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October 16, 2015

Mary Nichols, Chairman  
California Air Resources Board  
1001 I Street  
Sacramento, CA 95812

Re: Update the ***"A Cost-effectiveness Analysis of AB 32"*** Study  
authored by Stanford University

Dear Ms. Nichols:

The California Compost Coalition (CCC) is a statewide non-profit trade association comprised of composting and organic materials processing facilities. Our industry, in partnership with local government, has been instrumental in our state's efforts to attain the recycling mandate of 50% waste diversion from landfills, required by the California Integrated Waste Management Act of 1989 (AB 939), and will remain critical to the attainment of future sustainability goals of 75% recycling and the implementation of AB 32. CCC fully supports the AB 939 statutory hierarchy of reducing, recycling, and composting. CCC has been supportive and engaged throughout the AB 32 Scoping Plan development and implementation process to determine the cost effectiveness of greenhouse gas reductions due to composting and anaerobic digestion facility producing carbon negative transportation fuel.

The California Legislative Analyst Office (LAO) reviewed the \$850 million 2014-2015 Budget resulting from the Cap-and-Trade revenue and determined that it was important that proceeds be invested in a way that maximizes GHG emissions reduction given the level of spending, thereby putting downward pressure on the price of allowances and carbon credits. The LAO concluded that the budget lacked a coordinated approach with metrics and oversight in order to evaluate programs and their co-benefits. Plus, the LAO understood that there was no specific guidance on how to compare GHG emissions reductions, as each state department had their own process. The LOA recommended that the Governor may want to increase or decrease funding for specific programs in the future that will maximize GHG emission reductions. We look forward to CARB's leadership on determining GHG reduction metrics by commissioning an update to the 2008 Study titled ***"A Cost-effectiveness Analysis of AB 32"*** authored by Stanford University.

It would be timely for California Air Resources Board adopt, update, and amend a cost-effectiveness study of AB 32 like the one presented by Stanford University. Data from such a study will show that investments in emerging organics waste management technologies for the production of renewable natural gas and compost will make significant and efficient progress towards accomplishing AB 32's mandate.

The CCC has encouraged CalRecycle to take advantage of the flow of information from the Organics Grant Program to analyze the aggregate data received to provide an assessment of the metrics associated with greenhouse gas reductions from organics management approaches. The Cap-and-Trade program raised \$850 million for the 2014-2015 Budget with \$30 million allocated to recycling and composting, \$200 million to low carbon transportation, and \$20 million to improving agricultural efficiency. The allocation was based upon the investment priorities set by the Governor and his Climate Action Team which promoted three key sectors that reduce greenhouse gases: Sustainable Communities & Clean Transportation, Energy Efficiency & Clean Energy, and Natural Resources & Waste Diversion.

Anaerobic digestion with composting is the only program that intersects all three key sectors and should receive greater allocation in the future. On November 7, 2014, CARB held a public workshop on the development of the 2015-2016 budget to allocate the cap-and-trade proceeds towards low carbon transportation. This was the kick-off the to the Governor's budget due in early January 2015 that will allocate an expected \$3 billion to \$5 billion in cap-and-trade revenue.

A 2008 Study titled "A Cost-effectiveness Analysis of AB 32" authored by Stanford University offers a Greenhouse Gas Reduction Supply Curve which compares the marginal abatement costs of various programs in order to ascertain the cost-effectiveness of each. Such a study, if updated to incorporate relevant new technologies, would address the concerns brought forth by the LAO, and provide guidance in moving forward with budget allocation. Within the framework of this initial study, Edgar & Associates performed a marginal cost evaluation of anaerobic digestion and covered compost and determined both to be cost effective, and that both produce enough economic benefits as to actually be socially cost negative over time. A summary of these studies and their implications is provided below and in the attachment.

**Anaerobic Digestion:**

Using the aforementioned assumptions, a typical 25,000 tons-per-year anaerobic digestion system would abate approximately 17,307 MTCO<sub>2</sub>E every year. At the end of its 20 years it would have avoided 90,500 MTCO<sub>2</sub>E worth of emissions. After approximately 18 years, the sale of compost, the avoided tipping fees, and the diesel gasoline savings would make such a project cost-neutral (even given a 5% discount rate, 2% inflation, and regular operating and maintenance costs.) By the end of 20 years, the marginal abatement costs of anaerobic digestion would be -\$50/MTCO<sub>2</sub>E.

**Covered Aerated Static Pile:**

Although Covered Aerated Static Pile Composting systems do not benefit from the fuel savings of anaerobic digestion, lower upfront costs and maintenance expenses make CASP systems comparable to AD in terms of Marginal Abatement Costs. Such systems could be expected to avoid 4525 MTCO<sub>2</sub>E each year throughout their 20 year lifespan. This ultimately results in a total GHG reduction of 90,500 MTCO<sub>2</sub>E, leading to a marginal abatement cost of -\$50/ton. CASP systems reach cost negativity after approximately 11 years.

**Analysis**

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Even in the brief period of time between this study's initial release and today, there have been substantial innovations that have improved the cost-effectiveness of greenhouse gas reduction. Identifying and implementing these improvements to achieve the goals of AB 32 will require new metrics that reflect the technological reality of 2015 and beyond. As the 2020 target date of AB 32 approaches, these new metrics will be essential for realizing the most greenhouse gas reduction per dollar spent.

### **Recommendations**

It is our recommendation that the California Air Resources Board adopt, update, and amend a cost-effectiveness study of AB 32 similar to the one presented by Stanford University. Data from such a study will show that investments in emerging organics waste management technologies will make significant and efficient progress towards accomplishing AB 32's mandate.

In addition to using economic efficiency analysis to select the most efficacious GHG reduction measures, we believe that greater resources should be allotted to waste diversion. The current 3.5% of the 2014-2015 budget that is dedicated to waste diversion, should increase to 5% of the upcoming 2015-2016 budget. This \$150 million would foster the investments necessary to bring the promising new innovations, such as anaerobic digestion and covered composting systems, to eliminate greenhouse gases at the lowest cost.

We feel this is a great opportunity to determine the cost-effective of composting and anaerobic digestion using the grant information that was recently submitted. Please contact me at (916) 739-1200 should you have any questions.

Sincerely,

A handwritten signature in black ink, appearing to read "Evan W.R. Edgar". The signature is stylized and cursive.

Evan W.R. Edgar  
Regulatory Affairs Engineer

cc: Mac Taylor, Legislative Analyst  
Carrol Mortensen, CalRecycle

*DRAFT*

# Analysis of Measures to Meet the Requirements of California's Assembly Bill 32

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*Precourt Institute for Energy Efficiency, Stanford University*



*Discussion Draft September 27, 2008*

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## **Abstract**

This report is intended to provide guidance to policymakers involved in the implementation of California’s Assembly Bill 32 or the “California Global Warming Solutions Act of 2006.” We begin by interpreting the meaning of the phrase *cost-effectiveness* as written in the law, discussing its relation to other policy considerations, and providing preliminary quantification of economic costs of various implementation measures. We present the concept of a *Marginal Abatement Cost curve* for emissions reductions and address how that concept can be used to help inform the policy process. We display the primary result of our analysis: our marginal abatement cost curve for emissions reductions in California in 2020. This curve is the product of many studies of individual measures to reduce emissions in California. Our estimates are drawn from both our review of existing literature and our own analyses. We provide a detailed description of each of our analyses with the goal of contributing to the policy dialogue on Assembly Bill 32.

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## **Acronyms**

AB 32 – Assembly Bill 32

BAU – business-as-usual

BBEES – Big Bold Energy Efficiency Strategy

CARB – California Air Resources Board

CAT – Climate Action Team

CEC – California Energy Commission

CHP – combined heat and power

CIWMB – California Integrated Waste Management Board

CO<sub>2</sub>e – carbon dioxide equivalent

CSI – California Solar Initiative

E3 – Energy and Environmental Economics, Inc.

GHG – greenhouse gas

GW – gigawatt (10<sup>9</sup> Watts)

GWP – global warming potential

GJ – gigajoule (10<sup>9</sup> joules)

IGCC – integrated gasification combined cycle

IOU – investor-owned utility

MAC – marginal abatement cost

MMt – millions of metric tons

ODS – ozone depleting substances

PV – photovoltaic

RPS – renewable portfolio standard

T&D – transmission and distribution

VMT – vehicle-miles-traveled

# **1. Cost Effectiveness and Assembly Bill 32**

## ***1.1. Introduction***

California has been at the forefront of environmental policy in the United States for the past few decades with stringent statewide energy-efficiency and air quality standards often paving the way for national policy several years later. This track record of policy action on environmental goals leading the country has continued with the signing of the “California Global Warming Solutions Act of 2006” by Governor Schwarzenegger on September 27, 2006. This law, Assembly Bill 32 (AB 32, Nunez-Pavley), was designed to establish a comprehensive program of regulatory and market mechanisms to achieve significant reductions in greenhouse gases.

