	Installation of an electricity project at landfills with a WIP between 300,001 and 400,000 short tons	67	4	85	62.57	5.15	7.91
Electricity, WIP 400,001–500,000 short tons	Installation of an electricity project at landfills with a WIP between 400,001 and 500,000 short tons	50	8	85	58.70	5.27	7.89
Electricity, WIP 500,001–1,000,000 short tons	Installation of an electricity project at landfills with a WIP between 500,001 and 1,000,000 short tons	71	23	85	44.54	4.94	7.90
Electricity, WIP 1,000,000+ short tons	Installation of an electricity project at landfills with a WIP greater than 1,000,000 short tons	69	43	85	36.27	4.74	7.74

MP = Market Penetration; TA = Technical Applicability; RE = Reduction Efficiency

[a] All costs and benefits are expressed in year 2000 \$ per $MTCO_2$ Eq.

(Choate et al, 2005)

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Finally, Choate and coauthors calculated the breakeven prices associated with the various emissions reductions under each scenario (See

Table 1.25.12, Table 1.25.13, Table 1.25.14, and Table 1.25.15). Using a marginal abatement cost curve that was calculated from the data in their report, one can easily identify the measures for which there are net cost savings (breakeven price of $0 or less) and points before which there is a dramatic increase in the break-even price (See Table 1.25.13 and Table 1.25.14). It is important to remember that this curve applies to marginal abatement at the industry level, that each breakeven price is associated with firms from a given size and technology group who reduce emissions by a certain amount at that price. Cumulative emissions reductions are found by summing the emissions reductions of each of these size/technology groups at escalating breakeven prices.

That said, under Scenario A with a discount rate of 4% and tax rate of 0%, landfills could reduce up to 2.28 MMTCO2E. with net cost savings in 2010, and up to 2.44 MMTCO2E. with net cost savings in 2020. Furthermore, at a breakeven price of $1.04/MTCO2Eq or less, landfills could reduce up to 6.48 MMTCO2E. in 2010 and up to 6.96 MMTCO2 in 2020. At a breakeven price of $3.39/MTCO2Eq or less, landfills could reduce up to 7.47 MMTCO2E. in 2010 and up to 8.02 MMTCO2E. in 2020. Finally, they could achieve the full amount of reductions of up to 9.04 MMTCO2E. in 2010 and up to 9.71 MMTCO2 in 2020Eq. at a breakeven price of $14.03/MTCO2Eq or less.

Under Scenario B with a discount rate of 20% and tax rate of 40%, landfills could reduce up to 1.19 MMTCO2E. with net cost savings in 2010, and up to 1.28 MMTCO2 with net cost savings in 2020. Furthermore, at a breakeven price of $10.94/MTCO2Eq or less, landfills could reduce up to 6.48 MMTCO2E. in 2010 and up to 6.96 MMTCO2E. in 2020. At a breakeven price of $18.36/MTCO2Eq or less, landfills could reduce up to 7.47 MMTCO2E. in 2010 and up to 8.02 MMTCO2E. in 2020. Finally, they could achieve the full amount of reductions of up to 9.04 MMTCO2E in 2010 and up to 9.71 MMTCO2E. in 2020 at a breakeven price of $51.68/MTCO2Eq or less.

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Table 1.25.12: Emissions Reductions and Breakeven Prices (Scenario A, 2010) Year- 2010, DR 4% TR 0%

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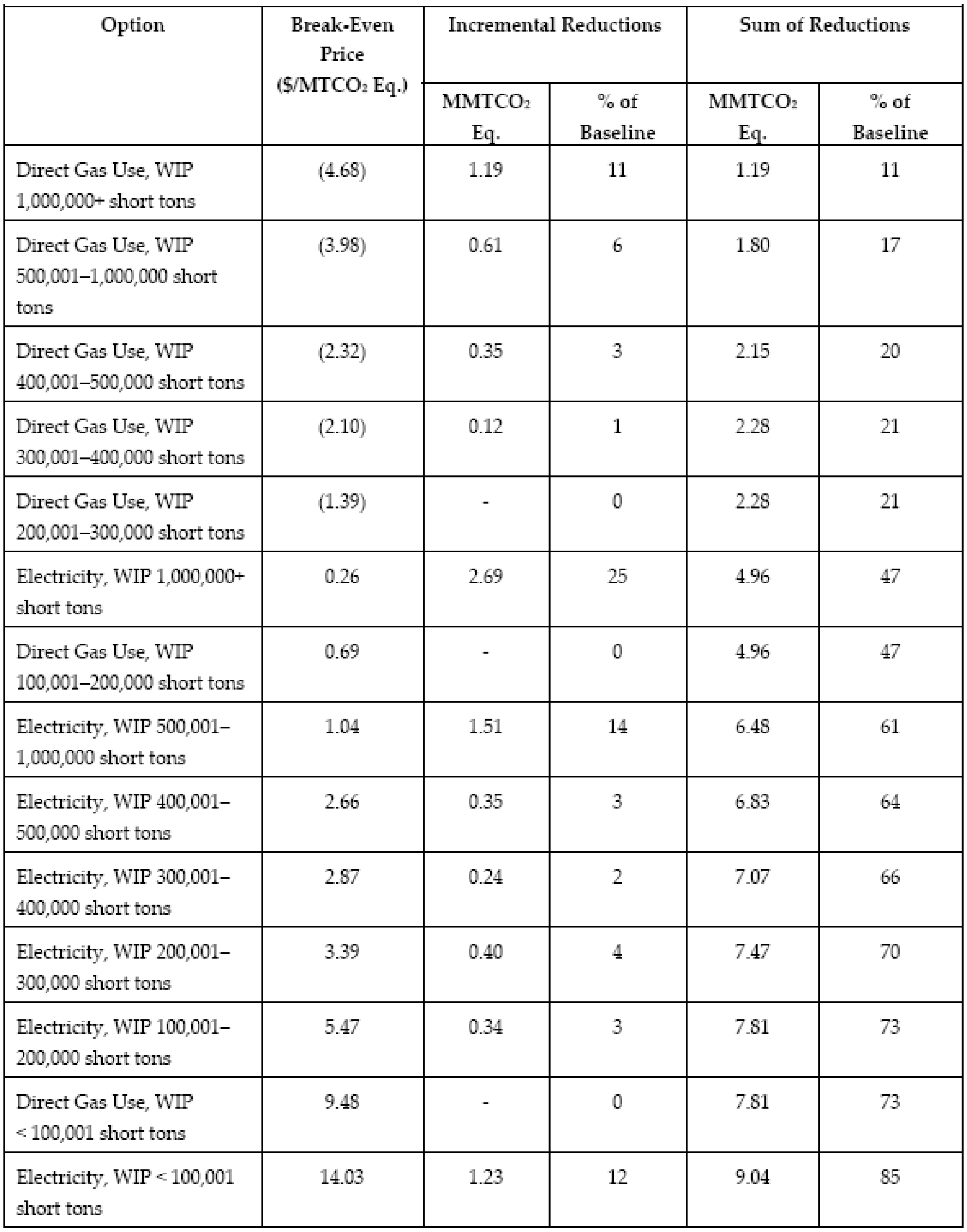

Option	Break-Even Price ($/MTCO$_2$ Eq.)	Incremental Reductions		Sum of Reductions	
		MMTCO$_2$ Eq.	% of Baseline	MMTCO$_2$ Eq.	% of Baseline
Direct Gas Use, WIP 1,000,000+ short tons	(4.68)	1.19	11	1.19	11
Direct Gas Use, WIP 500,001–1,000,000 short tons	(3.98)	0.61	6	1.80	17
Direct Gas Use, WIP 400,001–500,000 short tons	(2.32)	0.35	3	2.15	20
Direct Gas Use, WIP 300,001–400,000 short tons	(2.10)	0.12	1	2.28	21
Direct Gas Use, WIP 200,001–300,000 short tons	(1.39)	-	0	2.28	21
Electricity, WIP 1,000,000+ short tons	0.26	2.69	25	4.96	47
Direct Gas Use, WIP 100,001–200,000 short tons	0.69	-	0	4.96	47
Electricity, WIP 500,001–1,000,000 short tons	1.04	1.51	14	6.48	61
Electricity, WIP 400,001–500,000 short tons	2.66	0.35	3	6.83	64
Electricity, WIP 300,001–400,000 short tons	2.87	0.24	2	7.07	66
Electricity, WIP 200,001–300,000 short tons	3.39	0.40	4	7.47	70
Electricity, WIP 100,001–200,000 short tons	5.47	0.34	3	7.81	73
Direct Gas Use, WIP < 100,001 short tons	9.48	-	0	7.81	73
Electricity, WIP < 100,001 short tons	14.03	1.23	12	9.04	85

(Choate et al, 2005)

Table 1.25.13: Emissions Reductions and Breakeven Prices (Scenario A, 2020) Year- 2020, DR 4% TR 0%

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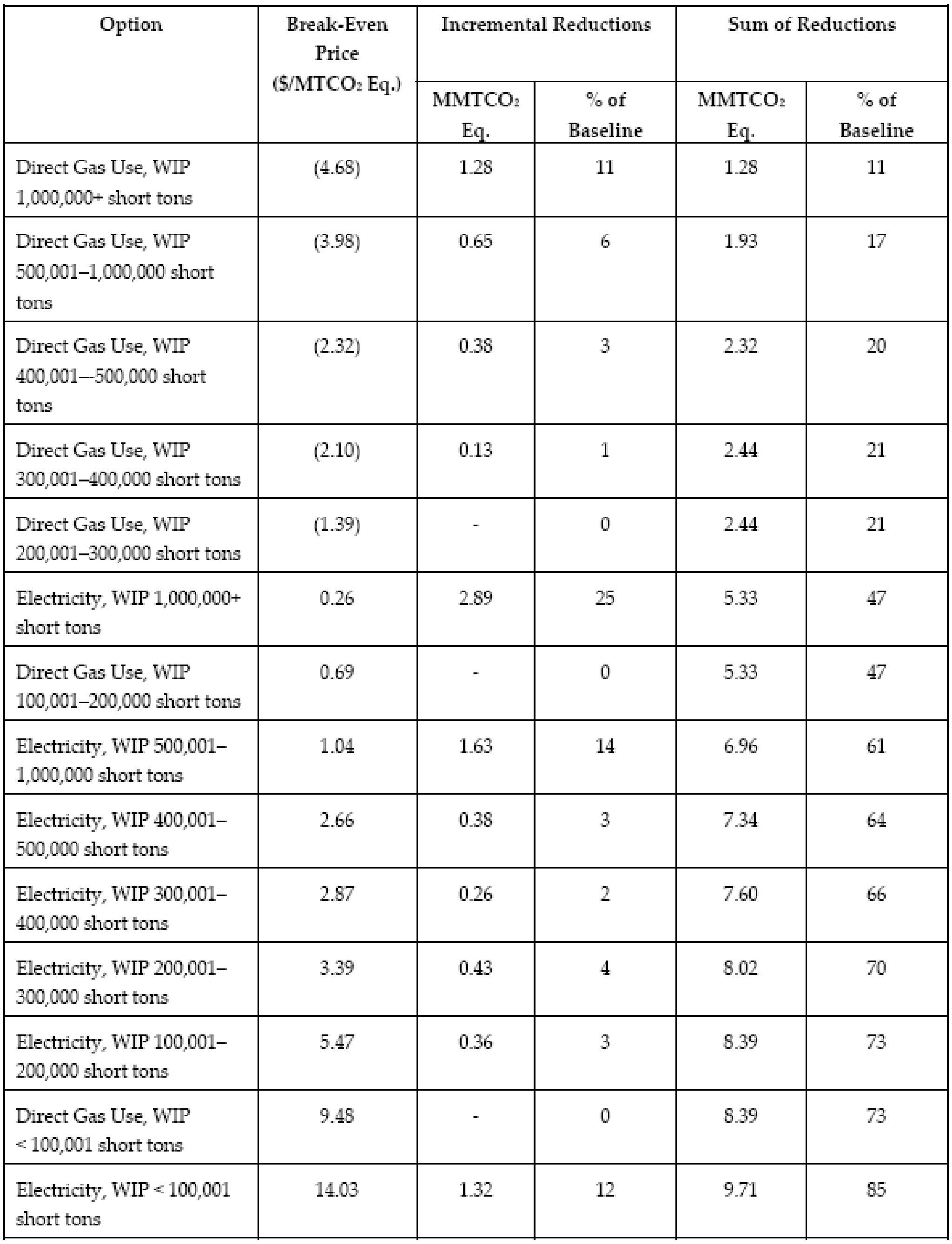
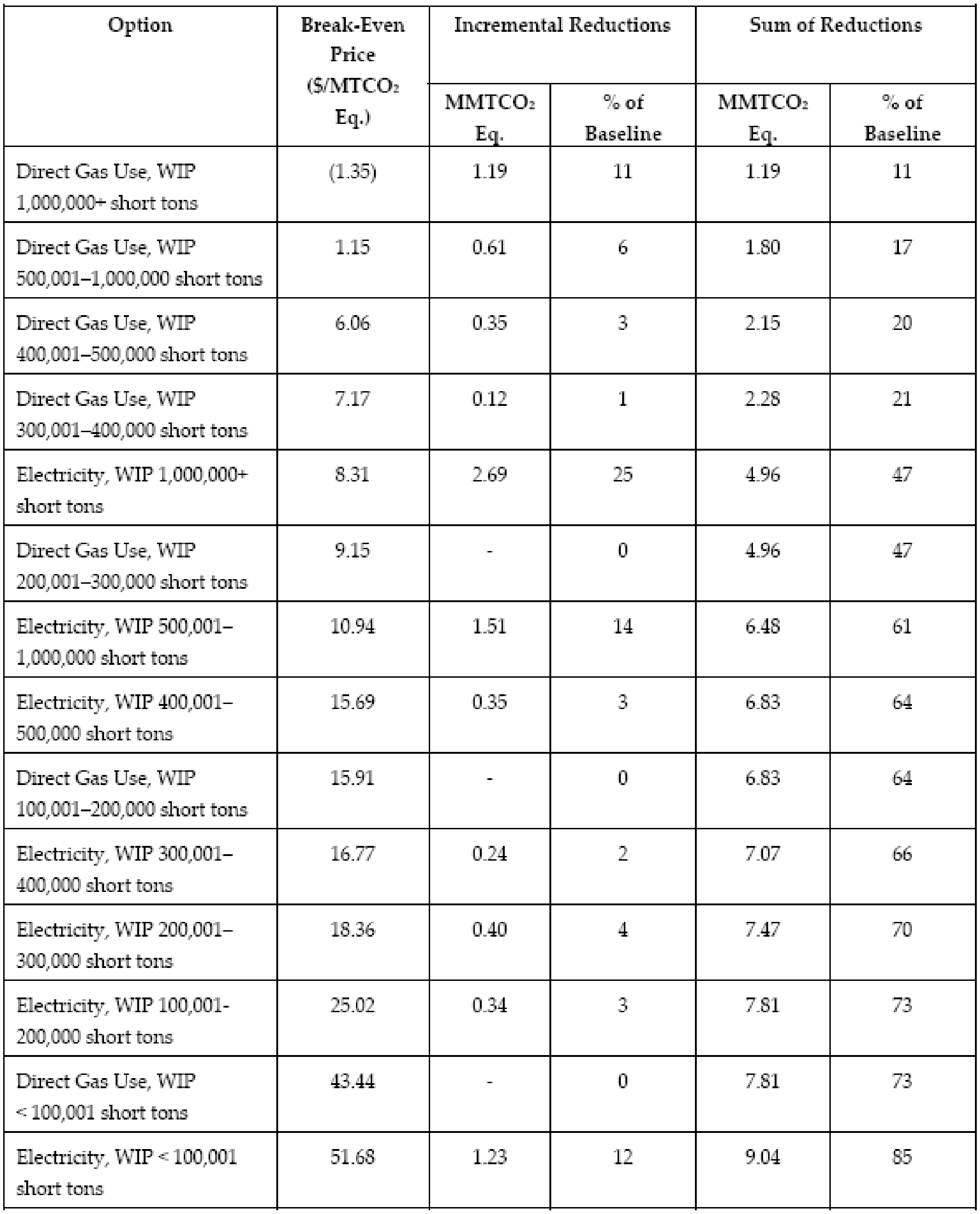


Option	Break-Even Price ($/MTCO₂ Eq.)	Incremental Reductions		Sum of Reductions	
		MMTCO₂ Eq.	% of Baseline	MMTCO₂ Eq.	% of Baseline
Direct Gas Use, WIP 1,000,000+ short tons	(4.68)	1.28	11	1.28	11
Direct Gas Use, WIP 500,001–1,000,000 short tons	(3.98)	0.65	6	1.93	17
Direct Gas Use, WIP 400,001—500,000 short tons	(2.32)	0.38	3	2.32	20
Direct Gas Use, WIP 300,001–400,000 short tons	(2.10)	0.13	1	2.44	21
Direct Gas Use, WIP 200,001–300,000 short tons	(1.39)	-	0	2.44	21
Electricity, WIP 1,000,000+ short tons	0.26	2.89	25	5.33	47
Direct Gas Use, WIP 100,001–200,000 short tons	0.69	-	0	5.33	47
Electricity, WIP 500,001–1,000,000 short tons	1.04	1.63	14	6.96	61
Electricity, WIP 400,001–500,000 short tons	2.66	0.38	3	7.34	64
Electricity, WIP 300,001–400,000 short tons	2.87	0.26	2	7.60	66
Electricity, WIP 200,001–300,000 short tons	3.39	0.43	4	8.02	70
Electricity, WIP 100,001–200,000 short tons	5.47	0.36	3	8.39	73
Direct Gas Use, WIP < 100,001 short tons	9.48	-	0	8.39	73
Electricity, WIP < 100,001 short tons	14.03	1.32	12	9.71	85

(Choate et al, 2005)

Table 1.25.14: Emissions Reductions and Breakeven Prices (Scenario B, 2010) Year- 2010, DR 20% TR 40%



Option	Break-Even Price ($/MTCO₂ Eq.)	Incremental Reductions		Sum of Reductions	
		MMTCO₂ Eq.	% of Baseline	MMTCO₂ Eq.	% of Baseline
Direct Gas Use, WIP 1,000,000+ short tons	(1.35)	1.19	11	1.19	11
Direct Gas Use, WIP 500,001–1,000,000 short tons	1.15	0.61	6	1.80	17
Direct Gas Use, WIP 400,001–500,000 short tons	6.06	0.35	3	2.15	20
Direct Gas Use, WIP 300,001–400,000 short tons	7.17	0.12	1	2.28	21
Electricity, WIP 1,000,000+ short tons	8.31	2.69	25	4.96	47
Direct Gas Use, WIP 200,001–300,000 short tons	9.15	-	0	4.96	47
Electricity, WIP 500,001–1,000,000 short tons	10.94	1.51	14	6.48	61
Electricity, WIP 400,001–500,000 short tons	15.69	0.35	3	6.83	64
Direct Gas Use, WIP 100,001–200,000 short tons	15.91	-	0	6.83	64
Electricity, WIP 300,001–400,000 short tons	16.77	0.24	2	7.07	66
Electricity, WIP 200,001–300,000 short tons	18.36	0.40	4	7.47	70
Electricity, WIP 100,001-200,000 short tons	25.02	0.34	3	7.81	73
Direct Gas Use, WIP < 100,001 short tons	43.44	-	0	7.81	73
Electricity, WIP < 100,001 short tons	51.68	1.23	12	9.04	85

(Choate et al, 2005)

Table 1.25.15: Emissions Reductions and Breakeven Prices (Scenario B, 2020) Year- 2020, DR 20% TR 40%

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Option	Break-Even Price ($/MTCO$_2$ Eq.)	Incremental Reductions		Sum of Reductions	
		MMTCO$_2$ Eq.	% of Baseline	MMTCO$_2$ Eq.	% of Baseline
Direct Gas Use, WIP 1,000,000+ short tons	(1.35)	1.28	11	1.28	11
Direct Gas Use, WIP 500,001–1,000,000 short tons	1.15	0.65	6	1.93	17
Direct Gas Use, WIP 400,001–500,000 short tons	6.06	0.38	3	2.32	20
Direct Gas Use, WIP 300,001–400,000 short tons	7.17	0.13	1	2.44	21
Electricity, WIP 1,000,000+ short tons	8.31	2.89	25	5.33	47
Direct Gas Use, WIP 200,001–300,000 short tons	9.15	-	0	5.33	47
Electricity, WIP 500,001–1,000,000 short tons	10.94	1.63	14	6.96	61
Electricity, WIP 400,001–500,000 short tons	15.69	0.38	3	7.34	64
Direct Gas Use, WIP 100,001–200,000 short tons	15.91	-	0	7.34	64
Electricity, WIP 300,001–400,000 short tons	16.77	0.26	2	7.60	66
Electricity, WIP 200,001–300,000 short tons	18.36	0.43	4	8.02	70
Electricity, WIP 100,001–200,000 short tons	25.02	0.36	3	8.39	73
Direct Gas Use, WIP < 100,001 short tons	43.44	-	0	8.39	73
Electricity, WIP < 100,001 short tons	51.68	1.32	12	9.71	85

(Choate et al, 2005)

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Regulatory Impact

Landfill may be the best situated of any of the industry groups that emit non-Co2 greenhouse gases to respond favorably to regulation, or in such a way that regulation does not dramatically decrease profitability or distort profit maximizing production decisions. This is true for all strategies being considered by the ARB and IWMB, including strategy 1 to install emissions control systems, strategy 2 to promote use of gas to energy projects, and strategy 3 to enhance methane capture efficiencies, and regardless of whether these strategies are achieved through carbon caps or legal imperatives.

This expected vitality can be attributed to four features of solid waste industries, and landfills in particular. The first feature relates to the direct impact of regulation upon industry cost and revenue structure. The second two features relate to firms' ability to transfer costs to consumers, and the fourth to industry culture and firms' preferences in cost minimization.

Currently ARB and IWMB intend for strategies 1 and 3 to reduce emissions by 2-4 MMTCO2 by 2020. The extent to which reductions from these strategies will impose costs upon firms is something of an unknown. Still, if there are costs, one can presume they will not be dramatic. Since AB-32 has the mandate to implement only cost effective measures, measures that threaten financial viability will not likely be considered. As noted in the Climate Action Team report, 94% of California's landfills have gas collection systems in place, proving that the landfills can flourish under these conditions. Moreover, given the intensiveness of capital in landfill, capital upgrades to best capture practices can only constitute a tiny fraction of total investment costs.