AB 32 builds upon several recent previous environmental policy actions by the California government, such as Assembly Bill 1493 (AB 1493, Pavley), which was passed in 2002 with the goal of reducing passenger vehicle tailpipe emissions; the 2006 Senate Bill 1368 (Perata), which ensures that new long-term financial commitments by electricity service providers to base-load generation will be with power plants at least as clean as combined cycle natural gas plants; the 2004 Executive Order S-8-04 by Governor Schwarzenegger, which designates a “Hydrogen Highways Network” and requires the development of a hydrogen economy blueprint; the 2004 Executive Order S-20-04, which encourages building energy-efficiency; and the 2005 Executive Order S-3-05, which set a target to reduce greenhouse gas emissions in California to 2000 levels by 2010, 1990 levels by 2020, and 80% below 1990 levels by 2050. For these laws and executive orders, the task of determining exactly how to implement the plans and reduce emissions is left to the responsible state agencies.

AB 32 goes further than Executive Order S-3-05 by developing a framework for achieving and enforcing the greenhouse gas emissions reduction target. AB 32 follows the precedent of the previous policy actions by leaving critical elements about the nature and implementation of the policy up to state agencies, with the California Air Resources Board (CARB) taking the lead role. However, AB 32 sets out several major requirements, including:

- CARB must monitor and verify statewide greenhouse gas emissions, through mandatory reporting.
- CARB must adopt a statewide plan to reduce greenhouse gas emissions to 1990 levels by 2020.
- CARB must adopt rules and regulations to achieve “the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions” in furtherance of achieving the statewide limit by 2020.

The first requirement is simple, while the specifics of meeting the second and third require careful thought. Specifically, AB 32 leaves the critical question to CARB: how exactly to meet the emissions limit of 1990 levels by 2020? In addition, AB 32 leaves the details of the third requirement essentially undefined. Thus CARB is left with the interpretation of the question: what does it mean for a set of measures to reduce greenhouse gas emissions to satisfy the requirement of “the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions”? In addition, AB 32 requires, among other things, that the major objectives are met in an equitable way that does not disproportionately impact low-income

communities, and considers overall social benefits of all policies to reduce greenhouse gases. The following sections discuss the interpretation of *technological feasibility* and *cost-effectiveness* and their use in the context of AB 32. From an economic perspective, we elucidate a way of thinking about cost-effectiveness that can be used as a guideline for framing the discussion of how best to implement AB 32.

## ***1.2. What does it mean to be technologically feasible and cost-effective?***

Taken as a whole, we interpret the phrase “technologically feasible and cost-effective” to mean that the rules and regulations must lead to greenhouse gas emissions reductions that are both technologically possible and cost-effective. In the remainder of this section we briefly discuss the meaning of the phrase “technologically feasible” and more fully discuss the meaning of the phrase “cost-effective.”

AB 32 includes no definition of the concept “technologically feasible.” However, in common economic usage, one can interpret the language “technologically feasible” to mean that greenhouse gas emissions reductions must be possible given the technology that will be available at the requisite time of implementation (i.e., by 2020). That technology may be in existence now or it may be developed with sufficient time for implementation prior to 2020. The language could also be interpreted as meaning that the technology must be in existence at the time that the regulations are adopted, thus ruling out technology-forcing regulations. Under either interpretation, “technologically feasible” can be seen as ruling out any solutions that are technologically impossible. In this report we make no attempt to decide which of these interpretations, or other interpretations, is most appropriate.

AB 32 includes a definition of “cost-effective”, but it appears to be only a partial definition. Within its Definitions chapter (Chapter 3, Section 38505) AB 32 includes the following language:

*“Cost-effective” or “cost-effectiveness” means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential.<sup>1</sup>*

This definition defines the basic concept by which cost-effective should be measured (the cost per unit) but does not define the concept of a cost effective reduction. Thus CARB must interpret this partial definition. This need for interpretation is significant because the definition must be used in combination with the language that CARB must adopt rules and regulations to achieve the “maximum technologically feasible and cost-effective reductions.” The exact language is:

*The regulations adopted by the state board pursuant to this section shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit.<sup>2</sup>*

One interpretation is that the word “maximum” is meant to modify the noun “reductions” and the phrase “cost-effective” is meant to limit the reductions by describing what types of reductions are acceptable (cost-effective reductions.) However, were that to be the case, then the definition above does not describe what it means to be a “cost-effective reduction” and thus the

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<sup>1</sup> California Global Warming Solutions Act of 2006. Part 1, Chapter 3, Section 38505.

<sup>2</sup> California Global Warming Solutions Act of 2006. Part 4, Section 38560.5 (c).

phrase “cost-effective” in fact does not limit the reductions. Furthermore, AB 32 requires the emissions reductions to just meet the limit, so the concept of maximum reductions is not consistent with the requirement to meet a particular limit.

Another interpretation is that the word “maximum” was meant to modify the phrase “cost-effective.” But this interpretation taken strictly does not make sense: CARB must adopt rules and regulations that lead to the maximum cost per unit of reduced emissions in furtherance of achieving the statewide limit by 2020. Perhaps, however, the word “maximum” should be changed to the word “minimum”, leading to the interpretation: CARB must adopt rules and regulations that lead to the minimum cost per unit of reduced emissions in furtherance of achieving the statewide limit by 2020. This interpretation is consistent with the definition that we have adopted for this report.

However, absent a clear definition within AB 32, we can turn to the conventional meaning of “cost-effective.” The concept of “cost-effective” has a well-established meaning within the economics profession and a possibly different meaning used within the energy efficiency community. From the welfare economics literature, the phrase “cost-effective” applied to greenhouse gas mitigation policy implies a requirement to minimize the total greenhouse gas abatement cost to society while meeting a specified target emission reduction.

*A set of greenhouse gas mitigation measures is cost-effective under a given target emission reduction if and only if the set of measures together imposes the minimum cost to society (among all possible sets of feasible measures) of meeting the target emission reduction.*

An alternative concept of “cost-effective,” often used in the energy efficiency community within California, would include only those measures that have zero cost or negative cost to the private decision maker. We defer discussion of that concept to a later point in the report. However, we note that in the absence of a cap-and-trade or carbon tax system, this concept is inconsistent with the concept we adopt, and is not an appropriate interpretation of the concept “cost-effective”. However, with a well-functioning cap-and-trade or carbon tax system, this concept would be completely consistent with the concept we adopt.

The definition from the economics profession requires some explanation. The definition is based on minimization of *costs to society* among the set of all *feasible* measures. By the cost to society, we mean the net *social* cost of achieving emissions reductions. **Thus, if there are significant co-benefits (ancillary costs) due to reducing emissions, these benefits (costs) should be included in the net social cost.** For example, co-benefits may include improvements in air quality from reductions of air pollutants that are associated with carbon dioxide emissions.

A feasible measure is one that is possible to implement. In other words, the measure must be technologically feasible. In addition, the measure must be administratively feasible: it must be possible to implement some set of rules, regulations, market incentives, or communication regimes that will lead to implementation of the measure. Other conditions may also be included in the determination of whether a measure is feasible, for example, ethical or legal considerations. These issues will be discussed more fully in a subsequent section of this report.

*Under the established economics definition, an individual measure is considered cost-effective if it is a part of the set of greenhouse gas mitigation measures that together minimizes net cost to society for meeting the defined goal.*

In principle, for an individual measure to be cost-effective, it must not be possible to substitute another feasible measure for the individual measure so as to 1) reduce total cost to society, and 2) continue to meet the target emissions reduction. Substituting another measure could involve a simple switching of measures, whereby a new measure (not already included in the set of measures) replaces the designated measure or measures. Or, substituting another measure could involve the expansion in scope of a measure already included. This would result in an increase in the emissions reductions attributable to that measure, possibly leading to the exclusion of one or more measures initially included in the set of measures.

Within the set of cost-effective greenhouse gas mitigation measures, the costs of the various measures, taken alone, can vary greatly from one to the other. Such a divergence is consistent with the definition of cost-effective, as long as expanding the magnitude or increasing the number of lower cost alternatives either would be not feasible or would be more costly than the implementation of the higher cost measures.

The determination of whether a set of measures is cost-effective requires the consideration of all feasible measures that can be implemented in combination with one another. Thus in principle, final determination of whether any individual measure is cost-effective depends on complete analysis of all possible measures. And in principle, final determination depends on knowing with a high degree of certainty the consequences of the measures that are included among the cost-effective measures as well as those that are not seen as cost-effective.