While the reductions from strategy 2 were not calculated by the ARB or IWMB, their magnitude can be estimated from the study by Choate and colleagues (2005) to dwarf the expected reductions from strategies 1 and 3. In fact, if current reduction goals from strategies 1 and 3 were targeted by strategy 2, most of the reductions could be achieved with net savings for each affected firm, and all 4MMTCO2 reductions could likely be achieved while still having net savings at the industry level (summing costs and benefits of all affected landfills).

Finally, other benefits from the regulation, such as tax breaks, will further alleviate cost burdens or enhance benefits. On-site recovery systems can lower energy and treatment costs and can reduce liability and insurance costs (Aseltine, McRea, Modi, Shukla, Sullivan, 2006). Safety measures, once seen as onerous, are now being undertaken willingly by SWM giants (Standard and Poor's, 2006).

As internal cost effectiveness becomes increasingly critical, these previously neglected resources become more important to profitability, growth, and competitive advantage.

Assuming that strategies 1- 3 result in some net costs, a second issue relates to firms' ability to manage costs. If these costs can be easily transferred, with little reduction in the quantity of waste services and landfill demanded, than they are of little threat to the industry. Ability to pass on costs is a function of consumer preferences and competition. Demand will be more inelastic when preferences are unresponsive to price and when there are few substitutes for a good or service. As seen earlier in the report, this is certainly the case for landfill and SWM in general. Demand for waste services is inelastic due to inflexibility of waste production and limited waste service substitutes. Moreover, due to a lack of viable disposal substitutes for landfill as an input into the production of waste services, waste companies' derived demand for landfill is very inelastic.

The restricted nature of competition within the landfill industry should also enhance the ability to pass on costs, as firms for whom regulation has less of an impact on cost structure will not necessarily be in intense competition with those for whom regulation is more impactful.

Trends towards industry consolidation continue even as overcapacity disappears. Interestingly, regulation should only accelerate consolidation. The Resources Conservation and Recovery Act of 1976 required installation of gas control equipment, and resulted in a tripling of US average landfill capacity as large landfills replaced small (Standard and Poor's, 2006). Though nothing near so dramatic will occur in this case, one would expect at least a slight to moderate effect. This effect could be mitigated through carbon caps, as smaller firms who faced dramatically higher costs and lower revenues could acquire carbon permits instead of upgrading technologies.

Finally, even if firms could not avoid internalizing a portion of costs, this would not likely significantly alter production decisions. California's landfills remain clustered around urban centers despite the fact that regulation costs have been higher in much of California than in neighboring states for some time. Today's focus on fuel cost efficiency as key to long run profitability only reinforces the attraction to locate near markets. Finally, it is relevant that even if landfills became less profitable, they would still be an essential input into the very profitable SWM industry.

In summary, whether revenues for any given firm increase more than costs will be a function of the technology used, scale of operations, indirect cost savings, and government incentives. If there are net costs it is likely that firms will be able to share these costs with consumers, if not transfer the burden to them completely. This is due to inflexible demand and monopolistic conditions. Regulation will enhance economies of scale, having a greater affect on average than marginal costs. Larger firms

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should have lower average costs and higher revenues, which should lead to a less competitive environment as smaller firms operating closer to the margins, with less disposable income, will struggle to manage costs. Finally, the attachment to markets should keep most waste in California. It is essential to qualify these general conclusions by noting again the "fragmentation" of waste services, where various contexts of SWM could lead to diametric outcomes in any given case.

As California's primary methane producer, landfills are not only significant in the fight against global warming in general, but are the critical component of any policy attempting to regulate non-Co2 greenhouse gases, especially due to associated low costs and even savings.

1.25.2 Scenario Description:

Anaerobic decomposition of buried refuse and other solid waste produces methane, a GHG with relatively high Global Warming Potential (GWP). In landfill systems where these materials are concentrated, this gas can be captured with digester technologies and dissipated by burning in flares or power generation. The objective of this scenario is to assess the economic effects of promoting such capture and gas recycling strategies (e.g. for sale or on-site electricity generation).

1.25.3 Modeling Approach:

For Landfill Management, we have data on eleven scenarios, depending on the scale of operation covered and the retention strategy:

Retention for gas recycling only – four scenarios

<u>Scale by Landfill Capacity in Short Tons (WIP)</u>

1. >1,000,000	Direct Gas
2. <1,000,001	Direct Gas
3. <500,001	Direct Gas
4. <400,001	Direct Gas

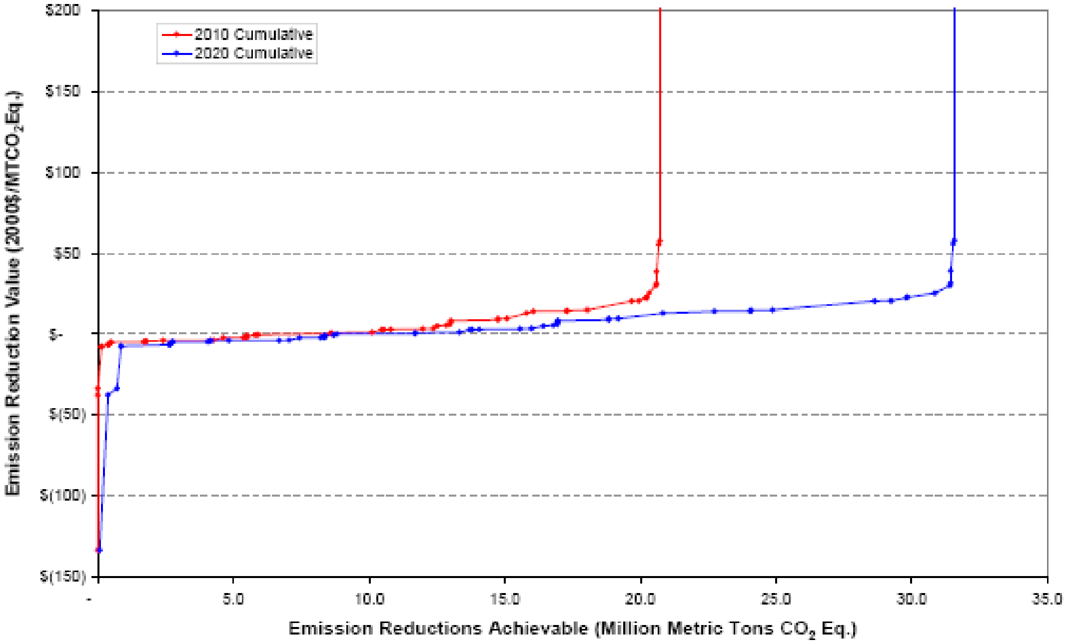
Gas capture and electricity generation – seven scenarios

Scale by Landfill Capacity in Short Tons (WIP)

5. >1,000,000 Electricity
6. <1,000,001 Electricity
7. <500,001 Electricity
8. <400,001 Electricity
9. <300,001 Electricity
10. <200,001 Electricity
11. <100,001 Electricity

The moderate scenario includes the first five measures above, while the ambitious scenario includes all eleven.

Figure 1.25.4: Marginal Abatement Curve Estimates for Measures to Reduce Non-CO2 Gases



Source: ICF:2005.

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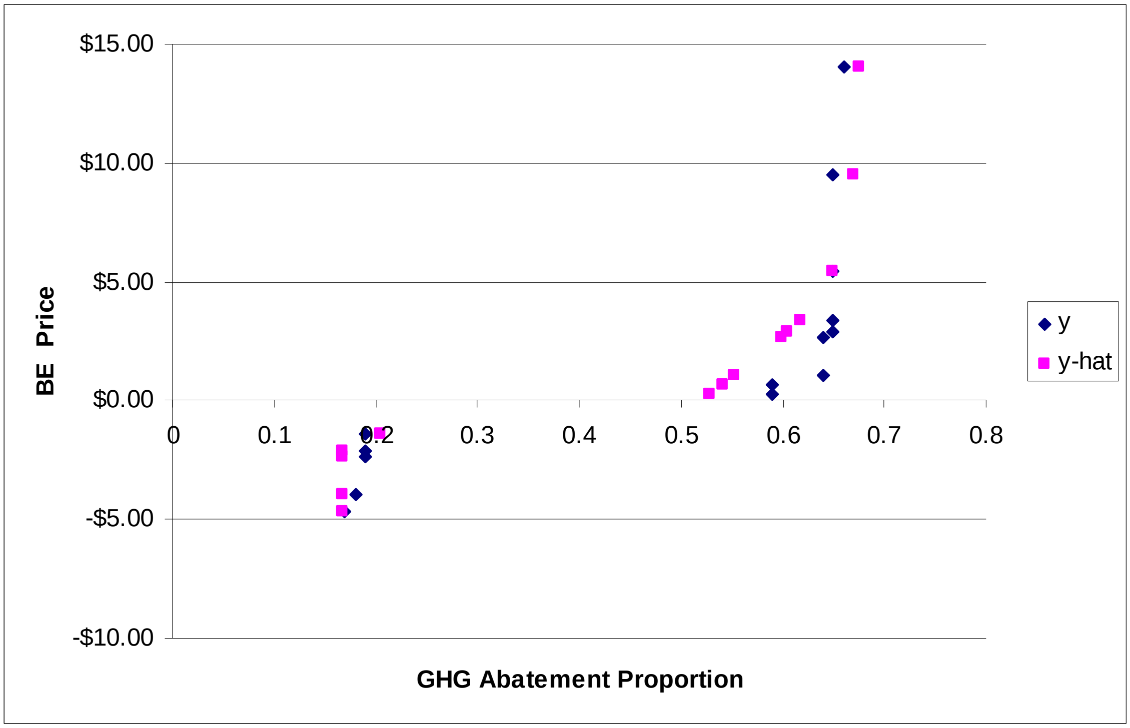
Figure 1.25.5: Estimated Discrete and Continuous MACs for Landfill Management



Source: ICF:2005 and author's estimates.

The model simulates these adoption strategies with three component adjustments:

Landfill firms incur costs in the form of Construction services to adapt their operations.

Landfill firms who generate electricity deliver this to the electricity grid. For simplicity, we also assume they continue meeting their own electricity needs from the same grid.

Landfill firms who retain gas use this to offset their demand from natural gas utilities.

These three components represent one cost, one revenue source, and one operational savings. From the data we have available, the balance between these varies between individual operations, but is positive across the industry. In the present simulations, we have chosen to combine the different scale scenarios to represent an industry-wide strategy. In this case, costs and benefits that might be incident

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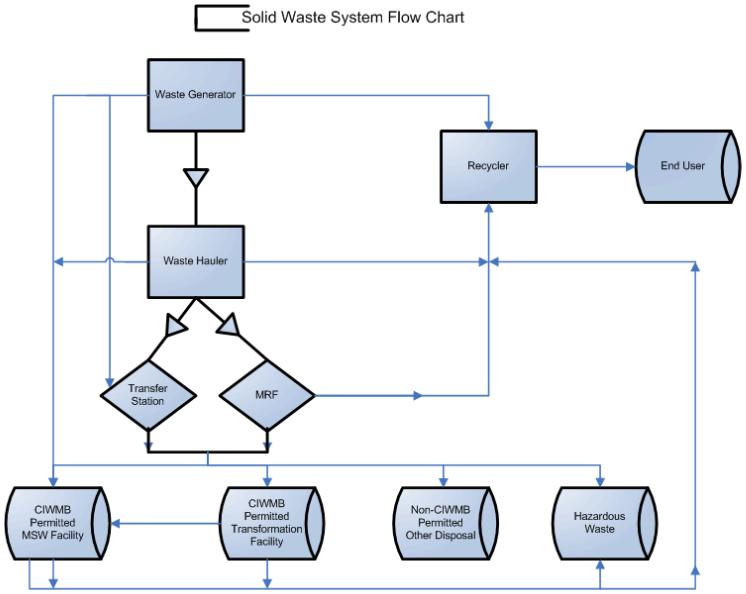
on individual firms are aggregated, and the result is a positive adoption incentive for the industry. Implicit in such a scenario is the assumption that within industry compensation schemes can be devised, either by private industry participants or policy makers using fees and subsidies, that permit the net social benefits of the policy to be realized by redistributing plant-level costs and benefits. In practice, such incentive pooling can arise from a combination of redistribution schemes and industry consolidation.

1.25.4 Data Sources and Description:

The ICF (2005a) report provides our baseline data for this scenario, with comparison reference to the international MAC data, and we calibrate abatement using the MAC framework.45 Methane emissions are measured in CO2 equivalents, the demand for abatement technology is directed at the construction sector, captured gas is consumed in the sector (resulting in savings on electricity expenditures) and self-generated electricity is metered out to utilities.

Figure 1.25.6: Solid Waste System Flow Chart



(Solid… Chart)

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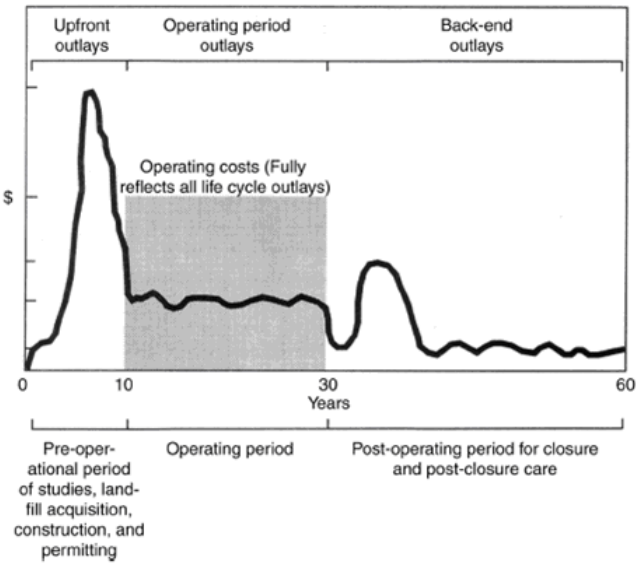
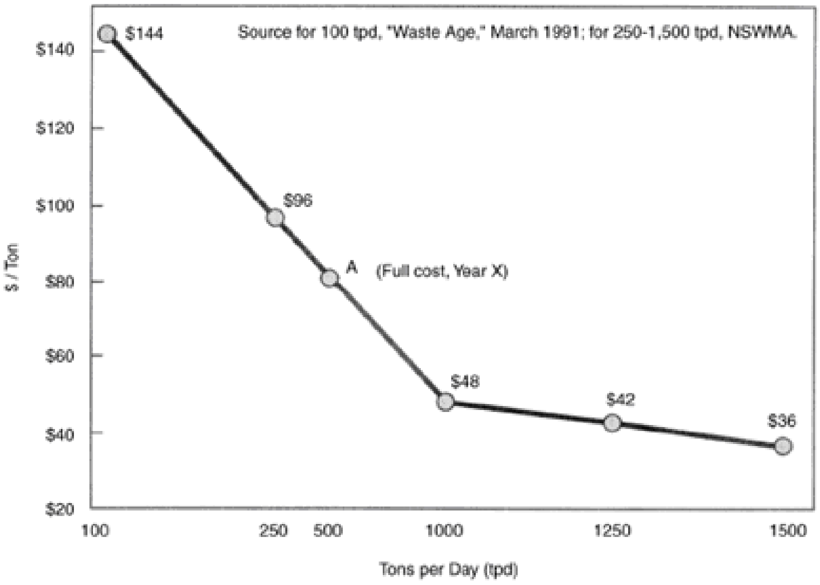
[45] Compare also EPA (1999).

Figure 1.25.7: Landfill Life-cylce Outlays and Costs



Source: U.S. Environmental Protection Agency, *Full Cost Accounting for Municipal Solid Waste Management: A Handbook* (530-R-95-041), 1997, exhibit 4-1, p. 29.

Figure 1.25.8: Economies of Scale at Landfills



ource: U.S. Environmental Protection Agency, *Full Cost Accounting for Municipal Solid Waste Management: A andbook* (530-R-95-041), 1997, exhibit 4-1, p. 29.

Figure 1.25.9: Disposal and Diversion

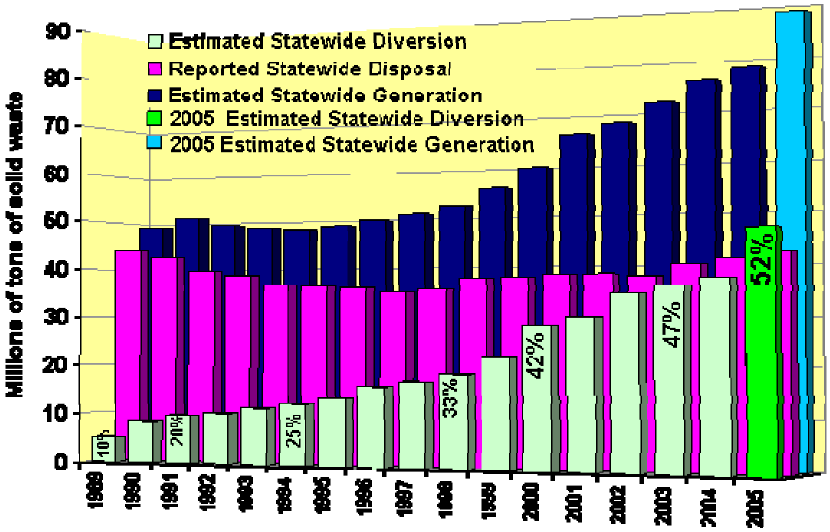
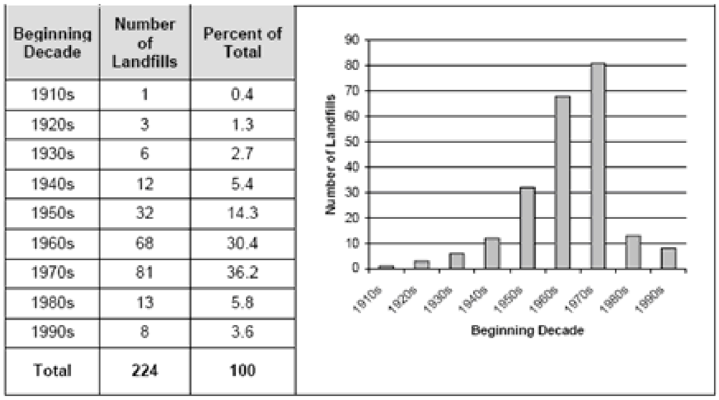


Figure 1.25.10: Distribution of Landfill Age



Beginning Decade	Number of Landfills	Percent of Total
1910s	1	0.4
1920s	3	1.3
1930s	6	2.7
1940s	12	5.4
1950s	32	14.3
1960s	68	30.4
1970s	81	36.2
1980s	13	5.8
1990s	8	3.6
Total	224	100

(Landfill… Landfills, 2003)

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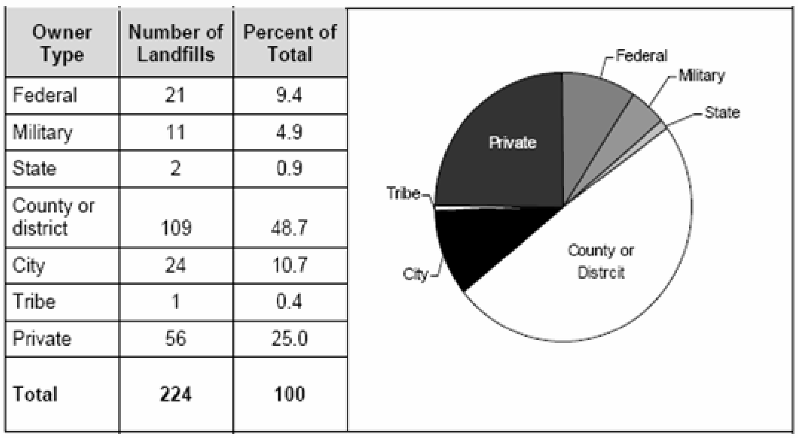
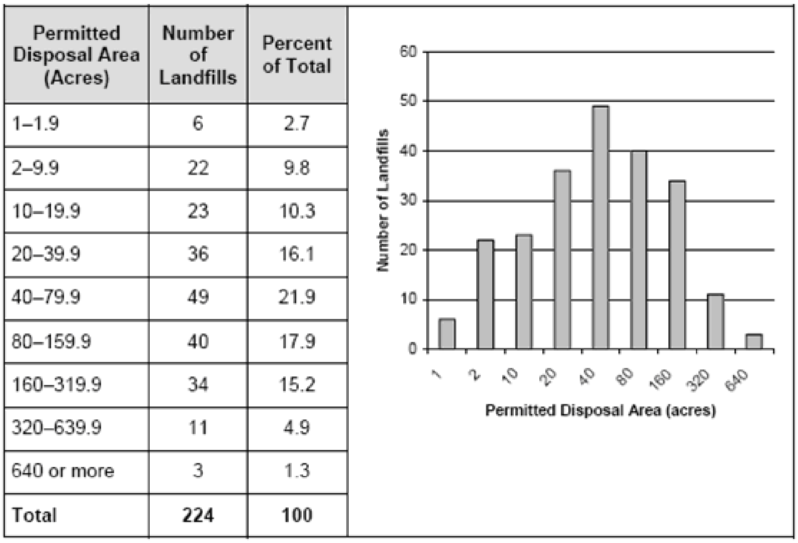
Figure 1.25.11: Distribution of Owner Type



Owner Type	Number of Landfills	Percent of Total
Federal	21	9.4
Military	11	4.9
State	2	0.9
County or district	109	48.7
City	24	10.7
Tribe	1	0.4
Private	56	25.0
Total	**224**	**100**

(Landfill… Landfills, 2003)

Figure 1.25.12: Distribution of Permitted Disposal Area



Permitted Disposal Area (Acres)	Number of Landfills	Percent of Total
1–1.9	6	2.7
2–9.9	22	9.8
10–19.9	23	10.3
20–39.9	36	16.1
40–79.9	49	21.9
80–159.9	40	17.9
160–319.9	34	15.2
320–639.9	11	4.9
640 or more	3	1.3
Total	**224**	**100**

(Landfill… Landfills, 2003)