In practice, however, a complete analysis of all possible measures is rarely practical, so determinations must be made for individual measures absent complete analysis of all possible measures. And in practice, there will remain significant uncertainty about the consequences of various measures. These issues will be discussed more fully in a subsequent section of this report.

Given the wide variety of costs of the various measures, it is useful to introduce the concept of a *marginal abatement cost (MAC) curve* for greenhouse gas emissions reductions (sometimes described as a “supply curve for emissions reductions”). Several recent prominent studies have constructed such curves for national and international greenhouse gas mitigation, most notably the McKinsey Report.<sup>3</sup>

Imagine ordering all feasible greenhouse gas emission mitigation measures from lowest individual cost to the highest individual cost. This ordering includes all feasible measures, whether currently being implemented or not. Each measure is associated with an amount of reductions and a (social) cost per tonne<sup>4</sup> to achieve those reductions. This cost per tonne is the *average* cost per tonne of achieving the given amount of reductions for the individual measure. Within each individual measure, some of the reductions may be less costly than others, but it may be too difficult to differentiate among the various reductions that together are part of a measure. Thus we focus our effort on elucidating the differences in average cost *across* measures and the amount of reductions each measure may achieve.

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<sup>3</sup> McKinsey and Company (2007). Reducing U.S. Greenhouse Gas Emissions: How Much and at What Cost? US Greenhouse Gas Abatement Mapping Initiative Executive Report.

<sup>4</sup> In this paper “cost per tonne” refers cost per metric tonne of greenhouse gas emissions reduction. The shorter phrases “cost/tonne” or “cost per tonne” will be used interchangeably.

Any collection of feasible measures will imply a total amount of reductions (calculated by adding up the reductions from the individual measures) in addition to the costs/tonne of the individual measures. If the feasible measures are ordered from the lowest individual cost/tonne to the highest individual cost/tonne, then the ordering would show, for any total amount of reductions, the cost of the most expensive feasible measure needed to achieve the total reduction.

The *Marginal Abatement Cost curve*, or the *MAC curve*, is this representation of the various total feasible amounts of reductions versus the cost of the most expensive measure needed to accomplish that level of total reductions, with costs ordered from the lowest to the highest individual costs. Figure 1 shows an example of a MAC curve for emissions reductions. To interpret the MAC curve, consider the lowest cost measure, measure A. The width of the rectangle A represents the emissions reductions from this measure, and the net social cost of achieving these emissions reductions is given by the y-axis value attributed to A.

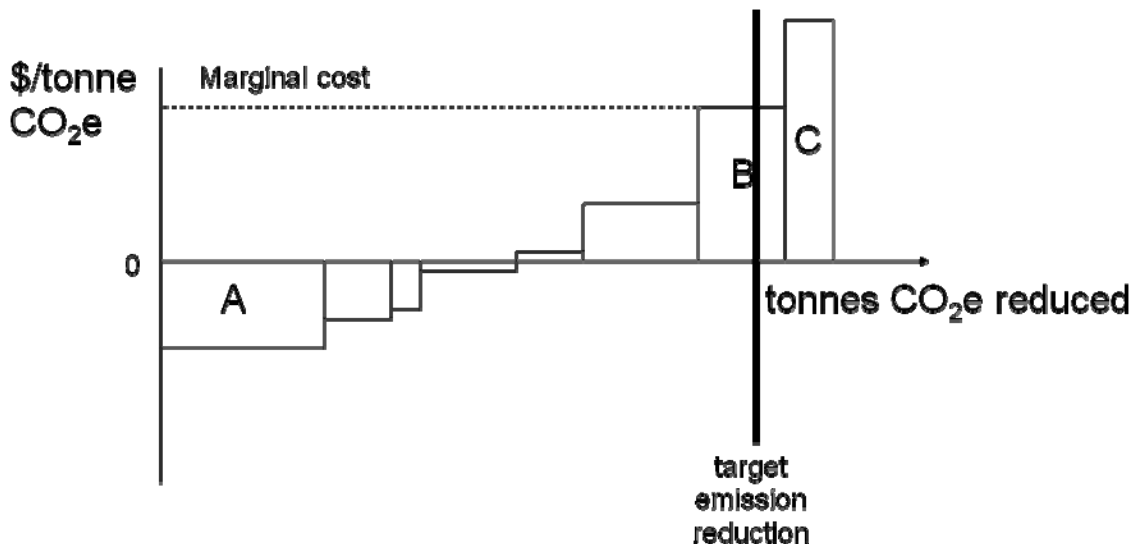


Figure 1. A simple example of a MAC curve for emission reduction measures.

Once a MAC curve is constructed, one can find the total number of measures needed to reach the target level of emissions reduction by drawing a line designating this target (shown above). That total reduction will then imply the cost of the most expensive feasible measure necessary to achieve that reduction in the ordered list of measures. In the example in Figure 1, the most expensive measure needed to meet the limit is measure B. In principle, all measures on the MAC curve having that cost or lower will be cost-effective, while those measures having a higher cost will not be cost-effective.

In addition, for any given target emissions reductions, we can use the MAC curve to estimate how expensive it would be to tighten the target further and reduce one more unit of emissions. The cost necessary to reduce one more unit of emissions is known as the *marginal cost* of emissions reductions. The marginal cost associated with the target emission reduction represents the cost of the most expensive measure in the list of measures needed to meet the target reductions.

We can then describe cost-effective mitigation measures based on these concepts:

*A greenhouse gas mitigation measure is cost-effective under a given target emission reduction if and only if it costs no more per tonne of emissions reductions than the marginal cost associated with the target emission reduction.*<sup>5</sup>

In principle, we can use this description along with the MAC curve to guide policy: we choose an emission reduction target (e.g., sufficient to bring emissions to 1990 levels by 2020), estimate the marginal abatement cost for that level of emissions reductions, and implement all feasible measures to reduce emissions that cost less than the marginal cost associated with the target emission reduction.<sup>6</sup> The chosen measures need not be implemented in order from lowest to highest cost; in fact, it may be administratively much more sensible to implement these chosen measures in an entirely different order.

The California government could use many different methods to implement the greenhouse gas mitigation measures, including direct regulatory policies, policies setting product specific standards within a class of products, policies allowing market-based trading among a subset of products (e.g. all light duty motor vehicles), a broad-based cap-and-trade system, a carbon tax system, a mixture of the various classes of policies operating separately, or a combination of the various classes of policies working together. In practice, it is not likely that any single mechanism would work for all measures. For example, some low-cost measures may be based on correcting market failures due to lack of, or incomplete, information and would be most easily addressed by mandates or other non-price policies, while others may be simply based on the market price not including the damages due to global climate change (i.e., simple externalities). If we limit the class of policies to only one class of policies, we could still use the framework of the MAC curve for those measures that are feasible under the given class of policies. However, by excluding some measures from the MAC curve, such a limitation would increase the marginal cost associated with the target emission reduction.

If the measures are implemented entirely through a market-based system, such as a cap-and-trade system, and the market operates perfectly, the marginal cost associated with the target emission reduction would also represent the market equilibrium price of emissions allowances (per tonne of greenhouse gas) that would result from the target emissions reductions. In a mixed system of regulations applied to some sectors and cap-and-trade applied to other sectors, the market equilibrium price of emissions would be no greater than the marginal cost but may be significantly less. The price would be less if the highest cost of measures in the sectors to which the cap-and-trade system applied were smaller than the marginal cost associated with the entire target emission reduction. The market price could also be lower if appropriate policy tools,

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<sup>5</sup> The choice of the cost-effective set of measures can be formulated more rigorously as a mathematical optimization problem: minimize the sum of costs of the chosen measures under the constraint that the sum of emissions reductions is at least as great as the target reduction level. Using standard mathematical optimization concepts, there will be a shadow price (also called dual variable or Lagrange multiplier) per tonne of emissions reductions. This shadow price will be exactly the marginal cost associated with the given emissions reduction. If this shadow price, multiplied by the amount of emissions reduction, is included as a benefit of the emissions reduction, then all cost effective measures will have non-negative net benefits (non-positive net costs). This leads to the conclusion: a greenhouse gas mitigation measure is cost-effective under a given target emission reduction if and only if it costs no more per tonne of emissions reductions than the marginal cost associated with the target emission reduction.

<sup>6</sup> Note that a measure being included in a report or currently implemented does not imply that the measure is cost-effective. Only measures having a cost less than the relevant marginal cost are cost-effective.



including regulations and incentives, are successfully used to capture any negative-cost and low-cost measures that face non-price barriers to implementation (e.g., energy efficiency improvements may fall into this category) and therefore may not be captured under a cap-and-trade program.

### **1.3. Additional welfare economic concepts**

This section clarifies two important welfare economic concepts that have bearing on our understanding of what it means for a measure to be cost-effective: zero cost and negative cost measures, and economic efficiency.

#### **1.3.1. Zero cost and negative cost measures**

An alternative concept of “cost-effective” often used in the energy efficiency community within California, would include only those measures that have zero cost or negative cost either to all of society or to the private decision-maker. If we examine this alternative concept by looking at measures that have zero cost or negative cost *only to the private decision-maker*, then absent a broad-based cap-and-trade or a carbon tax system applied to greenhouse gases, we reject this concept of “cost-effective” as not appropriate for application to AB 32 analysis. AB 32 was needed because private decision making did not include the costs of greenhouse gas releases. Cost-effective is *not* the same as having no cost.

However, even absent a broad-based cap-and-trade or a carbon tax system, this alternative concept of “cost-effective” *based on all of society* could be appropriate for application to AB 32 analysis, but only if we measured the social cost per tonne of greenhouse gases as equal to the marginal cost in California of greenhouse gas reductions. But it would be only by coincidence that the marginal cost and the social cost would be the same.

However, as will be discussed fully, once a broad-based cap-and-trade or a carbon tax system is applied to greenhouse gases, then this concept of zero or negative cost will become identical to the concept we have been using, including the carbon price in the calculations of overall cost of the measure.

In California, this alternative concept has often been used in policy discussions. For example, the California Public Utilities Commission in its energy efficiency policy aims to implement all “cost-effective” energy efficiency measures, where a “cost-effective” portfolio of measures is defined as a portfolio that as a whole provides net benefits from both societal and utility consumers’ perspectives.<sup>7</sup> In the absence of a broad-based cap-and-trade or carbon tax system, such an alternative concept can be expected to include only a subset of those measures that are “cost-effective” under the more conventional concept used in this paper.

Importantly, our definition from the economics literature of whether to characterize a measure as cost-effective depends on the target emissions reductions. If we implement only those mitigation measures that have zero or negative cost, these measures would be cost-effective under some particular target. Similarly, a broader set of measures would be cost-effective under a more stringent target, say the target with a marginal cost/tonne of \$10. An even

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<sup>7</sup> California Public Utilities Commission (2007). Energy Efficiency Policy Manual, Version 3.1m R.06-04-010: A6-7. The cost-effectiveness tests are defined in California Public Utilities Commission (2001). California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Management Programs..

broader range would be cost-effective with a more stringent target, say characterized by a marginal cost/tonne of \$25.

Thus in the absence of a broad-based cap-and-trade or carbon tax system, the set of zero-cost or negative-cost measures is likely to be a subset of those measures that are cost-effective if the target marginal cost were \$25 per tonne.

The alternative concept does have important uses for policy, even in the absence of a broad-based cap-and-trade or carbon tax system. Because the marginal cost will be positive, the measures characterized by zero-cost or negative-cost will be cost-effective under whatever marginal cost in fact characterizes the AB 32 targets. Therefore, actions can be taken to implement all zero-cost or negative-cost measures with no fear that these measures would not be determined to be cost-effective.<sup>8</sup>

However, once a broad-based cap-and-trade or carbon tax system (one that covers all the emissions of greenhouse gases in California) is implemented, then the two concepts will be completely equivalent if the price in the cap-and-trade system is just equal to the marginal cost associated with the target emission reduction. If the measures are implemented through a market-based system, such as a cap-and-trade system, and the market operates perfectly, the marginal cost of each individual measure that would be profitable to undertake would be smaller than the carbon price, which in turn would be equal to the marginal cost associated with the target emission reduction.<sup>9</sup> Likewise, each measure that would be unprofitable to undertake would have a marginal cost higher than the carbon price. Therefore, if market forces were working perfectly, then all measures with marginal cost smaller than the carbon price would be undertaken and all measures with marginal cost larger than the carbon price would be rejected. Under the cap-and-trade system the target would be just met. Thus the market price of the emission allowance would be just equal to the marginal cost associated with the target emission reduction.<sup>10</sup> Under a well-functioning cap-and-trade system, therefore, all of the chosen measures would have zero or negative net costs from the perspective of the private decision maker, when the carbon price, multiplied by the emissions reduction, is included as a benefit (a negative cost.) All of the rejected measures would have zero or positive net costs, when the carbon price, multiplied by the emissions reduction, is included as a benefit (a negative cost.)

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<sup>8</sup> The one limitation is for measures that are mutually exclusive. Two measures are mutually exclusive if implementation of one precludes implementation of the other. If two measures are mutually exclusive, then a cost-efficient set of measures would include the lower cost of the two mutually exclusive measures. It is possible that both measures have negative cost. In that case, implementation of the negative cost measure with the less negative cost would not be cost-effective.

<sup>9</sup> Note that this refers to the California market price, not the carbon price any place else, for example, the European price. The market price is determined entirely by the target emission reduction, and therefore the European price does not necessarily reflect the marginal cost in California under the AB 32 emissions target.

<sup>10</sup> This can be interpreted in terms of the mathematical optimization problem discussed above. The market price for carbon (the carbon price) will be just equal to the shadow price (dual variable or Lagrange multiplier) per tonne of emissions reductions. If this carbon price, multiplied by the amount of emissions reduction, is included as a benefit of the emissions reduction, then all cost effective measures will have non-negative net benefits (non-positive net costs). This leads to the conclusion: A greenhouse gas mitigation measure is cost-effective under a given target emission reduction if and only if it costs no more per tonne of emissions reductions than the carbon price associated with the target emission reduction.

In this situation, the alternative concept of “cost-effective” – select all measures that have zero cost or negative cost to the private decision maker (and only these measures) – is completely equivalent to the more conventional concept that is being used in this report<sup>11</sup>.

This idea remains valid even when there are some measures that will not respond perfectly or even at all to a carbon price. (These might include situations in which the individual has only limited information about the opportunities for reducing carbon emissions.) For these measures, regulatory interventions would be required even with a carbon price. However, for these cost-effective measures the net cost, including as a negative cost the emissions reductions multiplied by the carbon price, will be zero or negative.

Thus, if a cap-and-trade system for carbon emissions is introduced and the carbon price from that system is included in calculating net costs, then the alternative concept of cost effective is identical to the concept used throughout this report.

### **1.3.2. Economic efficiency**

Many climate change policy analyses are based on the idea of maximizing “economic efficiency.” Maximizing economic efficiency is usually taken to mean choosing the optimal level of emissions reductions to maximize the difference between the total environmental (and other) benefits of the reductions and the total cost of achieving the reductions. Equivalently, if we know the incremental environmental damages in dollars per tonne of greenhouse gas emitted, we can also solve for the optimal level of emissions reductions by finding the emission reduction on the MAC curve corresponding to a marginal cost equal to the incremental environmental damage.

The concept of economic efficiency can be connected to our definition of cost-effective: **all measures with a cost/tonne no greater than the marginal cost at the optimal level of emissions reductions would be cost-effective for that level of emissions reductions.** Thus, if the set of measures is economically efficient, it will be cost-effective for the optimal level of emissions reductions.

Although the economically efficient set of measures will be cost-effective, a set of measures that is cost-effective may not be economically efficient. There is not a single set of cost-effective measures: for progressively greater levels of emissions reductions, there will be progressively broader groups of cost-effective measures. Thus 1) the economically efficient set of emission reduction measures will be cost-effective, 2) there will be many different sets of cost-effective measures for different levels of emissions reductions, and 3) only one level of emissions reductions will be economically efficient.

In the case of AB 32, the emission limit is codified into the law. There is no assurance that the level of emissions reductions is consistent with economic efficiency. Under AB 32, the requirement for “cost-effective” measures is thus not a requirement for choosing economically efficient measures. Rather, analysis must be about meeting the reductions needed to meet the specified limit at lowest societal cost.

It may be argued – and we would strongly argue – that for the US or the world as a whole, the concept of economic efficiency should underlie the choice of the emission reduction target.

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<sup>11</sup> Note that this assumes that all externalities other than the carbon externality have already been internalized. If they have not been, then the calculation must include those other externalities.

Thus this concept may provide some additional guidance in the choice of US or international intermediate emission reduction targets before 2020 and possible future emission reduction targets after 2020.