Figure 1.25.13: Permitted Disposal Volume

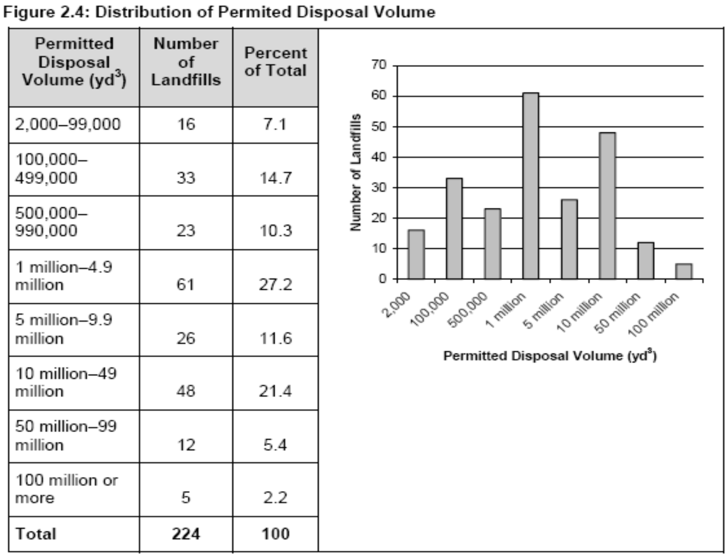
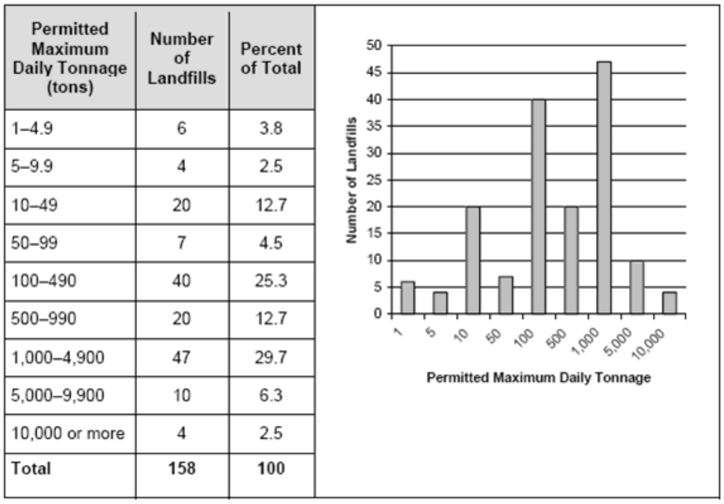


Figure 2.4: Distribution of Permited Disposal Volume

Permitted Disposal Volume (yd^3)	Number of Landfills	Percent of Total
2,000–99,000	16	7.1
100,000–499,000	33	14.7
500,000–990,000	23	10.3
1 million–4.9 million	61	27.2
5 million–9.9 million	26	11.6
10 million–49 million	48	21.4
50 million–99 million	12	5.4
100 million or more	5	2.2
Total	**224**	**100**

(Landfill… Landfills, 2003)

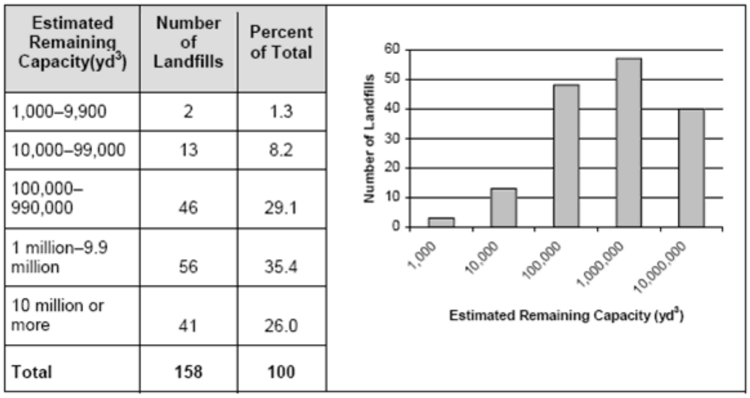
Figure 1.25.14: Distribution of Permitted Maximum Daily Tonnage



Permitted Maximum Daily Tonnage (tons)	Number of Landfills	Percent of Total
1–4.9	6	3.8
5–9.9	4	2.5
10–49	20	12.7
50–99	7	4.5
100–490	40	25.3
500–990	20	12.7
1,000–4,900	47	29.7
5,000–9,900	10	6.3
10,000 or more	4	2.5
Total	**158**	**100**

(Landfill… Landfills, 2003)

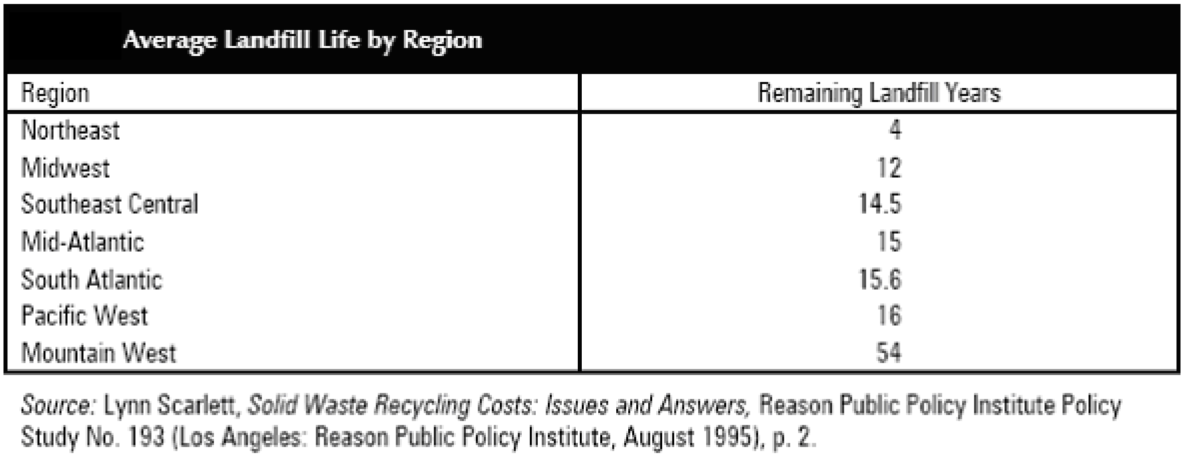
Figure 1.25.15: Distribution of Estimated Remaining Capacity



Estimated Remaining Capacity(yd^3)	Number of Landfills	Percent of Total
1,000–9,900	2	1.3
10,000–99,000	13	8.2
100,000–990,000	46	29.1
1 million–9.9 million	56	35.4
10 million or more	41	26.0
Total	**158**	**100**

(Landfill… Landfills, 2003)

Figure 1.25.16: Average Landfill Life by Region



Average Landfill Life by Region

Region	Remaining Landfill Years
Northeast	4
Midwest	12
Southeast Central	14.5
Mid-Atlantic	15
South Atlantic	15.6
Pacific West	16
Mountain West	54

Source: Lynn Scarlett, *Solid Waste Recycling Costs: Issues and Answers,* Reason Public Policy Institute Policy Study No. 193 (Los Angeles: Reason Public Policy Institute, August 1995), p. 2.

(Landfill… Landfills, 2003)

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Figure 1.25.17: Geographic Distribution of Estimated Remaining Capacity

(Landfill… Landfills, 2003)

Figure 1.25.18: MACC for Methane Emissions in California Landfills, DR= 4 percent and TR= 0 percent

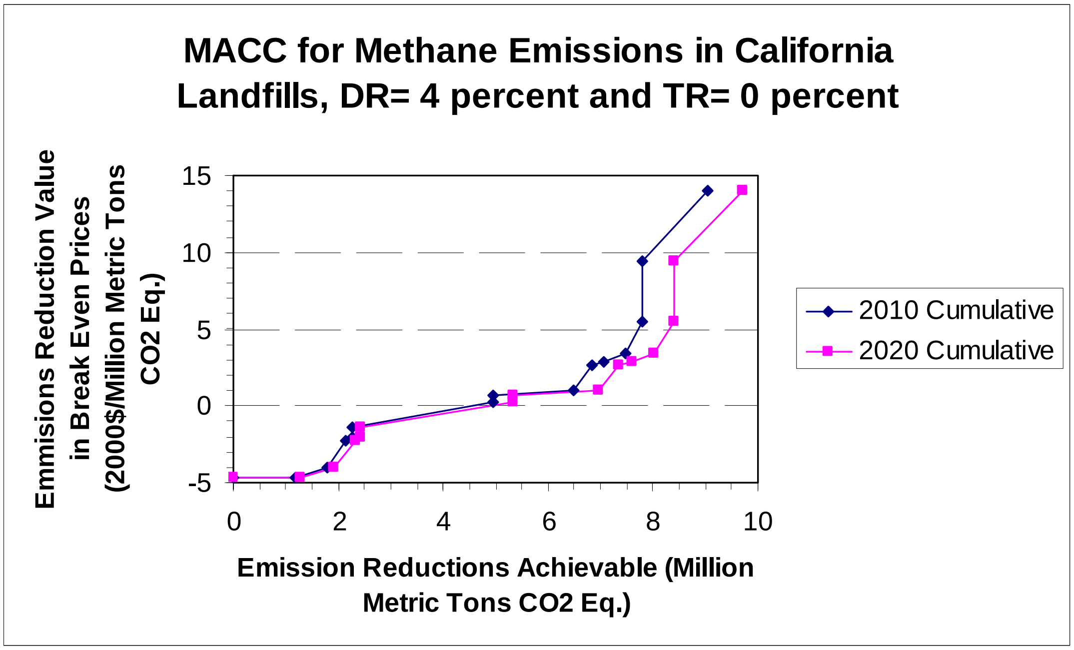
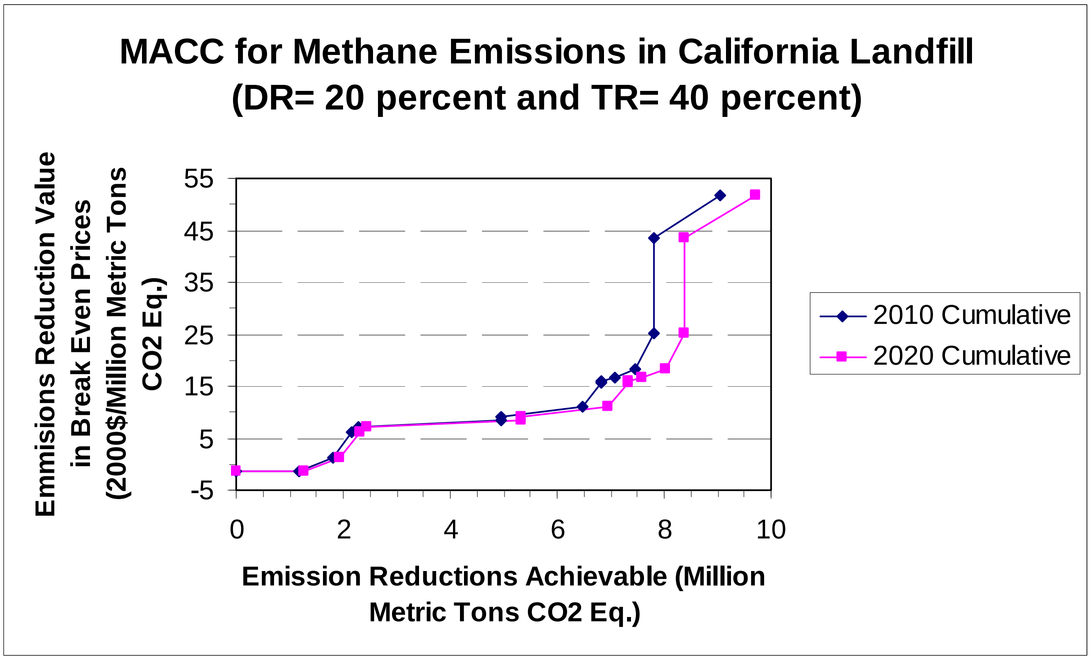


Figure 1.25.19: MACC for Methane Emissions in California Landfills, DR= 20 percent and TR= 40 percent



1.26 Afforestation

1.26.1 Sector Analysis

Approximately 60 percent of carbon stored in the terrestrial ecosystems is contained by forest ecosystems (Streck 2006). Another source estimates that 80 percent of global carbon is sequestered in soils or forests (Schneider 2006). This carbon is accounted in four basic pools: soil, ecosystem, standing trees, and products after harvest (Lee 2005). One form of carbon sequestration as suggested by the AB32 policies is afforestation of marginal rangelands. In California, Winrock estimates that up to 13.34 million acres of rangeland are potentially available for afforestation throughout the state. In addition, it is estimated that for every ton of carbon sequestered in forest biomass, 3.667 tons of CO_2 is removed from the atmosphere (Cornelis 1999). In this report, I focus on the afforestation potential in California and its implications for the AB32 policy.

Production Statistics

Input costs associated with Afforestation:

The costs associated with afforestation/reforestation are many: opportunity costs, planting and conversion costs, measuring and monitoring costs, and maintenance costs. Due to the fact that lands potentially viable for afforestation are rangelands, the profitability per hectare of cattle ranching in CA represents the opportunity cost of afforestation. The profit of any given acre of rangeland is proportional to the forage production which determines its carrying capacity. According to Winrock (2004), low-producing rangeland (~100 lbs. of forage DM per acre, requires 95 acres to support one head of cattle per year): the annual per acre profitability is estimated to be $0.71 (i.e., $67.50/ 95); and High-producing rangeland (~2,000 lbs. of forage DM per acre, requires 4.75 acres to support one head of cattle per year) the annual per acre profitability of high-producing rangeland is estimated to be $14.22 (i.e., $67.50/ 4.75, Table 1.26.1)

Planting and conversion costs are the estimated cost for establishing tree planting on rangelands in California and are on average $450 per acre. These costs vary from $300 to $600 per acre, and are determinate upon factors such as moisture, soil texture, and slope of the site.

Measuring and monitoring costs are the costs of measuring the carbon production over the life of the activity. These costs are on average at an estimated $2.5 per hectare per year. The factor affecting cost include which pools are measured and monitored, frequency of monitoring, area, and whether the lands are contiguous or dispersed. Economics of scale exist for these measurement and monitoring costs, where the costs are higher for smaller activities.

Maintenance costs are incurred for a five year period from the beginning of the activities. They ensure that enough tree seedlings survive to generate a well-stocked stand and are estimated to be approximately $20/ha.yr during the first five years. These costs include the ones of replanting seedlings that have died, weeding or herbicide application, fertilizing, adequate fencing to control livestock incursion, and fire prevention. Fire prevention is estimated to be from $40 to $100 per acre, dependent on the average slope and proximity to roads at a given site. Fire prevention costs include the costs of burning the land prior to tree planting activities to reduce the fuel load.

Another cost that is often ignored is transaction costs—these are the costs of capturing and protecting property rights and transferring them from one agent to another (Cornelis 2002). Pejovich (1995, 84) states that these are “the costs of discovering exchange opportunities, negociating contracts, monitoring and enforcing implementation, and maintaining and protecting institutional structure”

Table 1.26.1: Revenue and costs associated with cattle ranching in California. [46]

Economics of California Ranching			
Revenue			
Total		**$/cow**	**Assumptions**
Calf	**$500.00**	**$425.00**	**85% wean rate**
Cull cows	**$450.00**	**$67.50**	**15% cull rate**
Total Revenue			**$492.50**
Costs in $/cow			
Pasture		**$111.00**	**(Including cost for bulls - 5% of herd)**
Supplemental feed		**$145.00**	**(Including replacement heifers - 15%)**
Other operating and fixed costs			**$169.00**
Total Costs			**$425.00**
Mean Annual Profit per Cow (Revenue – Costs)			**$67.50**

Output:

The main output of concern with afforestation/reforestation is the potential for carbon sequestration. The total amount of carbon that could be sequestered by afforesting grazing lands and changing forest management over a 20 year period is about 894 MMT CO_2, at a price of $13.6/ MT CO_2

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[46] Winrock (2004). Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California. Winrock International, for the California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-04-068F

(Table 1.26.2). Approximating this total amount to an annual rate, results in about 45 MMT CO_2/ yr (Winrock 2004).

Outside of carbon sequestration, the benefits to society include food, fiber, shelter, watershed services, biodiversity, recreation, and aesthetic qualities, climate mitigation (carbon sequestration) (Murray 2004).

Table 1.26.2: Summary of the quantity of carbon (million metric tons CO_2 [MMT CO_2]) and area (million acres) available at selected price points

Activity	Quantity of C—MMT CO_2			Area available—million acres		
	20 years	40 years	80 years	20 years	40 years	80 years
	Forest management					
	Lengthen rotation					
≤$13.6 (discounted C)	3.47	--	--	0.31	--	--
≤$13.6 (undiscounted C)	2.16	--	--	0.30	--	--
	Increase riparian buffer-width					
≤$13.6	3.91 (permanent)			0.044		
	Grazing lands					
	Afforestation					
≤$13.6	887	3,256	5,639	12.03	17.79	20.76
≤$5.5	345	3,017	5,504	2.72	14.83	19.03
≤$2.7	33	1,610	4,569	0.20	5.68	13.34

Notes: Carbon tradeoffs are given for several classes of activities on existing rangelands and forestlands over 20-year, 40-year, 80-year, and permanent (forest management—riparian buffer) durations.[47]

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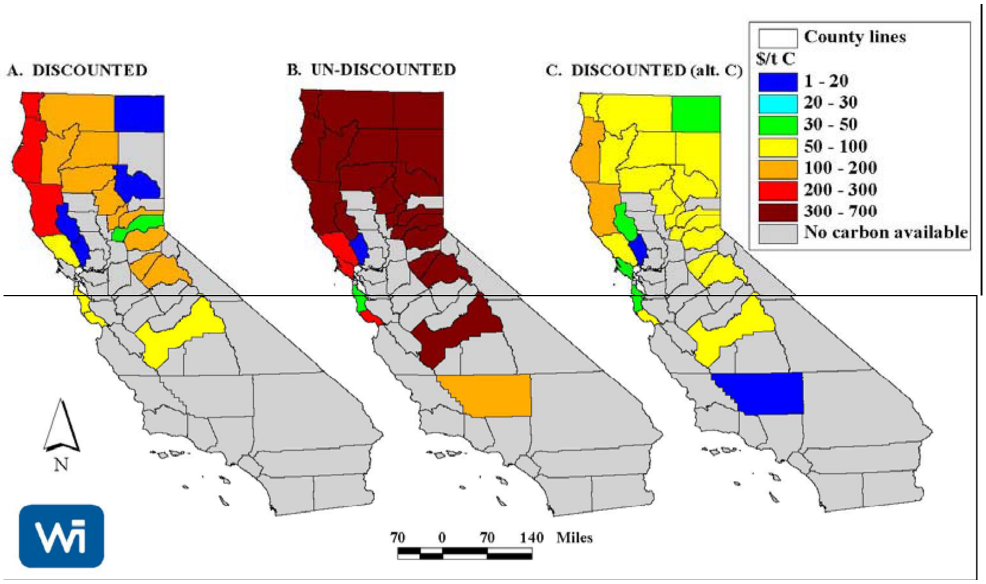
[47] Winrock (2004). Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California. Winrock International, for the California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-04-068F

Technology

There exists potential to increase rotation ages to enhance carbon sequestration because many tree species are still growing when harvested. Winrock states that the largest potential source of carbon from forest management is for lengthening rotation by five years. This would cost less than \$13.60/$MTCO_2$ and provide 2.61 to 3.91 $MMTCO_2$ (dependent on whether the carbon is discounted or not). Although, by increasing the rotation ages, there are financial implications for landowners when delaying the next rotation.

Figure 1.26.1: Distribution, at the county scale, of the cost to sequester carbon (in \$/metric t C) via lengthening the forest rotation time by 5 years for two methods of discounting carbon (A. and C.) and for undiscounted carbon (B.). [48]



When lengthening the forest rotation by five years, counties in California with the cheapest carbon do not produce the highest quantities of carbon. The highest quantities of potential carbon sequestration by rotation lengthening are located in the north coast counties, although these places also have the most expensive carbon. By lengthening rotation, the costs tend to be lower when the emissions from

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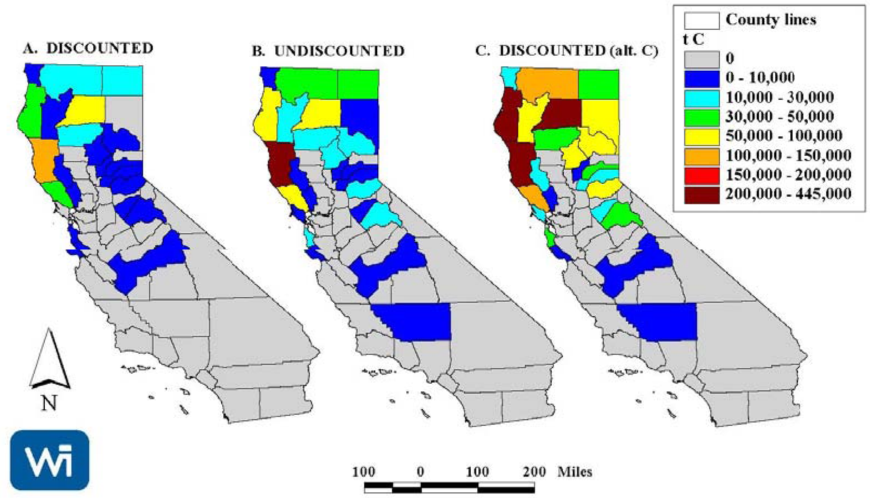
[48] Winrock (2004). Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California. Winrock International, for the California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-04-068F

the initial harvest are held off to future periods, because it creates additional carbon benefits in early periods (Figure 1.26.1 and Figure 1.26.2).

Figure 1.26.2: Distribution, at the county scale of resolution, of the potential amount of carbon (metric t C) that could be sequestered on all forest lands by lengthening the forest rotation time by 5 years for two methods of discounting carbon (A. and C.) and for undiscounted carb



For afforestation of rangelands, longer rotation period lowers carbon costs, but also landowners may be more hesitant to commit to land projects that are lengthier. Afforestation of rangelands provides the most carbon at the least cost at less than \$2.7/MT CO_2. This equates to around 33 MMTCO2 at 20 years or 4.57 billion MTCO2 at 80 years. The counties with the least expensive carbon from afforesting rangelands would be the same counties that could potentially sequester the most (Figure 1.26.3) (Winrock 2004).

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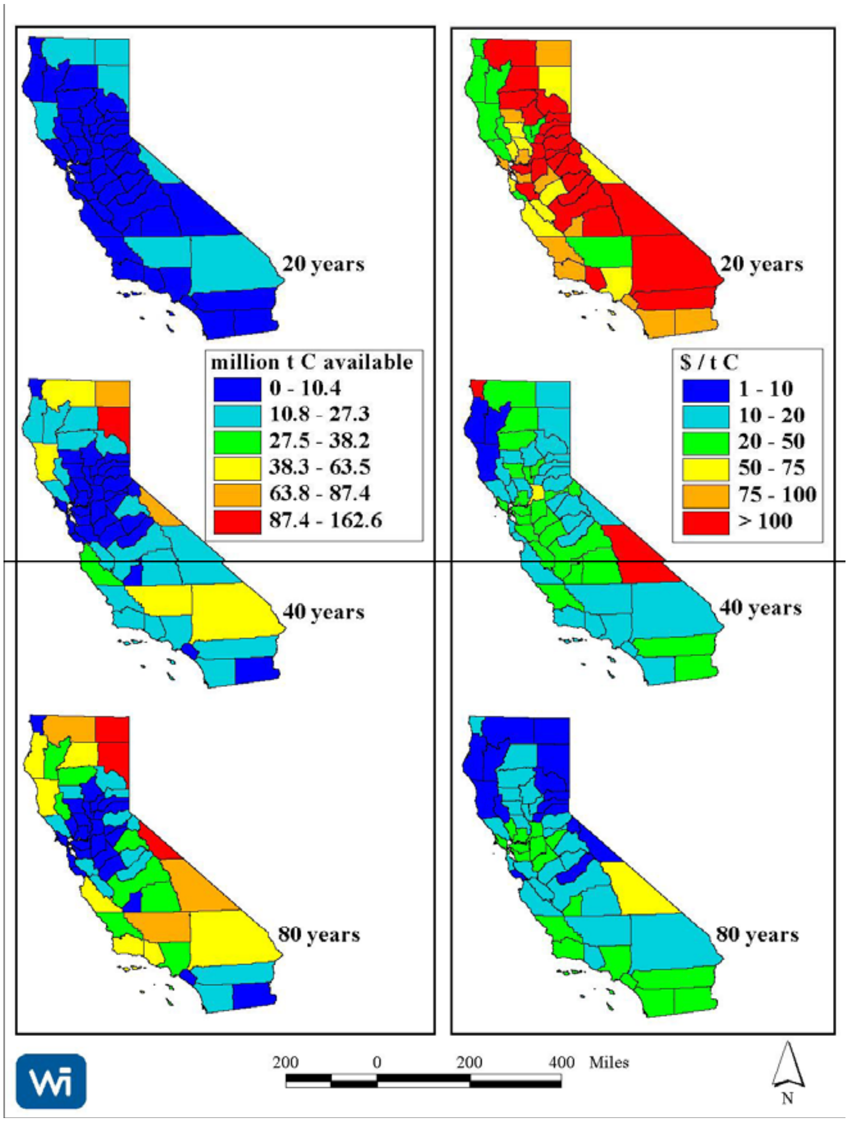
Figure 1.26.3: Total carbon sequestered by afforestation of rangelands (metric tons; left) and area-weighted average cost per metric ton of carbon (to convert to $/ metric t CO2, divide by 3.6) and after 20, 40, and 80 years.



From Stavins, 2000

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Perspectives

Carbon sequestration in the agricultural and forest sector is estimated to potentially offset about 3-15% of US projected green house gas emissions (or 8,000 and 10,200 MMT of CO2 equivalent) (Lee 2005).

Sources of uncertainty that currently exist include the effects of global warming, discount rates, permanence, and leakage. Global warming may affect forests, perhaps changing location of land viable for afforestation or even productivity. Discount rates will affect the present value of carbon. Also permanence, or the question of how long will the carbon be sequestered, produces uncertainty. Finally, leakage, or the change in activities or behavior outside of the project area that partially or totally offsets the climate gains of the project, has implications for the affects of afforestation beyond the local scope.

Prognosis for Policy Response and Adjustment

The AB32 policies suggest the following strategies to encourage afforestation and the

- establishing a new statewide goal of reforesting 250,000 acres on federal lands; seeing $30 million annually, or $300 million in bond funds to meet these targets
- establishing a long-term loan program to fund private land reforestation
- establishing a multi-sector market-based program where reforestation projects can be included as offsets in a broader, multi-sector climate change market-based program
- establishing a state-owned carbon bank, modeled after Oregon's Climate Trust, as part of a market-based program

It is in my belief that implementing these strategies will be a cost-effective way of reducing carbon emissions. Throughout the state of California, Winrock estimates that up to 13.34 million acres of rangeland are potentially available for afforestation, making it plausible goal on behalf of the AB32 policies to reforest 250,000 acres on federal lands establishing a new statewide goal of reforestation. Most all studies, such as in Plantinga et. al., 1999 and Lee et. al. 2005, suggest that the costs of afforestation programs compare favorably to costs of alternative mitigation approaches are are a cost-effecitve strategy for offsetting CO_2 emissions.

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The latter AB32 policies suggest setting up a market-based program where reforestation projects can be included as offsets in a broader, multi-sector climate change market-based program. Streck suggests that crediting countries for sinks would allow them to implement cost-efficient compensation measures that would let them off the hook in respect of more complicated energy projects. Permanence of temporary credits and leakage may arise as problems to carbon banking.

The transition to a market-based system will most likely be a relatively smooth transition. In van Kooton's study on carbon sequestration market in Canada, it was found that 75% of survey respondents indicated a willingness to create carbon offsets if they could somehow sell carbon credits or if they were adequately compensated. Landowners expressed preference for tree-planting contracts over a pure market mechanism that would enable them to sell offsets without interference. They were reluctant to enter into contracts with environmental NGO's and prefer to work with government or even large companies that need to purchase carbon offsets. The size of the credits is determined by the increases in tree biomass, crop residues and soil organic matter brought about by the action. For smooth transition and implementation of the policies, the government must adequately compensate farmers for the switch to afforestation in California.

1.26.2 Scenario Description:

Restoration of native tree cover in California. The basic objective is to create a large carbon sink inside the state by converting rangeland to long term forest resources. In the present scenario, we consider only the cost of establishing the forests and their benefit in terms of carbon capture. The time horizon used in this study is too short to consider GHG effects and revenues from timber harvest and sale.

1.26.3 Modeling Approach:

Conversion of rangeland is assumed to be the result of investment decisions by the Cattle sector, purchasing services from the Forestry sector in an amount equal to independent estimates of annualized investment and O&M costs (see below). Mitigation of GHG is assumed to be phased into a steady state (based in independent estimates) over a 15 year time horizon. In addition to this basic framework, we add the following assumptions:

1. Capital markets efficiently annualize all costs and benefits at steady state levels

2. No timber revenue inside the current time horizon (2020)

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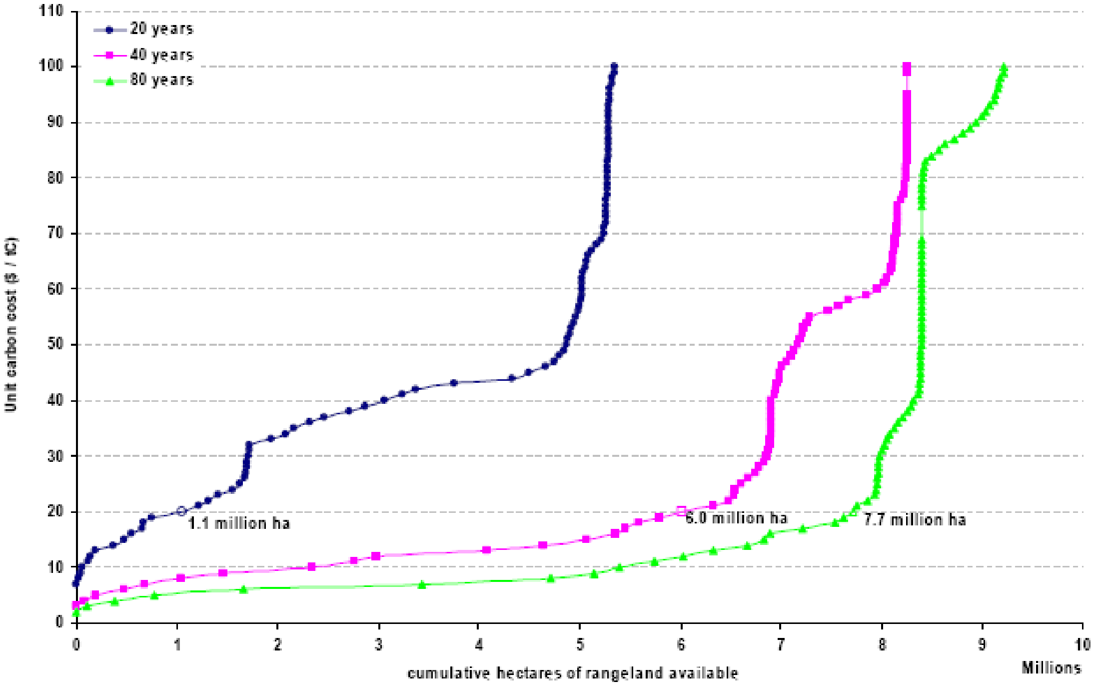
1.26.4 Data Sources

The primary data include Marginal Abatement Cost (MAC) curves estimated by independent consultancies for the California Energy Commission.[49] The main resource for our current estimation is a report by Winrock International (Winrock:2004b), who produce extensive bottom-up data on sequestration potential from afforestation.

Figure 1.26.4: Marginal Abatement Curve Estimates for Afforestation



Source: Winrock:2004b.

Generally speaking, we applied these technologies in two cumulative scenarios, aggregating individual MACs across the industry.[50] As in other sectoral policies, the first was a Moderate scenario with aggregate GHG mitigation approximating AB32 (2005) estimates. The more Ambitious scenario incorporated all three afforestation approaches. The costs given in the Winrock report are shown in

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[49] MACs are surveyed in many sources in the economic literature. See, e.g. Baumol and Oates (1992) or McKitrick (1999).

[50] The break-even carbon price is the value per unit of avoided GHG emissions (generally per metric ton of CO_2 equivalent) at which present value lifetime benefits of GHG mitigation measure equal the present value of lifetime costs. Often this is calculated as the difference of the present value of costs and benefits divided by lifetime GHG savings.

`

Figure 1.26.4 in year 2000 dollars. In order to make these costs compatible with the core economic data used by BEAR, we converted results from the 20 year scenario (leftmost MAC curve in the figure) to 2003 dollars using a GSP deflator series compiled by the California Department of Finance (2005) from U.S. Bureau of Economic Analysis data. This deflator was applied to the costs for conversion, maintenance, measurement and monitoring. Note that the longer term scenarios in Figure 1.26.4 indicate much higher mitigation potential. We believe these deserve further examination, but have chosen a time horizon conforming to our economic scenarios for the present analysis.

Annual opportunity costs, meaning the annual foregone profits from cattle grazing, are discussed in the report but are not shown for the specific break-even levels for which other data are given. These values were derived by balancing the equation for the break-even prices with the other parameters provided in the report. Expenditures for land conversion, maintenance, measurement, and monitoring are assumed to flow from the livestock cattle sector to the forestry sector.

Finally, we have assumed the mitigation benefits of afforestation phase in linearly over the first ten years (2005-2015). In reality, implementation will depend on public and private actions and the biology of carbon update may not be linear from time of planting.

1.27 HFC Reduction Strategies

An important category of GHG emissions, hydroflourcarbon (HFC) gases are emitted in association with fabrication and use of refrigeration and air conditioning systems. Many of these gases have relatively high global warming potential, and they constitute an important target group for mitigation policy.

The scenarios considered here cover refrigerant and cooling technologies in motor vehicle air conditioning systems (MVACs), with the overall objective of assessing economic effects of reducing HFC gas emissions. These emissions may not be large in volumetric terms, but the high global warming potential (GWP) values of HFC makes their mitigation a priority and a source of substantial CO2 equivalent mitigation. In the present analysis we consider eight HFC scenarios:

1. Improved HFC-134a in MVACs
2. HFC-152a in MVACs
3. CO2 for New MVACs
4. Replace DX w/ Distributed System

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5. Secondary Loop
6. Ammonia Secondary Loop
7. Leak Repair
8. Recovery (Refrig)

1.27.1 Data Sources and Description

The HFC scenarios are calibrated to bottom-up data produced for the California Energy Commission by ICF Consulting (ICF:2005a, b). This report assessed the cost and mitigation potentials of seven different categories of abatement measures related to the reduction of non-CO2 GHGs. Data for several other measures incorporated in BEAR, as described below, were also drawn from this report. The measures shown here were examined for the Pavley analysis (CARB: 2004), a report prepared in response to Assembly Bill 1493. This bill adopted GHG mitigation targets for automobiles sold in California. However, the CARB report does not provide individual cost information on the three measures in this set. ICF used the most current industry data available, which may differ from the Pavley analysis. ICF projects very little penetration of these technologies by 2010 but some appreciable impact by 2020. Expenditures are assumed to be borne by the automobile manufacturing industry for increased cost of equipment from air conditioning equipment providers. Detailing estimates of adoption costs and mitigation potential are given in the Refrigeration-AC spreadsheet of BEAR_Data.xls.

The information provided in the ICF report readily enabled the estimation of key data points needed for the BEAR model. Each section in the report, covering a different category of measures, includes a table of capital costs, annual costs, and annual benefits (where applicable) expressed in real 2000 dollars per annual metric ton of CO2 equivalent avoided. Four additional tables display the annual reductions and break-even prices (calculated using the discounted abatement stream) for each measure. The four tables show the results using two sets of financial parameters (private cost, with a 20% discount rate and 40% tax rate, and social, with a 4% discount rate and 0% tax rate) for two different years (2010 and 2020). For BEAR, the social cost tables were used. The product of expected annual reductions and the costs and benefits per ton yields the total capital outlay and total annual costs and benefits for each measure. As with the Winrock report, all costs and benefit figures in the ICF study were scaled from year 2000 dollars to real 2003 dollars.

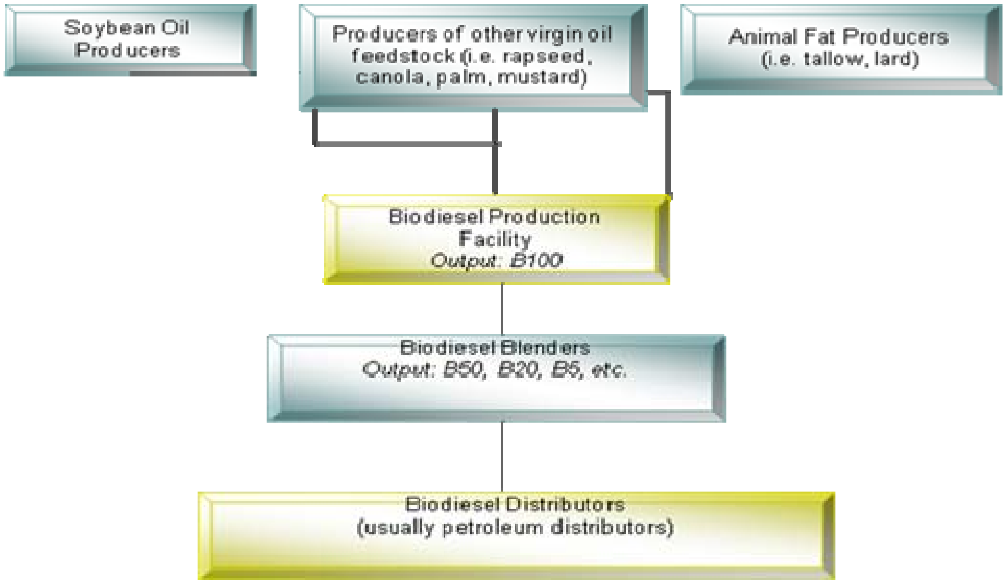
Cost and reduction potential for large stationary cold storage applications were also examined: distributed system coolers that use many compressors connected to a single cooling unit, secondary loop systems with a short coolant loop that exchanges heat to a secondary loop with cooling fluid, and a secondary loop with ammonia as the coolant. Two better practice measures were also analyzed: leak reduction in large stationary systems and greater recovery of refrigerant during servicing and disposal of small equipment. Costs for this measure are assigned to the wholesale trade sector and equipment revenues flow to the air conditioning equipment manufacturers.

1.28 Alternative Fuels - Biodiesel Blends

1.28.1 Sector Analysis

The biodiesel industry has emerged in the last two decades as a legitimate participant in the fuel provider sector. Since the establishment of the first industrial-scale plant in 1989, the industry has benefited from technology gains and fossil fuel reduction schemes in order to compete with the petroleum-based fuels. The product itself is biodegradable and non-toxic, and requires the use of a biological feedstock such as soybean oil. The following flowchart summarizes the primary players in the industry.

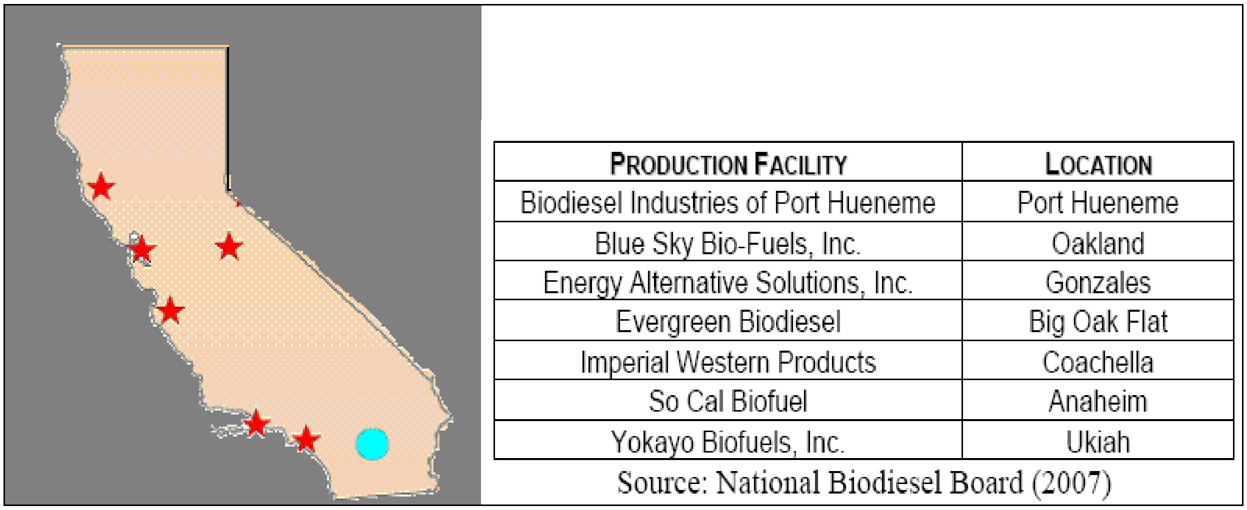
Figure 1.28.1: Biodiesel Industry Flowchart



At the initial level are the producers of the feedstock, although it is important to note that 91.5% of biodiesel comes from soybean oil (Urbanchuk 2006,2). The production of soybean oil is a two-step process – the soybean farmers grow and harvest the crop and soybean oil producers convert it to usable oil. The feedstock is subsequently sent to the biodiesel production facility, where alcohol and a catalyst is added to the oil to chemically produce pure biodiesel (B100) and glycerol. In the third stage, B100 is transported to the biodiesel blenders, where different diesel-biodiesel blends are created according to the demands of the clients, the biodiesel distributors.

The state of California currently has seven biodiesel production facilities. The eighth facility run by American Biofuels in Bakersfield, California burned down and has not been rebuilt. The most recent production plant, Blue Sky, began operating in February 2007. The primary consumers of California biodiesel include the federal government at national parks, cooperative units, fueling stations, and a few private companies.

Figure 1.28.2: Biodiesel Production Facilities in California



PRODUCTION FACILITY	LOCATION
Biodiesel Industries of Port Hueneme	Port Hueneme
Blue Sky Bio-Fuels, Inc.	Oakland
Energy Alternative Solutions, Inc.	Gonzales
Evergreen Biodiesel	Big Oak Flat
Imperial Western Products	Coachella
So Cal Biofuel	Anaheim
Yokayo Biofuels, Inc.	Ukiah

Source: National Biodiesel Board (2007)

Outline of Inputs

Inputs for Production of B100

The general reaction that produces biodiesel is an input of 100 pounds of oil and 10 pounds of methanol, producing 100 pounds of pure biodiesel and 10 pounds of the byproduct, glycerol (Howell 2006). The 10 pound of alcohol can be methanol or ethanol, but methanol is generally the more

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economical option. Furthermore, traces of alcohol are still left in the outputs, and therefore, the processing costs include equipment to remove the remaining alcohol from the glycerol.

Table 1.28.1: Variable Costs

Item	Cost (US$)
Soy oil (crude, degummed)	0.52/kg (0.236/lb)
Methanol	0.286/kg (0.130/lb)
Sodium hydroxide	0.617/kg (0.280/lb)
Electricity	0.05/kW h
Natural gas	4.80/thousand cubic feet
Plant operating labor	2 Persons/shift at $12.50/hour

Source: Haas (2004)

At a value of $0.236 per pound for feedstock soybean oil, the marginal cost of biodiesel was about $2.00 per gallon (Haas 2004). The single greatest contributor to this value was the cost of the oil feedstock, which accounted for 88% of total estimated production costs.

Table 1.28.2: Fixed Costs of a production plant:

Item	Cost \(US$, thousands)
Maintenance supplies	**1% of capital costs, annually**
General and administrative	**0.50% of capital costs, annually**
Wastewater treatment	**50,000/year**
Storage facilities (Oil storage tank, Biodiesel storage tank, glycerol storage tank)	**1,200**
Process equipment (reactor, wash tank, mixer, glycerol biodiesel separator)	**2166**
Utility equipment (cooling tower system, Steam generation system, electrical distribution system)	**403**

Source: Haas (2004)

The largest contributors to the equipment cost, accounting for nearly one third of expenditures, were storage tanks to contain a 25 day capacity of feedstock and product. The storage tanks for the storage of glycerol were also substantial, meaning that some firms may forgo the option of storing the byproduct.

To provide another perspective, the National Renewable Energy Laboratory performed its own study of the cost of biodiesel production in 2006, and found the costs to be significantly higher, at $2.69/gallon for biodiesel produced from soybean oil.