However, the concept of economic efficiency depends on the environmental damages per tonne of emission. The magnitude of these damages for the world is greater than for the US, which in turn is greater than for California. Thus even with complete knowledge of the costs of the measures, the economically efficient level of emissions reductions will depend upon whether we count reductions in damages for the entire world, for the US, or for California. Determining the appropriate geographic scope of damages to consider would require further discussion before the concept of economic efficiency could be used for unilateral California policy making.<sup>12</sup>

Considering the many complications involved with precise calculations of the economic efficiency of greenhouse gas reduction measures, the California Legislature's decision not to monetize the value of reducing greenhouse gas emissions is reasonable. The Legislature determined as a matter of policy that the state should significantly reduce its greenhouse gas emissions, and it deferred to CARB to determine the most cost-effective and socially beneficial measures to achieve this policy objective.

#### ***1.4. Complicating factors***

In practice, developing a MAC curve is complicated. Uncertainty along many levels makes it difficult to determine exactly the set of cost-effective measures. Implementing some measures may affect the cost of other measures; some measures may make it less expensive to implement others, while some measures may not be as viable in the presence of other measures. Furthermore, there may be other factors that affect the viability or desirability of different mitigation measures, such as equity implications and administrative effort. Each of these will be addressed in turn.

##### *Uncertainty*

There are several layers of uncertainty that influence and complicate the determination of cost-effective measures and the associated policy debate. One way to look at uncertainty in cost-effectiveness is through the lens of two inherent uncertainties for each measure: uncertainty in the cost of achieving reductions and uncertainty in the quantity of reductions possible. The underlying bases for both of these uncertainties are: (1) uncertainty in the development of new technologies, (2) the possibility of other regulations or policies that may influence some of the measures, and (3) the precision or accuracy of estimation. Moreover, there is uncertainty in business-as-usual emissions, so even the target emission reduction needed to meet the 2020 limit is only a best estimate. Combined, these uncertainties imply that any estimated MAC curve should be viewed not as an exact estimate, but rather with implicit error bars around the estimate.

Given these uncertainties, we are left with the critical question: *what do these uncertainties mean for policymaking?* The answer depends on the nature of the uncertainty.

The first possibility is that only the estimated costs of some measures are in error, but the rankings of the measures from lowest to highest cost and the quantities of emissions reductions

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<sup>12</sup> Similarly, determining the economically efficient level of emission reduction for any geographic area is difficult to do precisely, given the uncertainties associated with the anticipated environmental, health, and economic impacts of global warming.

from each measure are nonetheless accurate. In that case, uncertainty in the cost would not lead to uncertainty in the set of cost-effective measures. Since the target level of emissions reductions is fixed and the ordering of the measures from lowest to highest cost is accurate, which measures would be cost effective could be determined accurately, even with cost uncertainty. However, the total cost of achieving those reductions would be uncertain.

The second possibility is that quantities of emissions reductions from each measure are uncertain, but that the rankings of the measures from lowest to highest cost are known accurately. In that case, uncertainty would lead to possible errors in determining which measures are cost-effective. Suppose the estimated MAC curve of anticipated emissions reductions turns out to be optimistic, and the actual feasible reductions are significantly smaller than estimated. In that case, the set of cost-effective measures should include more measures than was originally estimated. That is, the evaluation would exclude some measures that would in fact be cost-effective. Conversely, if the estimated MAC curve is pessimistic, the evaluation would include some measures that in fact would not be cost-effective.

The third possibility is that the relative costs of the various measures are uncertain, so that the ordering from lowest to highest cost is uncertain. In that case, the assessment could include some measures that were not cost-effective while excluding others that in fact were cost-effective.

If there is uncertainty about quantities of emissions reductions from various measures or uncertainty about the relative costs of the various measures, then the requirement that California must meet the AB 32 target and the requirement that the set of measures must be cost-effective can be difficult to reconcile.

Finally, the business-as-usual (BAU) baseline emissions are inherently uncertain. The AB 32 emissions limit is fixed, and thus the emissions reductions needed to meet the limit are dependent on the BAU emissions. Depending on whether the BAU emissions are over- or under-estimated, the required emissions reductions may be significantly different than the estimated emissions reductions. For example, if the CARB preliminary estimate of BAU emissions in 2020 of 596 MMt CO<sub>2</sub>e is off by 5%, the needed reductions to reach the limit of 427 MMt CO<sub>2</sub>e could be as low as 109 MMt CO<sub>2</sub>e or as high as 229 MMt CO<sub>2</sub>e, rather than the expected value of 169 MMt CO<sub>2</sub>e reductions.<sup>13</sup>

Given that such uncertainty can be expected to remain, California can choose policies that are likely to meet the AB 32 target and are likely to be cost-effective. And it can choose policies that will have total costs that are very close to the costs of the actual (but unknown) cost-effective set of measures. But, absent perfect information – which California will never achieve – it is impossible to assure that the set of measures both will meet the AB 32 target emissions and be cost-effective. However, CARB can make conservative assumptions for the various estimates discussed above that are inherently uncertain to increase the likelihood that the set of measures both will meet the target emissions and be cost-effective.

#### *Cost-effectiveness and “packaging”*

In describing cost-effective emission reduction measures, we are referring to all distinct measures that have a single quantity reduction and associated per-tonne cost that together impose

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<sup>13</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

the minimum cost to society of meeting the target emission reduction. For the MAC curve to be accurately constructed, a “package” of measures that can be described by a single average cost, but that in fact can be separated into several distinct measures must be separated into separate measures. Such a separation could influence the set of measures that are determined to be cost effective. In particular, as long as some of the distinct measures have costs that exceed the marginal cost of carbon reductions, those distinct measures are not cost effective, even if the average cost of the package of measures has an average cost lower than the marginal cost of carbon reductions.

However, in some cases the implementation of one measure may affect the cost of other measures. Some measures may be much less expensive when implemented with others. These measures are *complementary* measures. For example, implementing smart growth measures may reduce the cost or increase the effectiveness of expanded mass transit in reducing emissions. Conversely, some measures may be more expensive or even become unviable when other measures are implemented. These measures are *substitutable* measures. Any measures that compete against each other are substitutable, in some part or entirely. For instance, a measure to promote electric battery vehicles may compete against a measure to promote hydrogen fuel cell vehicles, so that the emissions reductions from each of the two measures when both are implemented are less than the emissions reductions from each measure on its own.

Understanding circumstances with complementary or substitutable measures can be important in constructing a MAC curve for emissions reductions. While separable measures should be included in the MAC curve individually, complementary measures may be included as a package, if the cost of the measures is close. If the measures have very different costs, it is preferable to separate out the costs, but reduce the costs of the more expensive measures to account for the fact that the complementary measure has already been implemented. Substitutable measures can be dealt with similarly. Once the least costly measures are included in the MAC curve, more expensive measures can be included in the MAC curve taking into account the fact that the substitute measure has already been implemented. This would increase the estimated marginal cost of the more expensive measures.

### *Feasible measures*

The description of cost-effective includes the idea that all *feasible* measures less than the marginal cost associated with the target emissions reductions are considered cost-effective. For a measure to be feasible it must be technologically feasible. But, feasibility also implies that measures must meet other reasonable criteria for policies. AB 32 specifically requires CARB to ensure that implementing regulations achieve various objectives including not disproportionately impacting low-income communities, not interfering with achievement of air pollution reduction requirements, minimizing administrative burden, minimizing leakage, etc.<sup>14</sup>

In addition to these, another criterion not explicitly mentioned is that a measure must not only minimize the administrative burden, but must be administratively feasible. A measure that appears to cost less than the marginal cost associated with the target emissions reductions, but would be impossible to administer should not be considered feasible, and thus would not be cost-effective. Alternatively, the administrative costs can be included in the cost of emissions

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<sup>14</sup> California Health and Safety Code. [Section 38562\(b\)](#).

reductions for the measure, so that measures with sufficiently high administrative cost would not be considered as cost-effective.

Many of the legislatively defined criteria, while independent in their own right, can also be thought of as manifestations of the concept that a measure must not lead to sufficiently undesirable equity implications. For example, if a measure costs less than the marginal cost associated with the target emissions, but puts a disproportionate burden of the costs on lower-income or minority households, then, because of equity considerations, such a measure might not be considered as feasible. Equity considerations may also be important if one industry or sector is facing a disproportionate burden from implementing the cost-effective measures. It may be possible to implement ancillary measures to reduce the objectionable equity issues; if so, the cost of these ancillary measures should be included in the cost of the measure of interest. If such ancillary measures are not possible, then the measure of interest might not be considered cost-effective.