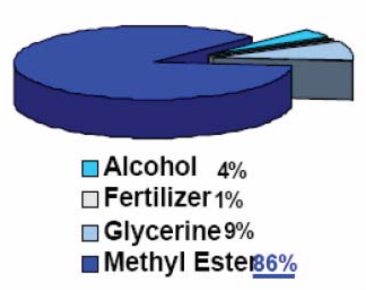
Table 1.28.3: Costs of Production

	Soybean Oil	Recycled Grease
Cost of Feedstock	$2.22	$1.09
Cost of Processing	$0.47	$0.47
Estimated Production Costs	$2.69	$2.69

Source: NREL (2006)

Outputs

Figure 1.28.3: Process Output Levels



Source: University of Illinois (2006)

Product Analysis

As depicted in the pie chart, 86% of the output from the chemical reaction is methyl ester, the chemical name for biodiesel. The fuel source is a light to dark yellow liquid, and the processed biodiesel in its pure form is denoted as B100.

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Although the output of the reaction is B100, the purified form of biodiesel is rarely sold. This is due to the fact that most diesel engine manufacturers do not recommend the use of B100 on most of their engines (see section 12). Instead, B100 is blended with diesel to form different combinations of the two fuels. Additionally, the tax credit benefit, discussed in section 11, extends only to mixed forms of biodiesel, including B99.9. This creates a disincentive for producers to sell B100.

Analysis of the Byproduct

Glycerol is a byproduct in the transesterification process, and also has key implications in the production of biodiesel, because it can assuage the production costs by $0.15/gallon (ARB 2005). Glycerol is a colorless, odorless chemical compound with a number of pharmaceutical applications including: in medical preparations as a means of improving smoothness and providing lubrication, as a laxative when introduced into the rectum, and as a substitute for alcohol, as a solvent that will create a therapeutic herbal extraction. Synthetic glycerol used to be manufactured from epichlorohydrin, but since the arrival of biodiesel, there has been a surplus of crude glycerol, and the price of glycerol has fallen (Pachauri 2006).

Production Statistics for a Representative Firm

Imperial Western Products, headquartered in Coachella, California, has recently integrated a biodiesel division to complement their primary services of manufacturing livestock feeds. They are the second largest production facility in California (behind BlueSky Biofuels in Oakland[51]), with a capacity of 8 million gallons per year (MMgy). The following data is from a phone interview with Curtis Wright, Operations Manager of IWP.

Inputs:

IWP calculates its marginal cost per gallon of biodiesel by breaking the costs into two groups: operating costs and oil costs. They estimate that each gallon of biodiesel requires about $0.50 to cover the labor and fixed costs. Imperial Western Products produces biodiesel from both soybean oil and recycled vegetable oil. “Soybean oil is selling for around 38 cents per pound delivered to Coachella. Used cooking oil is selling for 25 cents per pound delivered to Coachella. Both weigh about 7.6 pounds per gallon” (Wright 2007). Therefore, given that it takes 1.03 gallons of used cooking oil to make one gallon of biodiesel and 1 gallon of soy oil to make one gallon of biodiesel, IWP spends about

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[51] BlueSky Biofuels did not start producing until February 2007)

$2.89/gallon on biodiesel from soybean oil and $1.96/gallon on biodiesel. If you include the overhead costs (+$0.50) and the biodiesel tax (-$1 for soybean oil or -$0.50 for used cooking oil), then the final marginal costs are $2.39/gallon and $1.96/gallon.

Outputs:

IWP produces B100, but also provides blended mixtures of any combination, as requested by the petroleum distributors.

Clients:

Almost 90% of the company's clients are petroleum distributors. The rest are centrally fueled fleet users (construction companies, mines, cement companies, etc.) and cooperatives.

Greenhouse Gas Emissions

The purest form of B100 contains 10 percent oxygen by weight. Even after B100 is blended with diesel to form mixed blends used in diesel engines, the presence of oxygen in the fuel leads to a reduction in emissions of hydrocarbons (HC), carbon monoxide (CO), and particulate matter (PM) (McCormick 2006, iii). Despite these environmental benefits of biodiesel, a study by the EPA (2002) showed a 2% increase in Nitrous Oxide emissions (NO_x), and many states have subsequently considered banning the use of biodiesel in fear of the increase of NO_x.

In an attempt to set straight the nebulous effects of biodiesel on NO_x emissions, the National Renewable Energy Laboratory (2006) headed a study to evaluate the claims of the EPA. First, they found that post-2002 published engine testing studies "found an average change in NO_x from B20 to be 0.6%+- 2.0%" (NREL 2006), meaning that the results are statistically insignificant. In their own study, the researchers tested eight heavy-duty diesel vehicles, including three transit buses, two school buses, two Class 8 trucks, and one motor coach. On average, they reported that B20 caused PM and CO emission reductions of 16 and 17% respectively, and a reduction in HC emissions of 12% (relative to petroleum-derived diesel fuel). The most important finding was that NO_x emissions on average did not change (0.6% +- 1.8%), suggesting that the EPA's report of increases in NO_x emissions should be reconsidered.

A definitive conclusion about the relationship between NO_x and biodiesel has not been reached, but the most recent studies on the impact of biodiesel on emissions have all shown that the changes in NO_x due to biodiesel are not statistically significant. This uncertainty, nonetheless, is still an important factor considered in biodiesel policy debates, and serves an obstacle in the passage of pro-biodiesel initiatives.

Analysis of Current Technologies

If we simplify the production model to only include two input costs, the costs of oil and operating costs[52], then we can evaluate the potential efficiency gains from innovation that can drive down each of the two components of the costs of production.

The cost of oil ($\text{Price}_{\text{oil}}$ x $\text{Quantity}_{\text{oil}}$) depends on the quantity demanded of biodiesel, and the only available avenue by which biodiesel producers could achieve efficiency gains is producing more biodiesel with less oil. However, given the laws of thermodynamics, the outputs of the reaction are proportional to the inputs, and therefore, little can be done to produce more with a set quantity of inputs. The price of oil is determined by the market value, but technology gains in the soybean harvesting sector could lower prices.

The better part of innovative technologies in the industry aim at lowering the operating costs attributed to processing biodiesel (i.e. electricity, water, energy). The differences in choice of processing unit technologies can lead to differences in operating costs of about $0.10/gallon (Wright 2007). For example, American Biofuels in Bakersfield, California utilized the "continuous flow process technology," stating that it reduces the footprint needed for production, while also reducing maintenance and operational costs, capital construction costs and construction time" (Bryan 2004). The continuous flow process has displaced the batch fermentation method in California biodiesel plants, and does not require the separation of single batches of biodiesel and glycerin.

Greenline, a California-based technology firm, has successfully propagated this continuous flow technology to many of the biodiesel production facilities in California (i.e. American Bio-fuels). Their MK-series processing units remove all water content in the first stage of processing, which allows it to work without excessive water and energy consumption. It also allows a producer to avoid the financial burden of water-regenerating hardware (Bryan 2005).

Production Capacity

Although widely utilized in Western Europe, total biodiesel use in the United States amounts to about 250 million gallons (National Biodiesel Board 2007), as compared to the nationwide on-highway diesel

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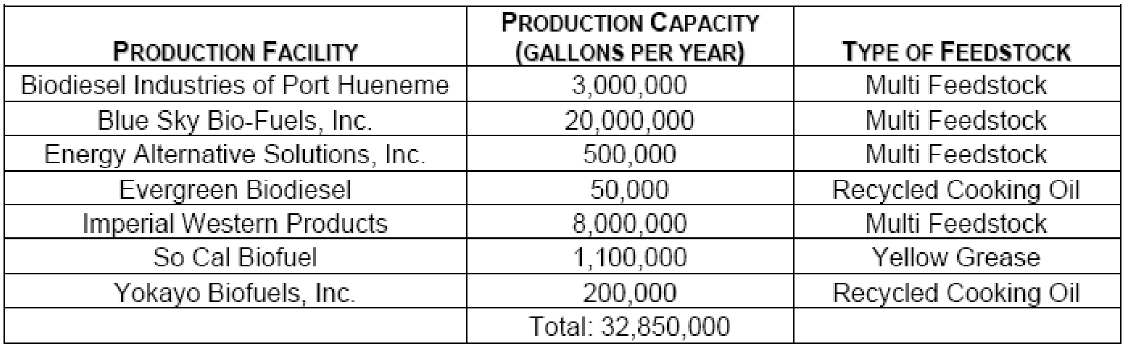
[52] Operating costs include the price of energy, natural gas, labor, alcohol, catalyst, and storage facilities.

consumption of 39 billion gallons (Energy Information Administration 2007). However, given the fact that biodiesel can be utilized in any diesel-engine, the transition from diesel to biodiesel requires little change in infrastructure. Therefore, it follows that the potential for growth in the biodiesel industry depends on the level of diesel consumption in a particular region. California is the second-largest consumer (after Texas) of petroleum diesel (Rougle 2005), and could expand into more diesel-engine using sectors (i.e. ships, fleets) if it could expand its production capacity. Before the February 2007 addition of the Blue Sky Bio-Fuels facility, the state's 2005 biodiesel production capacity was only 16 million gallons/year, representing 1/2 percent of CA diesel production (Cal EPA 2005, 15)

Following construction of the Oakland production facility, California is now capable of producing over 32 MMgy, but this number still dwarfs the CA diesel demands[53]

Table 1.28.4: California Production Capacity



PRODUCTION FACILITY	PRODUCTION CAPACITY (GALLONS PER YEAR)	TYPE OF FEEDSTOCK
Biodiesel Industries of Port Hueneme	3,000,000	Multi Feedstock
Blue Sky Bio-Fuels, Inc.	20,000,000	Multi Feedstock
Energy Alternative Solutions, Inc.	500,000	Multi Feedstock
Evergreen Biodiesel	50,000	Recycled Cooking Oil
Imperial Western Products	8,000,000	Multi Feedstock
So Cal Biofuel	1,100,000	Yellow Grease
Yokayo Biofuels, Inc.	200,000	Recycled Cooking Oil
	Total: 32,850,000	

Source: National Biodiesel Board (2007)

One optimistic note is that the availability of feedstock in the United States is not a limiting factor on the growth of the biodiesel industry. With a one-to-one input-output ratio (one gallon soybean oil → one gallon biodiesel), the 18.340 billion pounds of annual soybean oil has the potential to produce 2.413 billion gallons of biodiesel.[54] Moreover, recycled cooking oils, animal fats, and other types of vegetable oils can be used to produce biodiesel, and a table of the annual production of other US

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[53] 2004 diesel consumption in CA was $2.9 billion, or approximately 1,036 million gallons, meaning that even if each production facility were to produce to its maximum capacity, the amount would only cover about 3% of biodiesel needs.

[54] One gallon of soybean oil weighs 7.6 pounds; (1 gallon/7.6 pounds) * (18.340 pounds) = 2.413 billion potential gallons of biodiesel

Expected Trends

vegetable oils is listed below. Of course, the biodiesel industry could not approach this potential of 2.413 billion until the aggregate capacity of the production facilities nears this number (currently around 750 MMgy).

Table 1.28.5: Total Annual Production of US Oils

Vegetable Oil Production (Billion pounds/yr)	
Sunflower	**1.000**
Cottonseed	**1.010**
Corn	**2.420**
Others	**0.669**

Source: Pearl (2002)

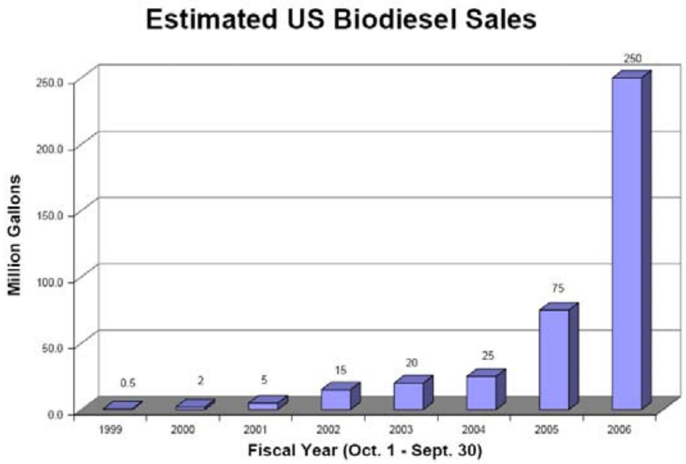
In short, a maximum production capacity of 32 MMgy only meets about 3% of California's diesel needs, and the actual biodiesel/diesel consumption ratio in California is even less.

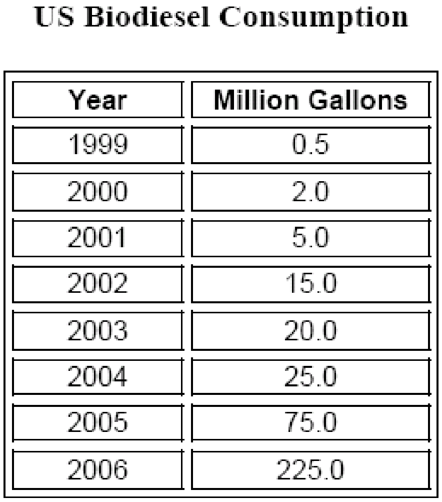
The previous section exposed the minimal presence of biodiesel in the California diesel-provider sector, but does this imply extensive room for growth, or an early death of an infant industry? Part of the outcome will depend on the success of the pioneer biodiesel firms in California. American Bio-fuels, one of the earlier production plants, suffered from a fire and has decided to not rebuild another plant (a *de facto* exit from the industry). Also, the new trend in the California industry appears to be building smaller production facilities. The technology section introduced Greenline's MK-series units, and the company says that with this technology, a 1 MMgy processing unit can be had for as little as $150,000 (Bryan 2005). In fact, Greenline, at this moment, is under contract to build small-scale "containerized" plants for an undisclosed client (Bryan 2005).

Despite these valiant efforts, it does not seem logical to take the small-scale approach when trying to meet the 1.4 billion diesel demand in California. The biodiesel industry will not flourish unless it can build large-scale, efficient plants that can bring the cost of biodiesel in line with petroleum-derived diesel. This is an interesting form of competition, because the most commonly used form of biodiesel is B20, with 80% diesel.

The issues of supply and demand for biodiesel will be addressed in the last section, but we can see in the following graph that biodiesel demand has risen sharply in the last two years, mostly due its increased availability.

Figure 1.28.4: Biodiesel Market Size



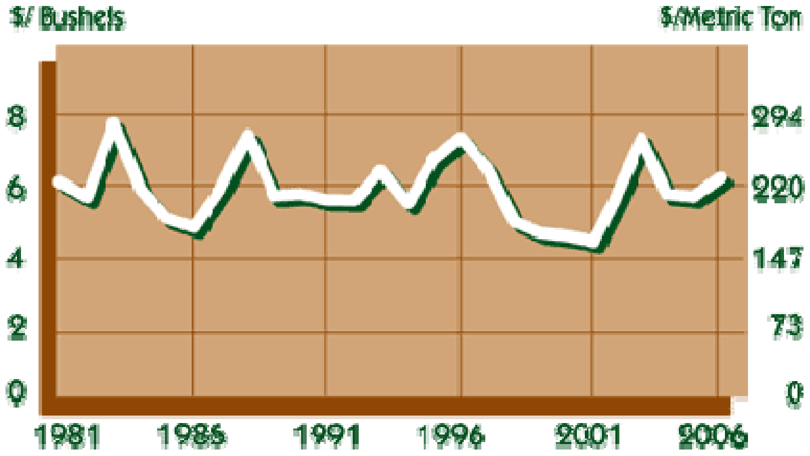

US Biodiesel Consumption

Year	Million Gallons
1999	0.5
2000	2.0
2001	5.0
2002	15.0
2003	20.0
2004	25.0
2005	75.0
2006	225.0

Source: National Biodiesel Board (2007)

Meanwhile, the price of the principal input of biodiesel, soybeans, has been relatively stable in the last few decades. If the price stability were to hold true, then we can return to the technological innovations argument that with stable soybean oil prices, decreases in overhead/processing costs from improved technology can reduce the overall price of biodiesel. The last two years have shown price decreases (see next section) in B99-100 and B20, but the price of B20 were only lower than petroleum-derived diesel twice in the five reports.

Figure 1.28.5: U.S. Soybean Prices Paid to Farmers 1981-2006



Source: USDA

Relationship with the Diesel Industry

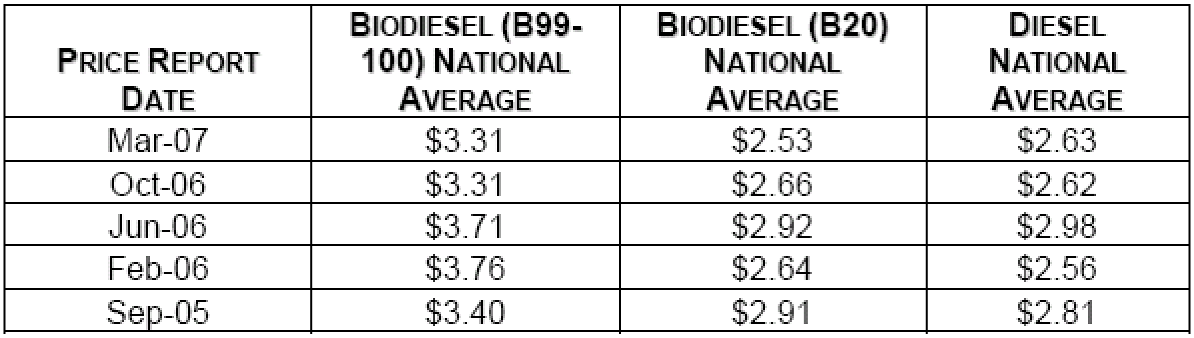
Based on the commentary by various diesel-related firms in response to the ARB biodiesel policy, one can construe that the diesel producers do not see the biodiesel industry as legitimate threat, and some diesel-engine makers see the opportunity to work in conjunction with biodiesel producers (i.e. making B100l-compatible engines). Biodiesel in its infant stage represents a minimal fraction of diesel consumption (estimated at 0.5% in 2005 and at most 3% for 2007). Furthermore, the nature of the blended products points to collaboration rather than competition.

In order to determine if biodiesel and diesel are complementary or substitute goods, we would have to assess the cross-price elasticity between the goods. Unfortunately, an appropriate statistic is not readily available, but one should consider the following:

1) Since B100 is not priced competitively with diesel, is not viewed as compatible with all diesel engines, and does not reduce GHG emissions as sharply as lower blends, then overall, B100 should not have a strong relationship with a diesel (i.e. changes in diesel price do not drastically change the quantity demanded of biodiesel).

2) The increase in the price of diesel often results in an increase in the quantity demanded of biodiesel, because diesel producers often sell low biodiesel blends (<B5) rather than pure diesel.[55] Moreover, Imperial Western Products, Inc. has noted rises in sales after price increases in diesel. This would imply that the products are substitutes, but in an unorthodox way (partial substitution of less than 5% rather than full substitution)
3) The case for complementary goods stems from the fact that the biodiesel blends (i.e. B20) and diesel would be complementary, since a decrease in the price of diesel would mean a decrease in the price of the inputs of B20 (80% is diesel), thereby increasing quantity demanded. Despite this, diesel and B20 are usually seen as competitors, and for most petroleum distributors, the retail price of B20 and diesel is what determines the product that they choose.

Table 1.28.6: Biodiesel and Diesel Prices



PRICE REPORT DATE	BIODIESEL (B99-100) NATIONAL AVERAGE	BIODIESEL (B20) NATIONAL AVERAGE	DIESEL NATIONAL AVERAGE
Mar-07	$3.31	$2.53	$2.63
Oct-06	$3.31	$2.66	$2.62
Jun-06	$3.71	$2.92	$2.98
Feb-06	$3.76	$2.64	$2.56
Sep-05	$3.40	$2.91	$2.81

Source: US Department of Energy: Energy Efficiency and Renewable Energy

It can be assumed that since B100 and other biodiesel blends are not consumed in large quantities, diesel producers do not view the industry as a competitor, and therefore, do not have an incentive to stagnate the growth of the biodiesel industry in California.

Summary of Relevant AB32/ARB Policies

The California Air and Resource Board first presented their "Suggested ARB Biodiesel Policy" in May 2006, and clarified some ambiguously defined terms in their second copy, released in November 2006. The following is a summary of the standards established in the first edition:

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[55] Biodiesel blends less than B5 are considered to be diesel, and the diesel producers simply label biodiesel as a lubricant additive.

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- Blends B20 and below must comply with California diesel standards.
- The policy would not address potential No$_x$ increase
- The policy would not address higher blends of biodiesel
- Blended biodiesel used in on/off road diesel vehicles must meet the American Society of Testing and Materials (ASTM) 6751 requirements [15ppm maximum of sulfur], AND be under 20% biodiesel by volume
- Only vehicles using CARB verified retrofit devices can use blends > B20

In Executive Order S-06-06, Governor Schwarzenegger established the target to produce a minimum of 20 percent of the state's biofuels (ethanol and biodiesel) within California by 2010, 40 percent by 2020, and 75 percent by 2050.

Since September 1, 2006, California has redefined ultra-low sulfur diesel (ULSD) to mean less than 15 ppm, an allowance much lower than the previous standard of 500 part per million.[56]

Biodiesel Tax Credit

Terms and Conditions

The volumetric biodiesel tax credit was passed as part of the JOBS Act of 2004, and became effective on January 1, 2005. The excise tax credit may be claimed by either the producer, importer (distributor), or blender. The majority of operating California biodiesel facilities function as both producers and blenders, and these firms must make this apparent in the IRS Form 637 (National Biodiesel Board 2007). Furthermore, since the process to declare oneself as an importer is both lengthy and meticulous, most California distributors require that the price of the biodiesel already reflect the excise tax credit (Wright 2007). This tax incentive equates to one penny per percent of biodiesel in a fuel blend made from agricultural products like vegetable oils (i.e. soybean oil0, and one-half penny per percent for recycled oils.

An important caveat to the tax credit legislation is that unblended B100 does not qualify for the excise tax credit. However, the definition of a "biodiesel mixture" is a mixture of biodiesel and diesel fuel containing at least 0.1% of diesel fuel. Therefore, producers of B100 will often sell a mixture of 999 gallons of biodiesel and 1 gallon of diesel fuel to make a B99.9 blend. In this case, B99.9 from soybean

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[56] The EPA also proposed this standard in October 15, 2006,

oil would receive $1/gallon tax credit whereas B99.9 from recycled cooking oil would receive $0.50/gallon.

Implications

Although the tax credit means heavier use of soybean oil (91.5% of biodiesel) under the status quo conditions, the tax credit will expire at the end of 2008. Assuming that the prices of inputs stay constant and that no act of legislation replaces the tax incentive, then the marginal cost of producing biodiesel from soybean oil should exceed the MC from using recycled cooking oil. Thus, we may see a shift in inputs away from soybean oil, particularly in facilities using multi feedstock.