#### *Further limitations of MAC curves*

Before moving on to presenting the MAC curve that resulted from our analysis, it is worth noting a few final points of caution about the use of MAC curves. One issue relates to uncertainty: MAC curves can be quite sensitive to the baseline assumptions of the analysis. For instance, changing the assumed future fossil fuel prices can considerably change the cost-effectiveness of many transportation measures. Similarly, since MAC curves are made up of separate analyses of many measures, it can be a difficult, yet critical, task to assure that the analyses of different measures are consistent.

Another issue with using MAC curves is that they ignore any general equilibrium effects, where policy affecting one market influences prices throughout the economy and can have a ripple effect on other markets in the economy. One well-known example of a general equilibrium effect would be if AB 32 raises the price of fossil fuels enough to raise the average price level in the economy. Since real wages decline if the average price level throughout the economy rises, workers will supply less labor in the economy, exacerbating the pre-existing distortion from the income tax (i.e., the tax on labor).<sup>15</sup> Thus, through a price feedback, a policy on one market (the market for fossil fuels) can have larger effects.

These limitations and difficulties of MAC curves may be quite important over a long time frame; however, in our judgment, we believe that the MAC curve is a reasonable approach in the near term in relatively smaller geographic areas, as is the case with California and AB 32 2020 emissions limit.

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<sup>15</sup> Bovenberg, L. and L. Goulder (2000). *Neutralizing the Adverse Industry Impacts of CO2 Abatement Policies: What Does It Cost? Behavioral and Distributional Impacts of Environmental Policy*. C. Carraro and G. Metcalf. Chicago, University of Chicago Press.

## 2. Marginal Abatement Cost Curve Estimate

Based on the concepts described above, we performed a variety of analyses on different potential measures to reduce greenhouse gas emissions in California. Many of our analyses draw estimates directly from the available literature about the cost and quantity reductions. Others use the literature as a starting point for our own analysis. Section 3 provides detailed descriptions of these analyses. Figure 2 presents our 2020 MAC curve, which represents our best estimate of the potential greenhouse gas reductions available to California in the next 12 years for any given cost.

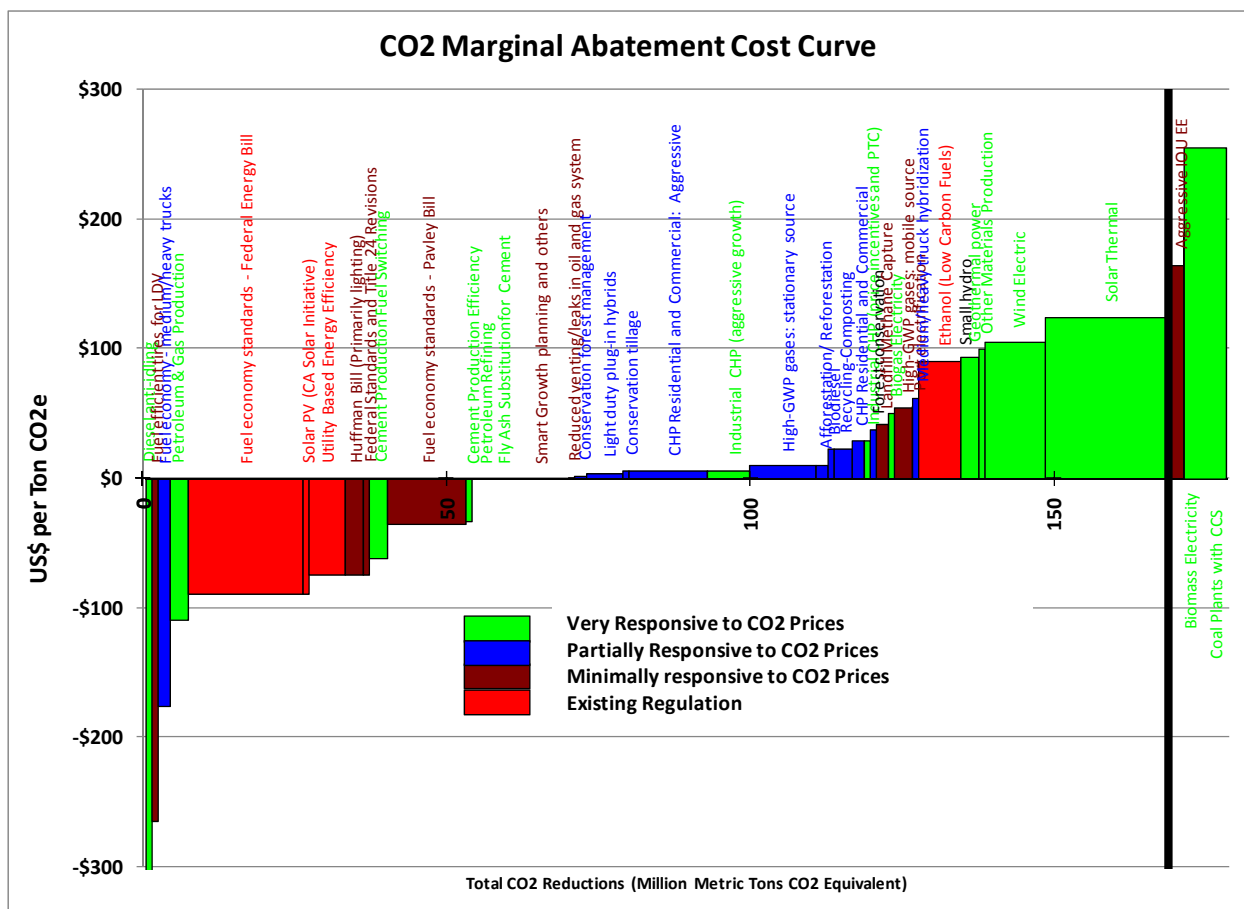


Figure 2. 2020 CO<sub>2</sub> reduction MAC curve as of September 27, 2008

### 2.1. Interpretation of the curve

There are several facets to this curve that warrant clarification. To begin, the general layout of the curve is analogous to Figure 1, with a target emissions reduction given by the thick black line at an emissions reduction of 169 MMt CO<sub>2</sub>e. This corresponds to CARB's assessment of the necessary emissions reductions in 2020 to achieve the AB 32 target of 427 MMt CO<sub>2</sub>e. In



effect, for this analysis we are adopting the CARB 2020 business-as-usual emissions of 596 MMt CO<sub>2e</sub>.

Just as in Figure 1, the width of each block in the curve represents our best estimate of emissions reductions, and the height of each block represents our best estimate of the average cost of achieving those emissions reductions. As described above, within each measure some of the emissions reductions may be less costly than the average cost per tonne for the entire measure, but by the nature of the measure these less costly measures cannot be easily isolated.

The next facet of the curve to be emphasized is the color scheme. This color scheme is designed to differentiate those measures that to the best of our judgment would likely be responsive to a market-based policy that appropriately priced carbon (e.g., a cap-and-trade or carbon tax system), from those measures that are less likely to respond to a market-based policy. The latter class of measures includes those that are not price responsive as a result of market failures other than the greenhouse gas externalities (e.g., informational market failures). For these measures, even if carbon dioxide is correctly priced, the measure still might not occur – implying that other policies are likely to be necessary to implement these measures. Green represents those measures that are likely to respond fully to carbon prices, dark red represents measures that are only minimally responsive to carbon prices, blue represents measures that are partially responsive. We also color-code existing policies separately, since these measures will not require any additional action by CARB beyond continued implementation. Bright red represents such measures.

The MAC curve can be used provide policy guidance in two ways. First, it provides an outline for the measures that CARB should examine most closely in implementing AB 32. Those measures to the left of the target emissions reduction are, in our best estimates, those measures that are most likely to be cost-effective given the target emissions reduction.

Second, the color-coding provides a first approximation in differentiating between those measures that can be implemented through a cap-and-trade system or a carbon tax and those measures that are less responsive to such a market-based system. Those measures that are very responsive to carbon prices (green color) can be implemented through a cap-and-trade system or a carbon tax with no need for additional greenhouse-gas-related regulatory intervention, unless there are other important unpriced externalities associated with those measures.<sup>16</sup> Those measures that are minimally responsive to CO<sub>2</sub> pricing (dark red) are very likely to require additional policy actions to achieve the desired emissions reductions. Such policies deserve additional policy analysis and are likely to require policy instruments in addition to a carbon tax. Those that are partially responsive (blue) might require complementary policies in addition to carbon pricing but may respond enough with simply a carbon price and voluntary actions, so that additional regulatory responses may not be needed.

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<sup>16</sup> For example, some measures may reduce the emissions of greenhouse gases and simultaneously reduce the emissions of toxic wastes or other important pollutants. If the negative consequences of these toxics or other pollutants are not priced (that is, if they remain as externalities that are not internalized), then a cap-and-trade system might not motivate reductions that would be cost-effective. In that case, unless the cap-and-trade system were augmented by some intervention that internalized the cost of these co-pollutants, the cap-and-trade system could not assure that such cost-effective measures would be implemented.