Economic Implications of the Biodiesel Policies

Supply-side factors: competitiveness and barriers to entry

The California biodiesel industry is comprised of seven firms, ranging from very small (50,000 gallons) to large scale (20 MMpy). Although technology companies like Greenline have been working to allow for small-scale plants to enter the industry, the fixed costs, similar to most renewable energy/natural resources industries, are extremely high. For example, the cost of storage facilities for an average plant is already over one million dollars. Based on the steep input prices, the biodiesel industry is not particularly profitable. Consequently, there is a fear among biodiesel executives that it will be difficult to maintain financial stability without the tax excise credit, which is due to expire in a half year.

At this early stage of the industry, the firms are not competitive amongst each other, but rather jointly working together to propagate the industry as a whole. In example, the individual biodiesel companies focus on research and development that support the safe usage of biodiesel.

Demand-side Factors: Consumer Analysis

Although petroleum distributors are the direct consumers of the biodiesel produced in California plants, the focus of the consumer analysis should be on the eventual users of biodiesel, namely the users of diesel-engines. Major diesel-engine users include those involved in on-road transportation, farming, rail transportation, marine shipping, off-road uses (mainly mining, construction, and logging), electric power generation, and military transportation.

In California, the main consumers of biodiesel can be separated into five categories: the federal government, utilities, municipalities, private companies, and individuals. For example, in 2002, Fetzer Vineyards began using biodiesel blends in all of its 15 field tractors to help lower greenhouse gas emissions. By 2003, they were using biodiesel in half of their 12 big rig trucks that haul wine and glass (Fetzer Vineyards 2005).

Table 1.28.7: Biodiesel Users in California

FEDERAL GOVERNMENT	UTILITIES	MUNICIPALITIES	PRIVATE COMPANIES	INDIVIDUALS
29 Palms	PG&E	City of Berkeley	Fetzer Winery	Fuel Cooperatives
Travis AFB	SoCal Edison	Alameda County	Thanksgiving Coffee	Card lock stations
Channel Islands Nat'l Park	SDG&E		JR Cardenas Construction	
Marine Corps Station				
Vandenberg AFB				
Port Hueneme Naval Base				

Short-run/Long-run predictions: pricing fluctuations

The ARB Biodiesel policy does not play favorably into the hands of most biodiesel firms, since it requires that all blends B20 and below meet California diesel fuel standards. The standards for diesel have become stricter in previous years, specifically the stipulation that diesel have less than 15ppm sulfur. Therefore, biodiesel producers could attempt to produce B20.1 (201 gallons of biodiesel, 799 gallons of diesel), but the primary issue is that they need to work in conjunction with the diesel-engine manufacturers. Currently, the major manufacturers have released statements about their recommendations for biodiesel, including:

- EMA: up to B5
- Caterpillar: some engines approved for B100, others limited to B5
- Cummins: Engines approved for B5
- Detroit Diesel Corporation: Approve up to 20% biodiesel if produced from virgin soybeans
- John Deere: Engines approved for B5
- Bosch: Engines approved for B5 and meet ASTM D6751
- Delphi: Engines approved for B5 and meet ASTM D6751

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- Stanadyne: Engines approved for B5 and meet ASTM D6751

Source: NREL (2003)

Caterpillar is the only company that has approved the use of B100 in their engines, and Detroit Diesel Corporation allows up to B20. The rest of the engine manufacturers only approve blends of B5 or less, which can be viewed as a severe problem in promoting the use of biodiesel. Given the suggested ARB biodiesel policy, anything less than B20 will need to meet all diesel standards, meaning that the increasingly stringent diesel standards will hinder the production of biodiesel. Given these circumstances, it seems unlikely that biodiesel blenders, also without the tax credit, will be able to competitively price B20.

A possible option that biodiesel firms may pursue is to collaborate with diesel manufacturers to jointly create biodiesel-compatible engines for higher blends (>B20). The successful marketing of these engines will undoubtedly increase the demand for biodiesel. Another option of biodiesel firms is to lobby for the renewal of another tax credit program, either at the federal or state level.

1.29 California Solar Initiative

1.29.1 Sector Analysis

With only about 10% of California's energy being renewable, there is high growth potential for the solar-cell production and photovoltaics installation industries. The solar technology industry is mainly located in the Silicon Valley, where high-tech companies are scrambling to create more efficient, low cost solar-cells from silicon. Major PV system installers are located throughout California. To further promote the consumption of solar energy, the California Energy Commission and the California public Utilities Commission are giving incentives for Californians to install solar electricity systems in existing and new residential and commercial buildings through the California Solar Initiative,. With increasing consumer interest in solar energy, new technologies, and incentives, capital and installation costs will continue to decrease, which will allow more people to adopt this type of energy and reduce carbon dioxide emissions.

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Production Statistics

A photovoltaic system consists of photovoltaic module, which is an assembly of solar cells on a panel that is used to absorb sunlight and then converted into electricity. A group of these PV modules is called an array.

The ability for solar energy to expand, the price of solar energy must be reduced. This has increased the research and development in "thin film" solar cells, which use little or no silicon and may significantly reduce costs. Because thin-film cells are very efficient at absorbing light, they require less than 1% of the semiconductor material needed by the common solar-cell. Currently, about 40% of the cost of a conventional module goes on silicon. Making a thin-film module will reduce most of the costs. America's National Renewable Energy Laboratory. Thin-film technology also offers the potential for faster manufacturing processes and higher levels of automation, which cut costs (the Economist 2007).

Technology

There are two types of solar cells that are manufactured to absorb sunlight. Crystalline Silicon Solar Cells, which make up 93% of the market share and Thin Film Solar Cells, which make up the remaining 7%. Crystalline Silicon Solar Cells are made of two types of crystalline silicon (monocrystalline and multicrystalline silicon wafers). Thin Film Solar Cells are made of amorphous silicon, which is much more malleable, but efficiencies deteriorate once it is worn out. The technology that is most successful in achieving low manufacturing costs in the long run is likely to be the one that can deliver the highest stable efficiencies (probably at least 10%) with the highest process yields.

Average residential rooftop PV power system installed in Sacramento, CA will produce 2,890 kWh of electricity per year, and eliminate 3,583 pounds of carbon dioxide and one pound of nitrous oxide emissions in the first year (Fourer 2001). Although the costs of producing solar cells is very expensive, decades of research have improved the efficiency of silicon-based solar cells from 6% to an average of 15% today. Improvements in manufacturing have reduced the price of modules from about $200 per watt in the 1950s to $2.70 in 2004. Most speculate that the expected price of solar energy will be cost-competitive with grid electricity.

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Industrial Applications

Solar Energy has been the power supply of choice for Industrial applications, where power is required at remote locations. At remote locations, these applications of solar power are economic, even without subsidies or incentives (solarbuzz.com).

Central Power Stations

Central Power applications use solar energy in the same configuration that a Utility would utilize a major power station. This is distinctly different from the other applications on this page, which are known as “distributed power” or power distributed in small aggregate amounts of power, usually close to the point of use of the electricity. This is less efficient than individual generations of solar, where extra generated solar electricity is credited by either PG&E, SDG&E, or SCE.

Central solar power generation plants have been installed in Italy, US and Spain, for example. However, all these plants are “pilot” in nature. Central solar plants may be attractive under certain conditions, but they do not capitalize on the competitive strengths of solar PV in terms of its flexibility of location (i.e. being located close to the customer) and its ability to be installed incrementally (solarbuzz.com).

Commercial Buildings

There are many feasible ways to include solar energy in commercial buildings. For example, on an office building, atria can be covered with glass/glass PV modules, which can be semi-transparent to provide shaded light and to absorb sunlight. On a factory, large roof areas have been the best location for solar modules. If they are flat, then arrays can be mounted using techniques that do not breach the weatherproof roof membrane. Also, skylights can be covered partially with PV modules.

The vertical walls of office buildings provide several opportunities for PV incorporation. The first is as a “curtain wall system” that constitutes the weather barrier of the building. The second, as a “rainscreen overcladding system” where there is an underlying weather barrier that provides the insulation and sealing of the building.

The third option is to create sunshades or balconies incorporating a PV System. Sunshades may have the PV System mounted externally to the building or have PV cells specially mounted between glass sheets comprising the window (Solarbuzz.com).

A study was done by the energy Technical Support Unit (ETSU) in the United Kingdom on low-energy office buildings. Results show that the average reduction in energy consumption between the low-energy design and the reference solar office building was 52%, giving energy cost reduction of 49%. The capital costs for construction were similar to the conventional building, and the carbon dioxide emissions were reduced by 15% (Prasad & Snow, 2005).

Cost & Industry

The San Jose solar-cell manufacturer, SunPower Corp. more than tripled its sales to $236.5 million for 2006 from $78.6 million in 2005. Like most solar-cell manufacturers, SunPower Corp. is hoping to reduce costs by 50 percent in 2012. SunPower's quarterly research-and-development spending rose 29 percent during 2006, and much of the $2.6 million the company spent on R&D during the final quarter of 2006 is focused on reducing production costs and improving efficiency (Tribble, 2007). However, despite early breakthroughs in solar-cell production, solar energy costs are still two to three times higher than the electricity grid at about 20 to 40 cents/kilowatt-hour (LaPedus, 2007). However, the exact cost of solar electricity depends on the location and the cost of finance available to the installer of the system. Estimates portray that in order for “the solar industry to make a systematic penetration in to the electricity segment, installed solar system costs will need to drop from around $8-10/Wp to $3/Wp. This would continue the trend shown above of falling solar electricity costs over the last twenty-five years. A push to $3/Wp would bring solar energy costs from the present 30 cents per kilowatt-hour to around 10 cents per kilowatt-hour, which would allow it to compete more strongly with other renewables and capture a significant share of the electricity market” (solarbuzz.com). See Figure 1.29.1.

For typical home, a 3-kW grid-tied solar system costs about $17,500 to install after California’s rebate before tax breaks are deducted, which will take an average home three to seven years to breakeven with the installation cost (LaPedus 2007). Industry officials expect *California's* solar program to influence the PV market globally, "I believe *California* will become an aggressive solar market much like Germany and Japan, two countries widely known as solar energy users," says George Douglas of the National Renewable Energy Laboratory in Colorado. Material and installation can cost $9 to $10 per kilowatt. PowerLight Corp., Berkeley, Calif., reports that the payback period for a 140-kW system it installed for a Napa, Calif., vineyard was four years (ENR).

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Homes not located on the grid system, should install solar electricity systems. According to SolarBuzz.com. if a house is further than 1km from the nearest grid line then it is likely to be cheaper to install a PV system.

For commercial projects, developer and mechanical engineer jointly involved in making energy source decisions.

About 59% of the world solar product sales installed within the last 7 years were used in applications that were connected to the electricity grid. Photo-voltaic systems can be very cost competitive in off-grid industrial locations. See Figure 1.29.1. (SolarBuzz.com).

Perspectives & Conclusion

The solar energy and solar-cell industry in California is very welcoming of the California Solar Initiative, because it makes the high cost of installing a PV system for consumers and businesses less expensive through incentives. With higher demand and adoption of solar energy, firms can generate more profits and receive investments to fund further research to reduce costs, making it more widely available and affordable for households and businesses. In Figure 1.29.6, the improvements in the thin-cell solar cell will cause solar energy to grow exponentially.

Anyone is eligible for solar rebates given by the CPU or CEC, but low income families will be given extra incentives. The New Solar Homes Partnership will be directed with the CEC to work with builders and developers to incorporate high levels of energy efficiency and high-performing solar systems to create a self-sustaining solar market. This program is specifically targeted towards single family, low-income, and multi-family housing markets. In order to qualify for the rebates, homes must also be energy efficient. Currently, low-income families get 25% more rebates to install solar energy systems in their new homes. Some low-income families may be unable to qualify for loans to finance their solar energy systems or afford to spend an initial high cost before the system pays for itself. Apart from these deterrents, buyers may need to increase performance by installing other housing fixtures such as new windows, shades, and shutters.

If firms continue to find breakthroughs in cutting down solar-cell production costs, and consumers become more aware of the benefits of solar energy systems, the prices will go down and more people will adopt the technologies. This will bring California into the forefront, if it isn’t already of solar technology in the United States and in the world.

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Figure 1.29.1. Solar Energy: Competitive Positioning by each Market Segment of world solar product

	Solar markets (av of large 5 years)	Solar Price/Competing Energy source
Remote Industrial	17%	0.1-0.5 times
Remote Habitational	22%	0.2-0.8 times
Grid Connected	59%	2-5 times
Consumer Indoor	2%	n/a

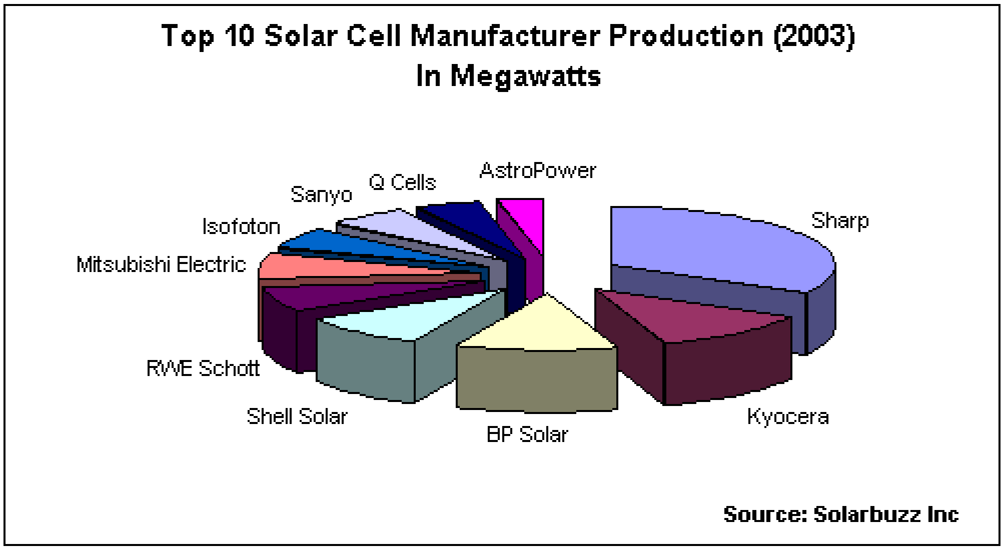
Source: PV Technology Roadmap Workshop 1999, modified by Solarbuzz

Figure 1.29.2. Guideline Electricity Generation Costs Today (cents/kWh)

Combined cycle gas turbine	3-5
Wind	4-7
Biomass gasification	7-9
Remote diesel generation	20-40
Solar PV central station	20-30
Solar PV distributed	20-50

Source: PV Technology Roadmap Workshop 1999, modified by Solarbuzz

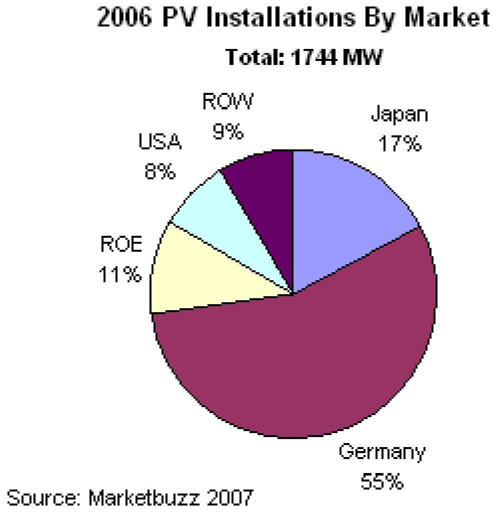
Figure 1.29.3:



Top 10 Solar Cell Manufacturer Production (2003)
In Megawatts

Source: Solarbuzz Inc

Figure 1.29.4:



2006 PV Installations By Market
Total: 1744 MW

Source: Marketbuzz 2007

Figure 1.29.5: Photovoltaic Supply Chain

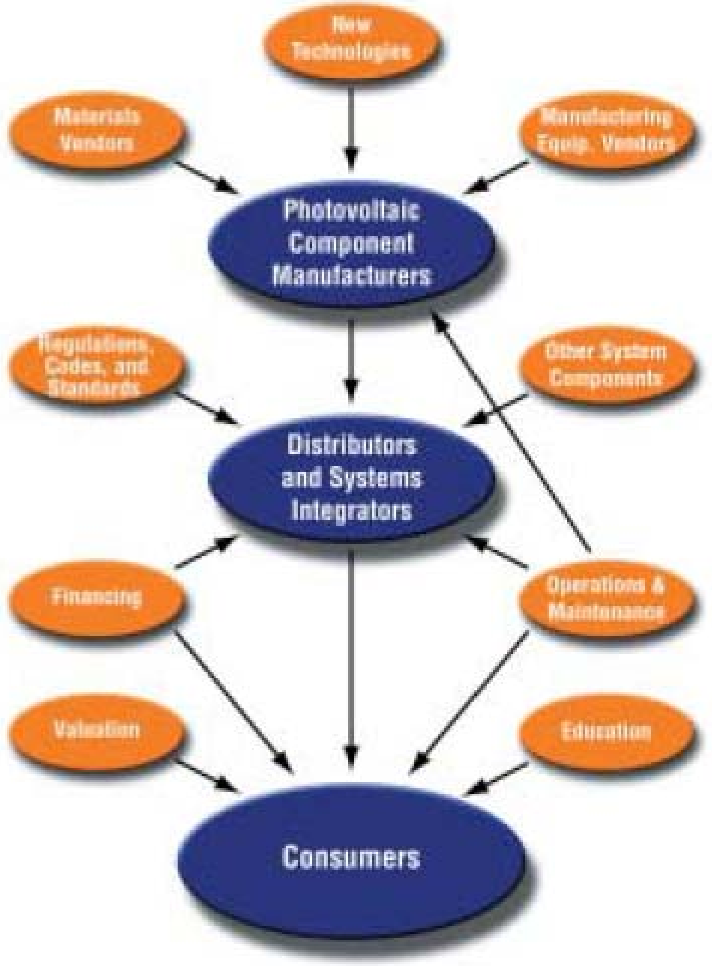


Figure 4 - A wide variety of manufacturers, businesses, regulatory boards, and educational organizations help bring high-quality solar-electric power to consumers.

Source: Sandia. http://www.sandia.gov/pv/docs/PDF/PV_Road_Map.pdf

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Figure 1.29.6: PV Industry Output Projections

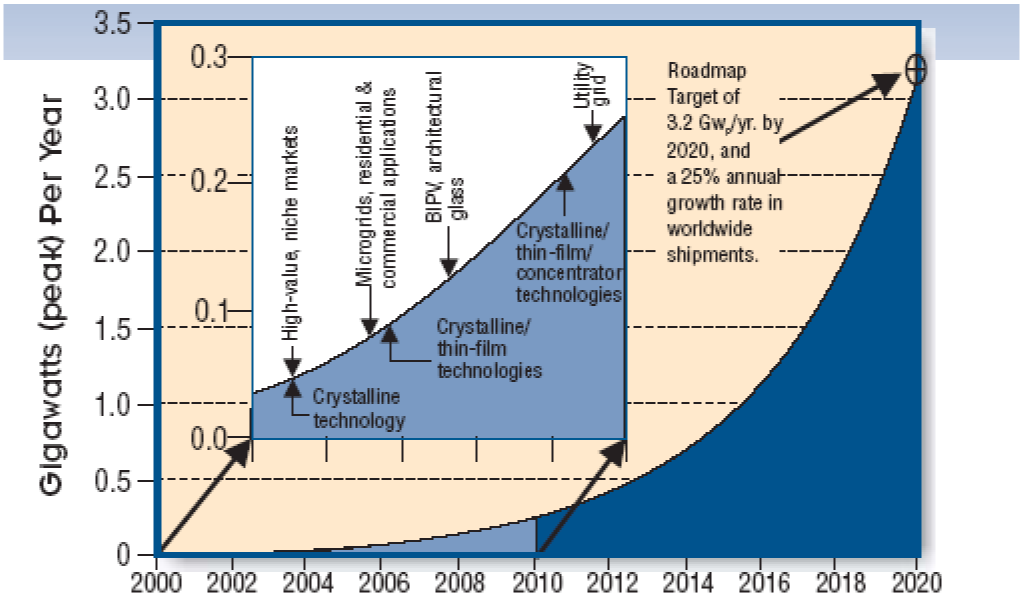

Figure 8 - Goal for U.S. manufactured PV modules installed in U.S. domestic applications, for a U.S. market share that increases linearly from 30% to 50% from 2000 to 2020. Inset shows the evolution of the impact of various markets and technologies.

Figure 1.29.7. Source: California Energy Commission

Cost of Electricity Generation 1994 Compared to 2003		
Technology [1]	1994 Cost of Electricity (cents/kWh)	Current Cost of Electricity (2003 data, cents/kWh)
Hydroelectric [2]	0.31 to 4.4	0.25 to 2.7
Nuclear [3]	2.5	1.4 to 1.9
Coal [4]	1.9 to 2.3	1.8 to 2.0
Natural Gas [5]	2.5 to 11.7	5.2 to 15.9
Solar [6]	16.4 to 30.5	13.5 to 42.7
Wind [7]	7.6	4.6

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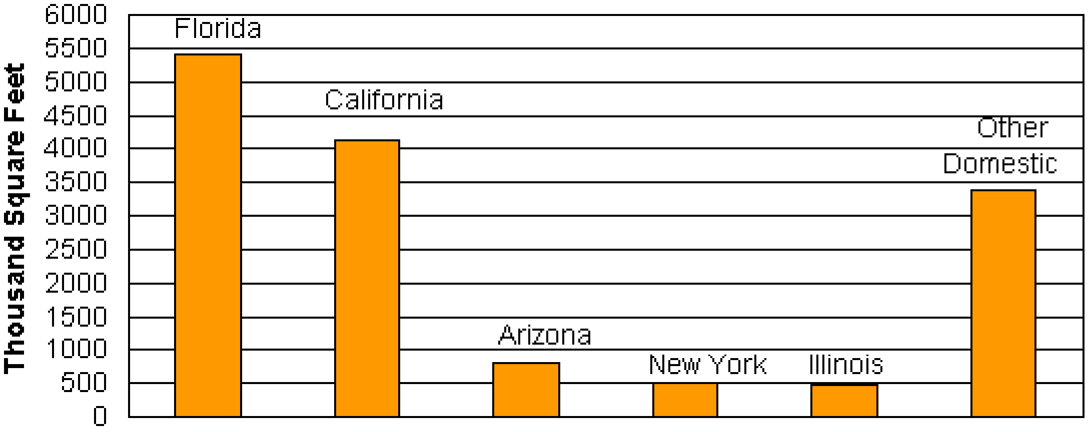
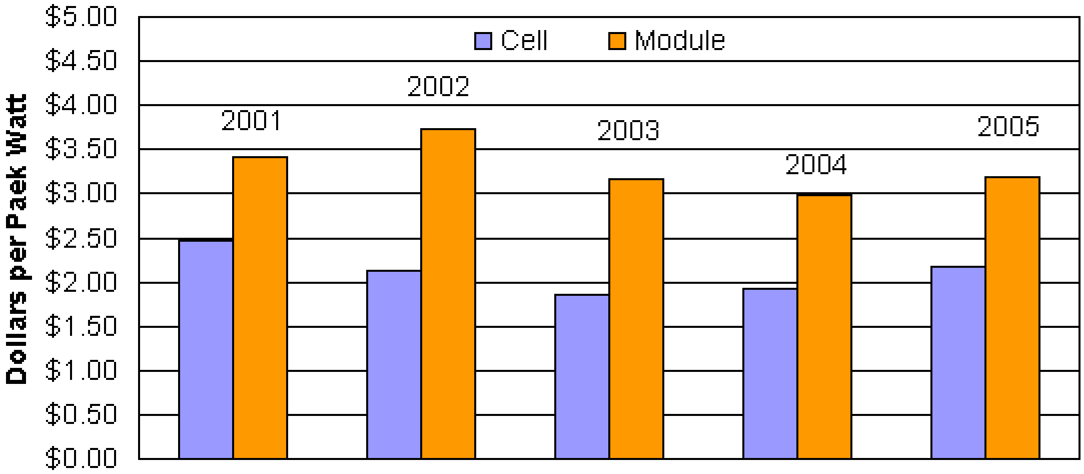
Figure 1.29.8: Solar Thermal Collector Shipments Top Domestic Destinations, 2005



Source: Energy Information Administration, Form EIA-63A, "Annual Solar Thermal Collector Manufacturers Survey."