## 2.2. Conclusions using the MAC curve

There are a few important conclusions to take from this MAC curve. One primary conclusion is that if we read from left to right along the horizontal axis, we can see the measures that in our best estimate have the lowest cost per tonne CO<sub>2</sub>e reduced and are thus most likely in our estimation to be cost-effective. The curve reveals that there are likely to be many negative cost measures, but to meet the AB 32 target emissions reduction, CARB will have to consider implementing many measures that in our estimation have positive costs. The curve also reveals that the total cost to society before accounting for the benefits from reducing greenhouse gases may well be positive, for the positive area under the curve to the left of the target emissions reduction appears to be slightly larger than the negative area under the curve at the far left. But once we account for the benefits of reducing greenhouse gases, even with this small positive cost, the overall policy is worthwhile. However, the analysis suggests that the emissions reductions are likely to come with some cost; they are not likely to be costless in aggregate.

Another conclusion is that the marginal cost of implementing AB 32 may exceed \$100 per tonne CO<sub>2</sub>e. As described in Section 0, the marginal cost is the additional cost of one more unit of CO<sub>2</sub>e reductions. We can see this on the curve by noting the height of the block through which the target emissions passes. This marginal cost is within the range of some estimates of the environmental damages of global climate change.

This marginal cost would correspond to the market price of carbon dioxide under a market-based system if all of the measures to the left of the target emissions reduction are implemented.

It is important to distinguish the marginal cost per tonne of CO<sub>2</sub>e marginal cost from the *average cost* of emissions reductions, which is the total cost of emissions reductions divided by the total reductions. Since the total cost appears to be positive but small, the average cost would be just slightly positive,<sup>17</sup> perhaps around \$10 per tonne of CO<sub>2</sub>e.

A final conclusion from our MAC curve is that existing regulation captures several of the largest measures, and that the remaining measures are evenly distributed between measures that are more likely to be responsive to a price on CO<sub>2</sub> and measures that are less likely to be responsive. It also appears that several of the measures that are less likely to be responsive are lower-cost measures on the curve, suggesting that CARB should examine additional policy interventions to achieve these low-cost measures.

It should be noted that most of the emissions reduction from negative cost measures are based on measures that have already been mandated based on laws other than AB 32. For example, Federal fuel efficiency standards and the California-specific greenhouse gas standards of the Pavley bill are already being implemented independently of AB 32. Thus the cost of implementing the additional measures undertaken under AB 32 (that is, in addition to measures already mandated under other Federal or state law) is likely to be higher than suggested by adding up costs of all measures together. This graph shows that it is highly unlikely that the overall cost of these additional measures would be negative.

Examining the curve, two of the largest negative-cost measures are the 2007 Federal Energy Bill fuel economy standards and AB 1493 (Pavley) vehicle greenhouse gas standards. However, there is an important interaction between the California restrictions and the newly configured

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<sup>17</sup> It is very unlikely, but not impossible, that the average cost will ultimately turn out to be negative.

Federal fuel economy (CAFE) standards. The Federal fuel economy standards require automakers meet a national fleet-wide average fuel economy.<sup>18</sup> It is unlikely that the automakers will exceed the federal standards. Thus, unless either enough other states also adopt the standards or the Federal government adopts the standards, there will be a very high level of leakage, if not 100% leakage. Any emissions reductions from the policy in California are likely to be offset by additional emissions in other states, with the automakers just meeting on average the federal CAFE standards.

Another notable block is the 11 MMT CO<sub>2</sub>e emissions reductions from smart growth. We search the literature to determine a reasonable estimate, but it is very difficult to determine what the potential savings truly would be.

This is actually the case for several of the measures, which leads to a critical point:

*Our MAC curve estimate is not intended to be taken as the final word on the subject, but rather a starting point for further discussion and analysis.*

The estimates of the emissions reductions and cost-effectiveness of each the measures in our MAC curve are based on our best analysis, given the available data and the time frame we had to perform the analysis. Not only are there ways to further improve each of the analyses, but different assumptions about deep uncertainties, such as future oil prices, future electricity prices, and California economic growth, would change the results of our analysis and could shift our MAC curve. Similarly, there is room for additional analysis of which measures are complementary or substitutable – we have kept this in mind throughout the analysis, but have not always been able to operationalize the relationships between different measures.

We intend our MAC curve and the supporting analyses to spark discussion and contribute to the policy process. *The concept of including all measures to the left of the target emissions reduction is evocative, but* we recognize that it is by no means is the only consideration in the policy process, as discussed in Section 0. The following section provides detailed supporting documentation for our estimates that make up the MAC curve.

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<sup>18</sup> More precisely, it is gallons per mile that is averaged. That leads to a control on the harmonic mean weighted value of miles per gallon.

### 3. Supporting Documentation

#### 3.1. Key assumptions

In the following sections, we describe in detail the methodologies used to compute the emission reduction and cost-effectiveness estimates in our MAC curve. The spreadsheet models containing relevant calculations are available upon request.

A few broader assumptions are made throughout the analyses that are worth mentioning first. For one, we use a discount rate of 5%. While there is no consensus in the literature on the most accurate discount rate to use, a social discount rate of 3% and a private discount rate of 6-10% is a common assumption. A second common assumption is the price of electricity in 2020. We base our modeling of measures to reduce emissions in the electricity sector on work done by the consulting company Energy and Environmental Economics, Inc (E3).<sup>19</sup> Thus for the rest of the analyses we base our estimates of 2020 electricity price used by E3 under the mid-level assumption of energy efficiency and a \$60 per tonne CO2 carbon price, which is 15.7 cents per kWh. Unless otherwise noted, all dollar values are in 2006 dollars.

All other assumptions are noted within the documentation for each of the measures.

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<sup>19</sup> See E3's website at [www.ethree.com](http://www.ethree.com) for further information.

### 3.2. Energy Efficiency Programs: Electricity and Natural Gas

Table 1. Summary estimates for energy efficiency programs for electricity and Natural Gas

Measure	Emission Reduction (MMt CO <sub>2</sub> e)	Costs (\$/tonne CO <sub>2</sub> e)
Industrial Sector	1.16	-\$74
Residential	2.10	-\$74
Commercial Sector	1.68	-\$74
Huffman Bill	3.71	-\$74
Title 24 + Federal Standards	1.08	-\$74
BBEES	0.67	-\$74

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#### 3.2.1. Background

Reducing the demand for electricity and natural gas by increasing the efficiency with which energy is used can be a cost effective means to generate significant reductions in carbon emissions. Over the years the state of California has implemented a number of measures aimed at increasing energy efficiency, and today the state leads the nation in the creation of legislation and regulations aimed at encouraging efficiency enhancing technologies and programs. The spread of energy saving technologies and processes has been encouraged by a number of programs actively implemented by state utilities (primarily the larger, investor owned utilities), as well as through the creation of legislation, regulations and standards that incentivize or require the adoption of energy saving practices. In this section we review existing work to better understand both the extent of CO<sub>2</sub> reductions that might be achieved by improving efficiency, as well as the costs of such reductions.

One of the more comprehensive studies of energy efficiency potential for California has been carried out by the consulting firm Itron. Two separate Itron reports form the basis of the numbers discussed here. The first of these is the California Energy Efficiency Potential Study, (draft final report), dated May 2008.<sup>20</sup> The second is the Itron Scenario Analysis to Support

<sup>20</sup> Itron (2008). California Energy Efficiency Potential Study, Draft Final Report submitted to Pacific Gas & Electric Company, Itron Inc and KEMA Inc.

Updates to the CPUC Savings Goals.<sup>21</sup> The first of these is a detailed study of the savings potential and costs of implementing investor owned utility (IOU) programs under different scenarios. The second report builds upon this work and presents estimates of energy savings potential from both IOU programs as well as other sources such as federal codes and standards. This work also forms the basis of the energy efficiency potential figures embedded in the E3 Greenhouse Gas Calculator.<sup>22</sup>

Following the classification pattern used by the Itron report (and the E3 model), we look at energy efficiency savings as arising from the following three sources:

- investor owned utility programs
- strengthened codes and standards (including Title-24 and Huffman Bill)
- ‘Big Bold Energy Efficiency Strategy’ (BBEES).

Each of these three sources will be described in turn.