Figure 1.29.9: Photovoltaic Cell and Module Average Prices, 2001-2005



Source: Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."
http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/highlights10.html

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Contacts List - Solar Thermal Collector Manufacturers	Address
Fafco Inc	435 Otterson Dr, Chico, CA 95928
Heliodyne Inc	4910 Seaport Avenue, Richmond, CA 94804
Industrial Solar Technology	4420 Mcintyre Street, Golden, CO 80403
Radco Products, Inc.	2877 Industrial Parkway, Santa Maria, CA 93455
Sealed Air Corporation	3433 Arden Road, Hayward, CA 94545
SolarRoofs.com	5480 Gibbons Drive, Suite G, Carmichael, CA 95608
Sun Quest	1555 Rankin Avenue, Newton, NC 28658
SunEarth Inc	8425 Almera Avenue, Fontana, CA 92335

Contacts List - Photovoltaic Collector Manufacturers	Address
Amonix Inc	3425 Fujita Street, Torrance, CA 90505
Innergy Power Corporation	9375 Customhouse Plaza, Building 1, Suite J, San Diego, CA 92154
Mitsubishi Electric & Electronics USA, Inc.	5655 Plaza Drive, Cypress, CA 90630
Mitsui Comtek Corp.	20300 Stevens Creek Blvd, Cupertino, CA 95014
Pacific SolarTech	44843 Fremont Blvd, Fremont, CA 94539
SANYO Energy (USA) Corporation	2055 Sanyo Avenue, San Diego, CA 92154
Shell Solar Industries LP	4650 Adohr Lane, Camarillo, CA 93012
SunPower Corporation	3939 North First Street, San Jose, CA 95314

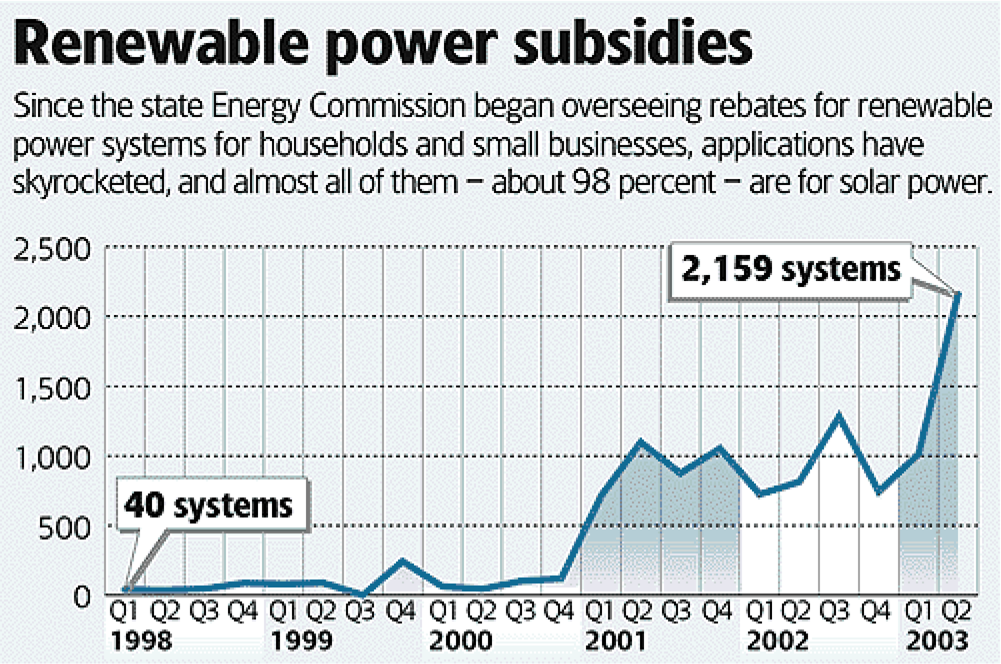
Please note that the Energy Commission staff gathered this information from both Commission staff reports and secondary sources. While this is a best effort, it should not be considered definitive. Figures for “Current Cost” is from 2003, the latest that such costs have been estimated.

**Cost of Electricity Generation
1994 Compared to 2003**

Technology [1]	1994 Cost of Electricity (cents/kWh)	Current Cost of Electricity (2003 data, cents/kWh)
Hydroelectric [2]	0.31 to 4.4	0.25 to 2.7
Nuclear [3]	2.5	1.4 to 1.9
Coal [4]	1.9 to 2.3	1.8 to 2.0
Natural Gas [5]	2.5 to 11.7	5.2 to 15.9
Solar [6]	16.4 to 30.5	13.5 to 42.7
Wind [7]	7.6	4.6

Current actual cost of generation data for solar is not available because virtually all solar plants are owned by merchant generators, who are not required to report their costs to FERC or any government energy agency. The 2003 costs in this table are based on the California Energy Commission’s Comparative Costs of California Central Station Electricity Generation Technologies Report, which estimated the cost of utility-sized solar photovoltaic (50 MW), solar thermal-stirling dish (31.5 MW), and solar parabolic with thermally enhanced storage (110 MW). The 1994 solar costs are estimates for building a new system (including amortized capital costs over useful life of facility) from the *1996 Energy Technology Status Report Summary* (Commission publication # P500-96-006, December 1996, www.energy.ca.gov/etsr/) for a utility-sized (80 and 200 MW) parabolic trough solar hybrid system. The current solar costs are not directly comparable to the 1994 costs, since the Energy Commission does not have data that compare the same solar technologies, and the available data is from different sources.

Figure 1.29.10:

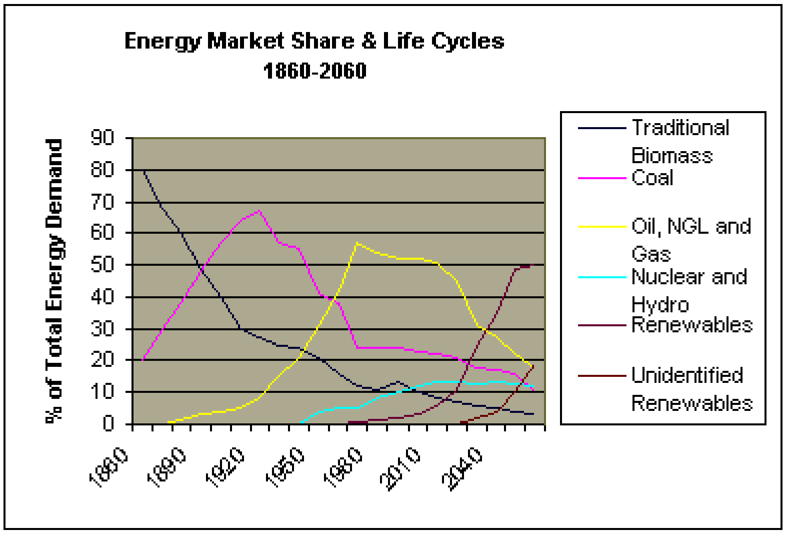


Renewable power subsidies

Since the state Energy Commission began overseeing rebates for renewable power systems for households and small businesses, applications have skyrocketed, and almost all of them – about 98 percent – are for solar power.

Source: http://www.californiasolarcenter.org/index.html

Figure 1.29.11:



Source: Deutsche Shell AG

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Largest Installed Solar Arrays in California

[redacted]

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[redacted]

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Table 1.29.1: Industry Statistics for Selected States, 2002

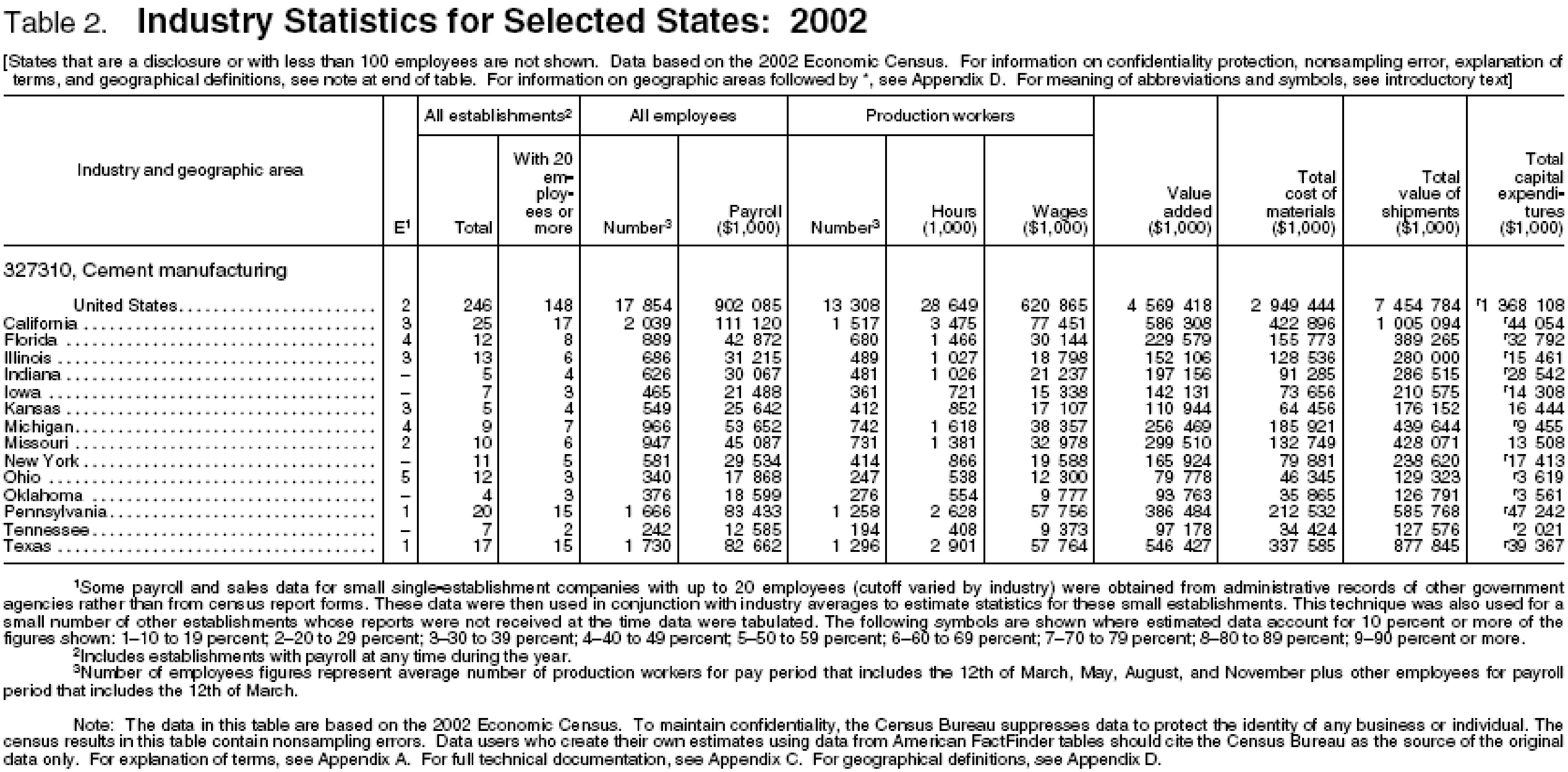

Table 2. Industry Statistics for Selected States: 2002

[States that are a disclosure or with less than 100 employees are not shown. Data based on the 2002 Economic Census. For information on confidentiality protection, nonsampling error, explanation of terms, and geographical definitions, see note at end of table. For information on geographic areas followed by *, see Appendix D. For meaning of abbreviations and symbols, see introductory text]

Industry and geographic area	E[1]	All establishments[2]		All employees		Production workers			Value added ($1,000)	Total cost of materials ($1,000)	Total value of shipments ($1,000)	Total capital expenditures ($1,000)
		Total	With 20 employees or more	Number[3]	Payroll ($1,000)	Number[3]	Hours (1,000)	Wages ($1,000)				
327310, Cement manufacturing												
United States	2	246	148	17 854	902 085	13 308	28 649	620 865	4 569 418	2 949 444	7 454 784	^{r}1 368 108
California	3	25	17	2 039	111 120	1 517	3 475	77 451	586 308	422 896	1 005 094	^{r}44 054
Florida	4	12	8	889	42 872	680	1 466	30 144	229 579	155 773	389 265	^{r}32 792
Illinois	3	13	6	686	31 215	489	1 027	18 798	152 106	128 536	280 000	^{r}15 461
Indiana	–	5	4	626	30 067	481	1 026	21 237	197 156	91 285	286 515	^{r}28 542
Iowa	–	7	3	465	21 488	361	721	15 338	142 131	73 656	210 575	^{r}14 308
Kansas	3	5	4	549	25 642	412	852	17 107	110 944	64 456	176 152	16 444
Michigan	4	9	7	966	53 652	742	1 618	38 357	256 469	185 921	439 644	^{r}9 455
Missouri	2	10	6	947	45 087	731	1 381	32 978	299 510	132 749	428 071	13 508
New York	–	11	5	581	29 534	414	866	19 588	165 924	79 881	238 620	^{r}17 413
Ohio	5	12	3	340	17 868	247	538	12 300	79 778	46 345	129 323	^{r}3 619
Oklahoma	–	4	3	376	18 599	276	554	9 777	93 763	35 865	126 791	^{r}3 561
Pennsylvania	1	20	15	1 666	83 433	1 258	2 628	57 756	386 484	212 532	585 768	^{r}47 242
Tennessee	–	7	2	242	12 585	194	408	9 373	97 178	34 424	127 576	^{r}2 021
Texas	1	17	15	1 730	82 662	1 296	2 901	57 764	546 427	337 585	877 845	^{r}39 367

[1] Some payroll and sales data for small single-establishment companies with up to 20 employees (cutoff varied by industry) were obtained from administrative records of other government agencies rather than from census report forms. These data were then used in conjunction with industry averages to estimate statistics for these small establishments. This technique was also used for a small number of other establishments whose reports were not received at the time data were tabulated. The following symbols are shown where estimated data account for 10 percent or more of the figures shown: 1–10 to 19 percent; 2–20 to 29 percent; 3–30 to 39 percent; 4–40 to 49 percent; 5–50 to 59 percent; 6–60 to 69 percent; 7–70 to 79 percent; 8–80 to 89 percent; 9–90 percent or more.

[2] Includes establishments with payroll at any time during the year.

[3] Number of employees figures represent average number of production workers for pay period that includes the 12th of March, May, August, and November plus other employees for payroll period that includes the 12th of March.

Note: The data in this table are based on the 2002 Economic Census. To maintain confidentiality, the Census Bureau suppresses data to protect the identity of any business or individual. The census results in this table contain nonsampling errors. Data users who create their own estimates using data from American FactFinder tables should cite the Census Bureau as the source of the original data only. For explanation of terms, see Appendix A. For full technical documentation, see Appendix C. For geographical definitions, see Appendix D.

(U.S….,Bureau 2002)

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Table 1.29.2 and Table 1.29.3: Kiln Data Summary By Process Type; Kiln Data Summary By Hazardous Waste Burning Status

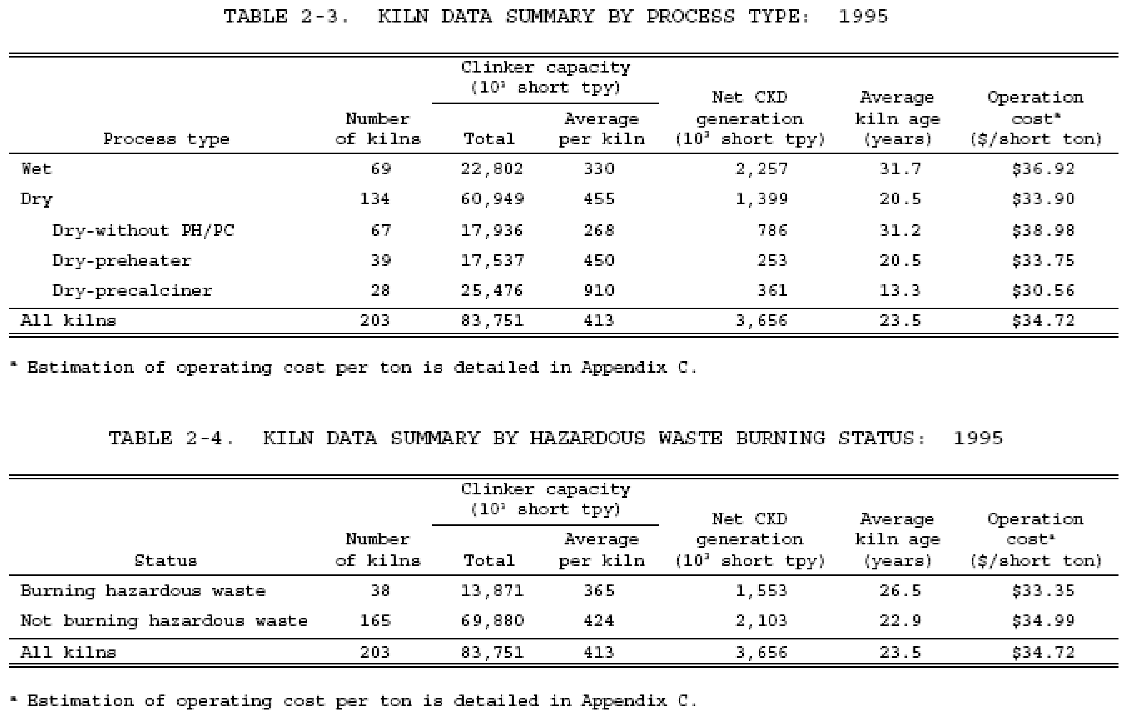

TABLE 2-3. KILN DATA SUMMARY BY PROCESS TYPE: 1995

Process type	Number of kilns	Clinker capacity (10^3 short tpy) Total	Clinker capacity (10^3 short tpy) Average per kiln	Net CKD generation (10^3 short tpy)	Average kiln age (years)	Operation cost[a] ($/short ton)
Wet	69	22,802	330	2,257	31.7	$36.92
Dry	134	60,949	455	1,399	20.5	$33.90
Dry-without PH/PC	67	17,936	268	786	31.2	$38.98
Dry-preheater	39	17,537	450	253	20.5	$33.75
Dry-precalciner	28	25,476	910	361	13.3	$30.56
All kilns	203	83,751	413	3,656	23.5	$34.72

[a] Estimation of operating cost per ton is detailed in Appendix C.

TABLE 2-4. KILN DATA SUMMARY BY HAZARDOUS WASTE BURNING STATUS: 1995

Status	Number of kilns	Clinker capacity (10^3 short tpy) Total	Clinker capacity (10^3 short tpy) Average per kiln	Net CKD generation (10^3 short tpy)	Average kiln age (years)	Operation cost[a] ($/short ton)
Burning hazardous waste	38	13,871	365	1,553	26.5	$33.35
Not burning hazardous waste	165	69,880	424	2,103	22.9	$34.99
All kilns	203	83,751	413	3,656	23.5	$34.72

[a] Estimation of operating cost per ton is detailed in Appendix C.

(Regulatory…Rulemaking, 1998)

Table 1.29.4: Portland Cement Shipped By Producers and Importers In the United States By District

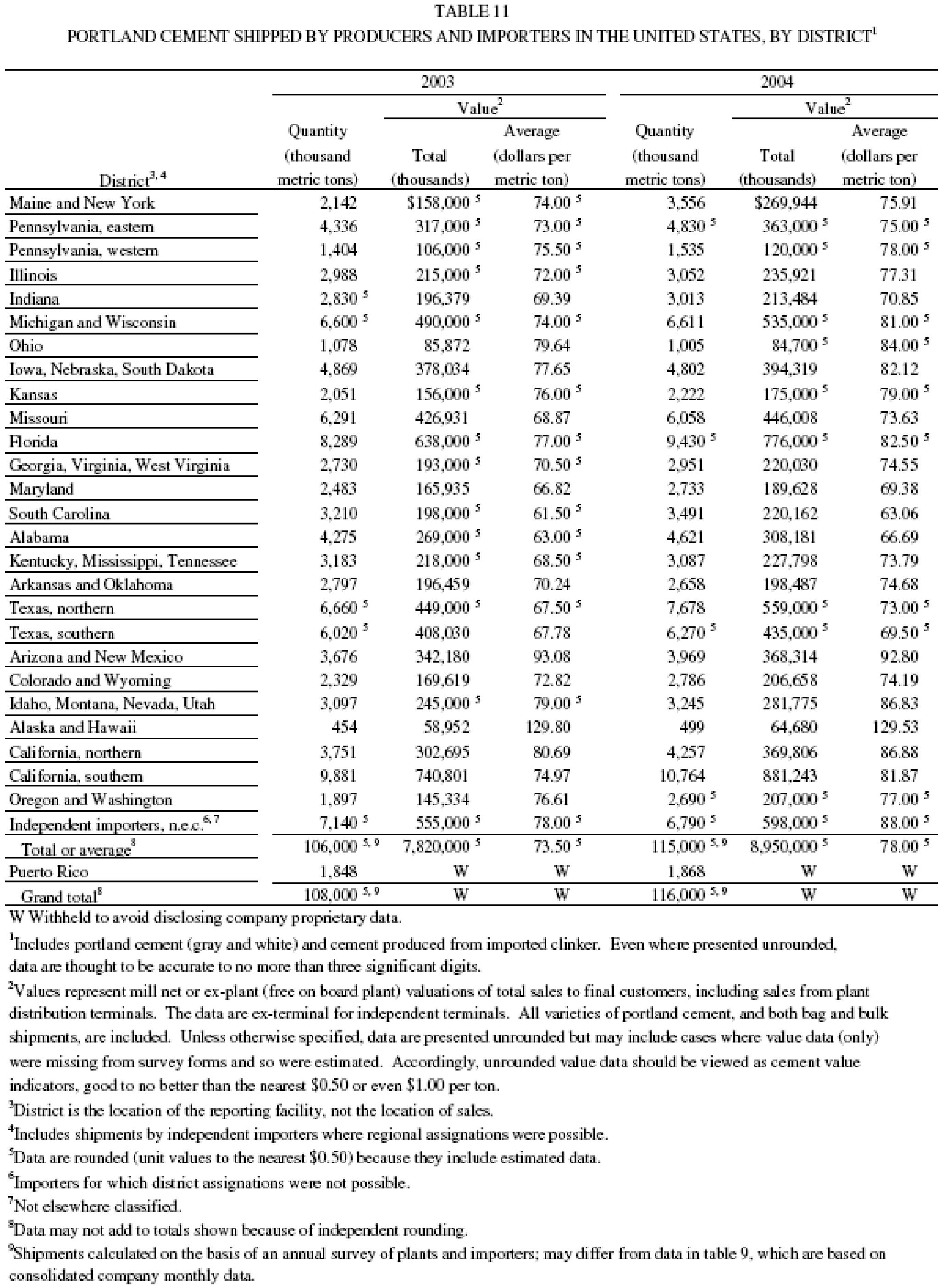

TABLE 11

PORTLAND CEMENT SHIPPED BY PRODUCERS AND IMPORTERS IN THE UNITED STATES, BY DISTRICT[1]

	2003			2004		
		Value[2]			Value[2]	
District[3, 4]	Quantity (thousand metric tons)	Total (thousands)	Average (dollars per metric ton)	Quantity (thousand metric tons)	Total (thousands)	Average (dollars per metric ton)
Maine and New York	2,142	$158,000 [5]	74.00 [5]	3,556	$269,944	75.91
Pennsylvania, eastern	4,336	317,000 [5]	73.00 [5]	4,830 [5]	363,000 [5]	75.00 [5]
Pennsylvania, western	1,404	106,000 [5]	75.50 [5]	1,535	120,000 [5]	78.00 [5]
Illinois	2,988	215,000 [5]	72.00 [5]	3,052	235,921	77.31
Indiana	2,830 [5]	196,379	69.39	3,013	213,484	70.85
Michigan and Wisconsin	6,600 [5]	490,000 [5]	74.00 [5]	6,611	535,000 [5]	81.00 [5]
Ohio	1,078	85,872	79.64	1,005	84,700 [5]	84.00 [5]
Iowa, Nebraska, South Dakota	4,869	378,034	77.65	4,802	394,319	82.12
Kansas	2,051	156,000 [5]	76.00 [5]	2,222	175,000 [5]	79.00 [5]
Missouri	6,291	426,931	68.87	6,058	446,008	73.63
Florida	8,289	638,000 [5]	77.00 [5]	9,430 [5]	776,000 [5]	82.50 [5]
Georgia, Virginia, West Virginia	2,730	193,000 [5]	70.50 [5]	2,951	220,030	74.55
Maryland	2,483	165,935	66.82	2,733	189,628	69.38
South Carolina	3,210	198,000 [5]	61.50 [5]	3,491	220,162	63.06
Alabama	4,275	269,000 [5]	63.00 [5]	4,621	308,181	66.69
Kentucky, Mississippi, Tennessee	3,183	218,000 [5]	68.50 [5]	3,087	227,798	73.79
Arkansas and Oklahoma	2,797	196,459	70.24	2,658	198,487	74.68
Texas, northern	6,660 [5]	449,000 [5]	67.50 [5]	7,678	559,000 [5]	73.00 [5]
Texas, southern	6,020 [5]	408,030	67.78	6,270 [5]	435,000 [5]	69.50 [5]
Arizona and New Mexico	3,676	342,180	93.08	3,969	368,314	92.80
Colorado and Wyoming	2,329	169,619	72.82	2,786	206,658	74.19
Idaho, Montana, Nevada, Utah	3,097	245,000 [5]	79.00 [5]	3,245	281,775	86.83
Alaska and Hawaii	454	58,952	129.80	499	64,680	129.53
California, northern	3,751	302,695	80.69	4,257	369,806	86.88
California, southern	9,881	740,801	74.97	10,764	881,243	81.87
Oregon and Washington	1,897	145,334	76.61	2,690 [5]	207,000 [5]	77.00 [5]
Independent importers, n.e.c.[6, 7]	7,140 [5]	555,000 [5]	78.00 [5]	6,790 [5]	598,000 [5]	88.00 [5]
Total or average[8]	106,000 [5, 9]	7,820,000 [5]	73.50 [5]	115,000 [5, 9]	8,950,000 [5]	78.00 [5]
Puerto Rico	1,848	W	W	1,868	W	W
Grand total[8]	108,000 [5, 9]	W	W	116,000 [5, 9]	W	W

W Withheld to avoid disclosing company proprietary data.

[1] Includes portland cement (gray and white) and cement produced from imported clinker. Even where presented unrounded, data are thought to be accurate to no more than three significant digits.

[2] Values represent mill net or ex-plant (free on board plant) valuations of total sales to final customers, including sales from plant distribution terminals. The data are ex-terminal for independent terminals. All varieties of portland cement, and both bag and bulk shipments, are included. Unless otherwise specified, data are presented unrounded but may include cases where value data (only) were missing from survey forms and so were estimated. Accordingly, unrounded value data should be viewed as cement value indicators, good to no better than the nearest $0.50 or even $1.00 per ton.

[3] District is the location of the reporting facility, not the location of sales.

[4] Includes shipments by independent importers where regional assignations were possible.

[5] Data are rounded (unit values to the nearest $0.50) because they include estimated data.

[6] Importers for which district assignations were not possible.

[7] Not elsewhere classified.

[8] Data may not add to totals shown because of independent rounding.

[9] Shipments calculated on the basis of an annual survey of plants and importers; may differ from data in table 9, which are based on consolidated company monthly data.

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Table 1.29.5: Portland Cement Shipments in 2004 By District and Type of Customer

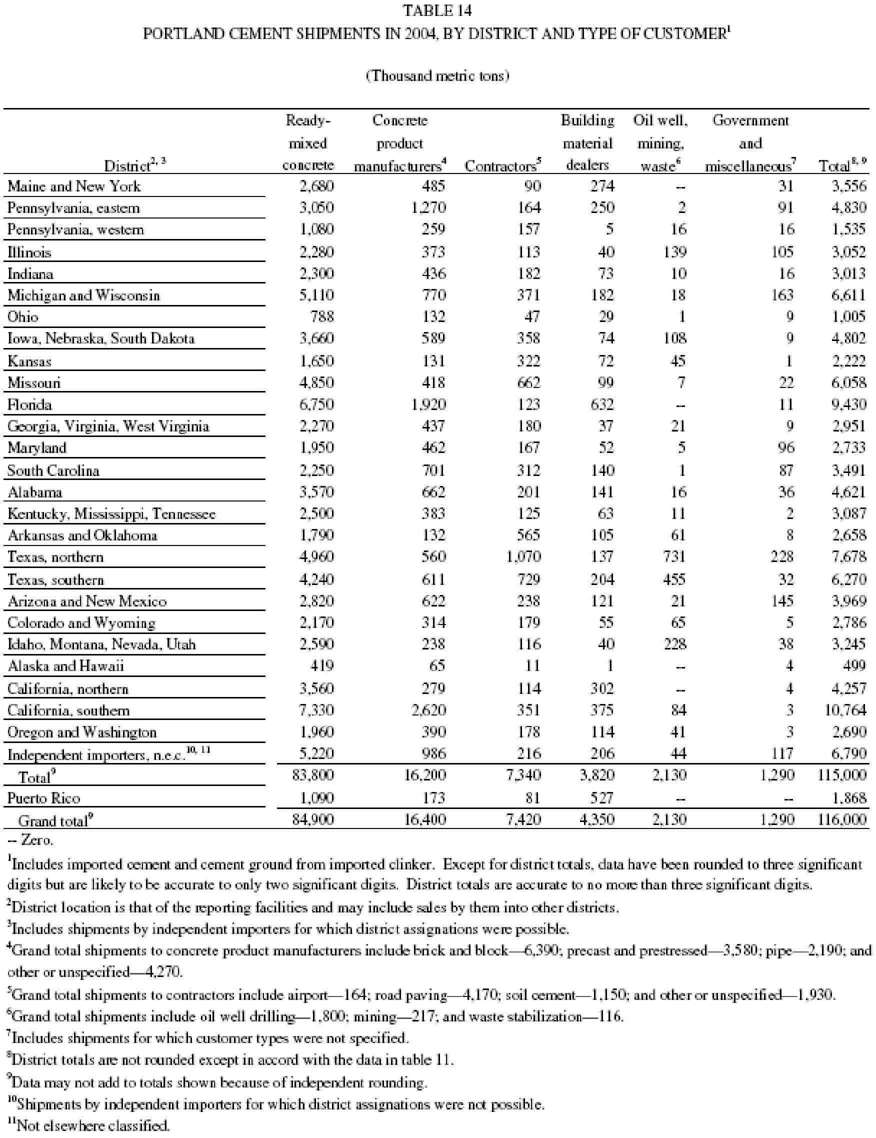

TABLE 14

PORTLAND CEMENT SHIPMENTS IN 2004, BY DISTRICT AND TYPE OF CUSTOMER[1]

(Thousand metric tons)

District[2, 3]	Ready-mixed concrete	Concrete product manufacturers[4]	Contractors[5]	Building material dealers	Oil well, mining, waste[6]	Government and miscellaneous[7]	Total[8, 9]
Maine and New York	2,680	485	90	274	--	31	3,556
Pennsylvania, eastern	3,050	1,270	164	250	2	91	4,830
Pennsylvania, western	1,080	259	157	5	16	16	1,535
Illinois	2,280	373	113	40	139	105	3,052
Indiana	2,300	436	182	73	10	16	3,013
Michigan and Wisconsin	5,110	770	371	182	18	163	6,611
Ohio	788	132	47	29	1	9	1,005
Iowa, Nebraska, South Dakota	3,660	589	358	74	108	9	4,802
Kansas	1,650	131	322	72	45	1	2,222
Missouri	4,850	418	662	99	7	22	6,058
Florida	6,750	1,920	123	632	--	11	9,430
Georgia, Virginia, West Virginia	2,270	437	180	37	21	9	2,951
Maryland	1,950	462	167	52	5	96	2,733
South Carolina	2,250	701	312	140	1	87	3,491
Alabama	3,570	662	201	141	16	36	4,621
Kentucky, Mississippi, Tennessee	2,500	383	125	63	11	2	3,087
Arkansas and Oklahoma	1,790	132	565	105	61	8	2,658
Texas, northern	4,960	560	1,070	137	731	228	7,678
Texas, southern	4,240	611	729	204	455	32	6,270
Arizona and New Mexico	2,820	622	238	121	21	145	3,969
Colorado and Wyoming	2,170	314	179	55	65	5	2,786
Idaho, Montana, Nevada, Utah	2,590	238	116	40	228	38	3,245
Alaska and Hawaii	419	65	11	1	--	4	499
California, northern	3,560	279	114	302	--	4	4,257
California, southern	7,330	2,620	351	375	84	3	10,764
Oregon and Washington	1,960	390	178	114	41	3	2,690
Independent importers, n.e.c.[10, 11]	5,220	986	216	206	44	117	6,790
Total[9]	83,800	16,200	7,340	3,820	2,130	1,290	115,000
Puerto Rico	1,090	173	81	527	--	--	1,868
Grand total[9]	84,900	16,400	7,420	4,350	2,130	1,290	116,000

-- Zero.

[1] Includes imported cement and cement ground from imported clinker. Except for district totals, data have been rounded to three significant digits but are likely to be accurate to only two significant digits. District totals are accurate to no more than three significant digits.

[2] District location is that of the reporting facilities and may include sales by them into other districts.

[3] Includes shipments by independent importers for which district assignations were possible.

[4] Grand total shipments to concrete product manufacturers include brick and block—6,390; precast and prestressed—3,580; pipe—2,190; and other or unspecified—4,270.

[5] Grand total shipments to contractors include airport—164; road paving—4,170; soil cement—1,150; and other or unspecified—1,930.

[6] Grand total shipments include oil well drilling—1,800; mining—217; and waste stabilization—116.

[7] Includes shipments for which customer types were not specified.

[8] District totals are not rounded except in accord with the data in table 11.

[9] Data may not add to totals shown because of independent rounding.

[10] Shipments by independent importers for which district assignations were not possible.

[11] Not elsewhere classified.

Source: Van Oss, 2004

ANNEX - AB 32 MEASURES RECOMMENDED AND UNDER EVALUATION

Recommended Greenhouse Gas Reduction Measures						
Measure #	**MEASURE DESCRIPTION**	**REDUCTION (MMTCO$_2$E in 2020)**	**COST ($Millions)**	**SAVINGS ($Millions)**	**Comments on Costs of Major Measures above 1% of total cost**	**Comments on Savings of Major Measures above 1% of total Savings**
					($ million) unless noted	**($ million) unless noted**
	Transportation					
T-1	Pavley I Light-Duty Vehicle GHG Standards	31.7	1,372	11,142	Fleetwide aggregate cost per vehicle of $33-$1,910, 2009-2020. Approximately 1.3 million vehicles per year; annualized over 16-19 years = $1,236; times 1.10 CPI = 1,372	3 billion gallons at $3.67 per gallon = $11,142
	Pavley II - Light-Duty Vehicle GHG Standards		594	1,609	$2,010 cost per vehicle	438 million gallons at $3.67 per gallon = $1,609
T-2	Low Carbon Fuel Standard	16.5	(11,000)	(11,000)		
T-3	Low Friction Oil	4.8	520	954	$20 per vehicle O&M for 26 million vehicles = $520	260 million gallons at $3.67 per gallon= $954
	Tire Pressure Program		49	69		
	Tire Tread Program (Low resistance)		0.6	119.7		
	Other Efficiency (Cool Paints)		360	370	$250 capital costs per vehicle annualized over 14 years = $26 per vehicle, approximately 14 million vehicles = $360	101 million gallons at $3.67 = $370
T-4	Ship Electrification at Ports	0.2	0	0		
T-5	Goods Movement Efficiency Measures	3.5				
	Vessel Speed Reduction		0	86	Need explanation	
	Other Efficiency Measures		0	0		
T-6	Heavy-Duty Vehicle GHG Emission Reduction (Aerodynamic Efficiency)	1.4	1,136	973	$12,000 capital cost per truck annualized over 10 years = $1,600 per truck; 730,000 trucks = $1,136	265 million gallons of diesel at $3.68 per gallon = $973
T-7	Medium and Heavy-duty Vehicle Hybridization	0.5	93	163		
T-8	Heavy-Duty Engine Efficiency	0.6	26	133		
T-9	Local Government Actions and Targets	2.0	200	858	$100 per ton of CO2 reduced = $200	234 million gallons at $3.67 per gallon = $858
T-10	High Speed Rail	1.0	0	0		
	Building and Appliance Energy Efficiency and Conservation					
E-1	Electricity Reduction Program 32,000 GWH reduced	15.2	1,809	4,925	Cost of $119 per ton of CO2 reduced = $1,809	Savings of $324 per ton of CO2 reduced = $4,925
	Utility Energy Efficiency Programs					
	Building and Appliance Standards					
	Additional Efficiency and Conservation					
E-2	Increase Combined Heat and Power Use by 30,000 GWh	6.9	362	1,673	$5,560 capital cost annualized over 30 years = $362 million.	32,000 MWh at $86 per MWh = $2781savings; natural gas consumed

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						for CHP 139,493,000 MMBTU at $7.94 per MMBTU = $1,107 cost. Net savings = $1,673
CR-1	Natural Gas Reduction Programs (800 Million Therms saved)	4.2	420	640	$100 per ton of CO2 reduced = $420	800 million at $0.80/therm $640
	Utility Energy Efficiency Programs					
	Building and Appliance Standards					
	Additional Efficiency and Conservation					
	Renewable Energy					
E-3	RPS (33%)	21.7	3,206	1,650	Cost of $274 per ton from CPUC/E3 modeling	Savings of $141 per ton from CPUC/E3 modeling
E-4	California Solar Programs (3000 MW Installation)	2.1	0	0		
CR-2	Solar Water Heaters (AB 1470 goal)	0.1	0	0		
	High GWP Measures					
H-1	MVACS: Reduction of Refrigerant from DIY Servicing	0.5	60.00	0.00		
H-2	SF6 Limits in Non-Utility and Non-Semiconductor Applications	0.3	0.14	0.00		
H-3	High GWP Reduction in Semiconductor Manufacturing	0.15	2.60	0.00		
H-4	Limit High GWP Use in Consumer Products	0.25	0.06	0.23	$450K Capital Cost for 10 years	
H-5	Low GWP Refrigerants for New Motor Vehicles AC Systems	3.3	15.80	0.00		
H-6	AC Refrigerant Leak Test During SMOG Check	11.6	220.80	0.00	$6 capital cost annualized over 16 years = $0.78; + O&M cost of $220 = $220.78	
	Refrigerant Recovery from Decommissioned Refrigerated Shipping Containers					
	Enforcement of Federal Ban on Refrigerant Release During Service or Dismantling of MVACS					
	High GWP Recycling and Deposit Program Specifications for Commercial and Industrial Refrigeration		1.24	0.66		
	Foam Recovery and Destruction Program		94.83	0.00		
	SF6 Leak Reduction and Recycling in Electrical Applications					
	Alternative Suppressants in Fire Protection Systems		1.96	0.20		
	Gas Management for Stationary Sources--Tracking/Recovery/Deposit Programs		1.02	3.60		
	Residential Refrigeration Early Retirement Program		18.90	24.79		
	Others					

RW-1	Landfill Methane Capture	1.0	0.5	0		
A-1	Methane Capture at Large Dairies	1.0	156	0	$4 capital costs, 330 dairies, annualized over 20 years = $106; + O&M cost of $49.5 = $156	
F-1	Sustainable Forest Target	5.0	50	0		
W-1	Water Use Efficiency	1.4	-	-		
W-2	Water Recycling	0.3	-	-		
W-3	Pumping and Treatment Efficiency	2.0	-	-		
W-4	Reuse Urban Runoff	0.2	-	-		
W-5	Increase Renewable Energy Production	0.9	-	-		
	Total Recommended Measures	***135.5***	***10,771***	***25,394***		

Measures Under Evaluation

MEASURE DESCRIPTION	**REDUCTION (MMTCO$_2$E)**	**COST ($Millions)**	**SAVINGS ($Millions)**	**Comments on Costs of Major Measures above 1% of total cost**	**Comments on Savings of Major Measures above 1% of total Savings**
				($ million) unless noted	**($ million) unless noted**
Transportation					
Feebates for New Vehicles	4.0	594	1,609	Same as Pavley II	Same as Pavley II
Incentives to Reduce VMT	2.0	200	858	$100 per ton of CO2 reduced = $200	234 million gallons at $3.67 per gallon = $858
Subtotal	**6.0**	**794**	**2,467**		
Electricity					
Energy Efficiency (8000 additional to 32,000 GWh Reduced Demand)	3.8	678	1,231	Cost of $179 per ton of CO2 reduced = $678	Savings of $324 per ton of CO2 reduced = $1,231
Calif. Solar Initiative (including New Solar Homes Partnership) Additional 2000MW	1.4	1,348	339	$16,800 capital cost annualized over 20 years = $1,348	3,000,000 MWh at $113.12 per MWh = $339.37
Reduce Coal Generation by 12,800 GWh	8.5	850	0		
Subtotal	**13.7**	**2876**	**1571**		
Natural Gas					

Energy Efficiency (200 million Therms Reduced)	1	179	324	Cost of $179 per ton of CO2 reduced = $179	200 million therms at $0.80 = $324
Residential Solar Water Heater Installation (beyond AB 1470 goal) 2 million	1.2	0	0		
Subtotal	**2.2**	**179**	**324**		
Industrial					
Energy Efficiency and C0-benefits Audits	TBD			$250K for 54 facilities	
Carbon Intensity Standard for Calif. Cement Manufacturers	1.9	19.4	22.8		
Carbon Intensity Standard for Concrete Batch Plants	3.1	0.0	0.0		
Waste Reduction in Concrete Use	1.1	55.0	82.5		
Refinery Energy Efficiency Process Improvement	3.7	71.0	454.0	$762 capital cost annualized over 20 years $61; + $10 O&M cost = $71	56,900,000 MMBtu at $7.98 per MMBtu = $454
Removal of Methane Exemption from Existing Refinery Regulations	0.03	5.0	0.0	$5 O&M cost per year	
Oil and Gas Extraction GHG Emission Reduction	2.0	101.5	276.2	$357 capital cost annualized over 20 years = $23; + $23 O&M cost; + $55 electricity cost = 101.5	33,417,000 MMBtu at $7.98 per MMBtu = $267; + $8.75 O&M Savings = 276.2
GHG Leak Reduction from Oil and Gas Transmission	1.0	19.0	34.2		
Industrial Boiler Efficiency	1.0	22.9	149.7		
Stationary	0.5	17.9	30.6		

Internal Combustion Engine Electrification					
Glass Manufacturing Efficiency	0.1	14.6	8.5		
Off-Road Equipment	TBD				
Subtotal	**14**	**326**	**1,059**		
Total of Measures Under Evaluation	**36**	**4175**	**5421**		
Total	**172**	**14,947**	**30,815**	**Net costs of**	**(15,868)**

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