#### *Investor owned utility programs*

Investor owned utility programs have proved to be an effective driving force for the implementation of energy efficiency measures and technologies in the state, especially where these measures are not mandated by federal or state regulations. IOU programs are expected to be the source for a significant fraction of the cumulative savings potential through 2020. There are a large number of technology measures that are either currently incentivized by utilities, or are viable candidates to be included in the utility program portfolio, and the reader is encouraged to refer to Itron (2008) for more details on the composition of the IOU program portfolio.

We base the savings and cost estimates presented here upon the outputs from Itron’s ASSET model, corrected to account for the presence of strengthened codes and standards. Such a correction is required because as increasingly more stringent codes and standards are put in place, energy saving behavior that is now mandated by the state is no longer available as a source of savings for utilities to exploit. Thus, as standards are strengthened, additional savings from utility programs grow harder to find (though this slowdown in IOU savings growth is mitigated by the increase in savings from the adoption of standards). These interactions make it important to estimate the savings potential from energy efficiency as a whole, in order to maintain internal consistency and in order to avoid double counting. The Itron Scenario Analysis report (2008), which draws upon the 2008 potential study (Itron 2008), provides a set of internally consistent scenarios that also forms the basis for the efficiency potential embedded in the E3 greenhouse gas calculator. In this report we use these numbers as our primary source.

#### *Strengthened codes and standards (including Title-24 and Huffman Bill)*

Efficiency savings owing to strengthened codes and standards encompass the effect of the implementation of AB 1109 (the Huffman Bill), strengthening of Title 20 and Title 24 standards and the revision of federal appliance standards. These savings also account for the implementation of revised minimum energy efficiency standards following the rulemaking

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<sup>21</sup> Itron (2008). Scenario Analysis to Support Updates to the CPUC Savings Goals, Report submitted to the CPUC, Itron Inc.

<sup>22</sup> Model and documentation available at [www.ethree.com/cpuc\\_ghg\\_model.html](http://www.ethree.com/cpuc_ghg_model.html)

schedule listed in the Five-Year Schedule of Issuance of Appliance Rulemakings.<sup>23</sup> As documented in Itron (2008), these revised standards apply to a variety of appliances: clothes dryers, dishwashers, residential CAC, residential RAC, commercial packaged terminal air conditioners (PTAC), and commercial packaged terminal heat pumps (PTHP).

### *The 'Big Bold Energy Efficiency Strategy' (BBEES)*

The phrase 'Big Bold Energy Efficiency Strategy' refers to a set of programmatic initiatives defined by Commissioner Grueneich in her April 13, 2007 scoping ruling. They consist of "strategies to promote maximum energy savings through the coordinated actions of utility programs, market transformation and codes and standards."<sup>24</sup> Four programmatic areas have been identified for initial consideration – residential new construction, commercial new construction, industrial programs and HVAC.

For a more detailed discussion of each of these sources the reader is encouraged to consult the Itron scenario analysis report (Itron 2008b). The remainder of this discussion is organized as follows. In Section 3.2.2, we review the methodology used by the Itron studies to estimate the savings potential from utility programs. This section includes definitions of the various scenarios used to describe utility program savings. We present savings and abatement estimates and costs from the implementation of IOU programs alone, uncorrected for the influence of other components of overall energy efficiency (such as changing standards and the Huffman Bill). The numbers in this section are meant to be illustrative of the effect of different scenarios. They do not form the final abatement estimates and costs from energy efficiency that we recommend for the MAC curve, because they incorporate only uncorrected savings from utility programs. This background proves useful later however, when we discuss summarized estimates of overall efficiency savings potential and costs.

### *Municipal utility programs*

Municipal utility programs are analogous to investor-owned utility programs, and are included in the E3 analyses.

In Section 3.2.3 we present these aggregated estimates of CO<sub>2</sub> reductions and energy savings from all the various sources of energy efficiency considered here (including but not restricted to utility programs). This section draws upon the integrated scenarios in the Itron Scenario Analysis report (Itron 2008). Section 3.2.3 also contains cost estimates to achieve these abatement amounts, based on the E3 Greenhouse Gas Calculator and the Itron (2008) potential study. The numbers in this section thus represent our current estimates of the abatement potential and costs from increasing energy efficiency. Section 3.2.4 discusses the limitations of our analysis based on the Itron report and future steps that could improve the confidence we have in our estimation of efficiency savings potential and costs.

## **3.2.2. Review of Itron estimates of savings from investor owned utility programs**

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<sup>23</sup> US Department of Energy (2006). Five-Year Schedule of Issuance of Appliance Rulemakings. Available at: [http://www.eere.energy.gov/buildings/appliance\\_standards/pdfs/five\\_year\\_schedule.pdf](http://www.eere.energy.gov/buildings/appliance_standards/pdfs/five_year_schedule.pdf).

<sup>24</sup> California Public Utilities Commission (2007). Order Instituting Rulemaking to Examine the Commission's Future Energy Efficiency Policies, Administration, and Programs - Assigned Commissioner's Scoping Memo and Ruling on Issues Relating to Future Savings, Goals, and Program Planning for 2009-2011 and Beyond. Available at: [http://docs.epuc.ca.gov/cyberdocs/WebQuickstart.asp?DOC\\_ID=E4285](http://docs.epuc.ca.gov/cyberdocs/WebQuickstart.asp?DOC_ID=E4285).

Approximately 30% of CO<sub>2</sub> emissions in California come from heat and electricity generation. Four investor owned utilities generate three quarter of all electricity in California: Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), Southern California Edison (SCE), and Southern California Gas Company (SCG). Publicly-funded utility incentive programs to improve end-use efficiency have driven significant reductions in electricity and gas consumption in the last decade and will make up a major share of cumulative savings through 2020. It is therefore not surprising that there exist detailed estimates of the potential savings that can be achieved through IOU programs. Such forecasts have been constructed using a database of hundreds of individual measures by Itron and similarly detailed estimates have been generated by the California Energy Commission as part of their load forecasts. In this section we discuss the Itron model outputs (Itron 2008).

We should reiterate that the abatement figures in this section are not corrected for the influence of other aspects of energy efficiency (such the imposition of more stringent appliance and building standards that would then reduce some of the measures that utilities could use to achieve savings targets). The discussion in this section is therefore meant primarily to serve as a brief overview of the approximate potential that could be tapped under various scenarios through utility programs. They also help to make the point that there are significant CO<sub>2</sub> reductions from a naturally occurring baseline that can be captured at negative costs. The final results that serve for our MAC curve are presented in Section 3.2.3 and include other sources of energy efficiency and use utility estimates that are corrected for the influence of these other components.

Before proceeding further, Table 2 presents definitions of concepts used for energy-efficiency analysis. These terms are largely derived from the Itron (2008) efficiency potential draft report.

Table 2. Useful definitions for energy-efficiency analysis	
Concept	Definition
<b>Avoided costs</b>	<b>Avoided costs</b> are defined as the cumulative costs the utility avoids incurring as a result of implementing a measure. These costs include energy costs, transmission and distribution costs, line losses, environmental costs, etc.
<b>Cost-effective</b>	A greenhouse gas mitigation measure is considered <b>cost-effective</b> under a given target emission reduction if it costs less than the marginal cost associated with the target emission reduction. Note that this definition is not the same as used for the overall AB 32 analysis.
<b>Measure costs</b>	<b>Measure costs</b> are the per unit costs incurred by the utility when a particular energy saving measure is made a part of their portfolio of programs, due to incentives offered, but excluding the utility program costs. That is, measure costs are the fraction of incremental costs to consumers that are paid for by the utilities as part of their incentive scheme.
<b>Total Costs</b>	<b>Total Costs</b> are defined as the sum of utility program costs and measure costs. Measure costs used are the full incremental cost (which implies the utilities are providing full incentives).
<b>Total Resource</b>	<b>Total Resource Cost (TRC) Ratio</b> The Itron report uses a TRC test as a



<b>Cost (TRC) Ratio</b>	proxy for profitability, in order to separate energy efficiency measures into those that have net negative costs when incentivized by the utility and those that have positive costs. The TRC ratio is defined as the ratio of avoided costs to measure costs.
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It should be noted that a TRC criteria for picking measures differs from a metric of cost-effectiveness that evaluates a measure's cost relative to the marginal costs for such a reduction in emissions. Rather, restricting measures to only those with a TRC > 1 effectively leaves only those that are of negative or close to zero net cost to the *utility*. In general, the set of energy savings measures that are cost effective from the point of meeting AB 32 goals would exceed the set that is profitable to the utility alone. The latter is a much narrower constraint.

*Itron study*

The focus of the California Energy Efficiency Potential Study (Itron 2008) was to estimate the remaining electricity and natural gas potential savings in new and existing residential, commercial, and industrial sectors, accessible through IOU programs. The study provided forecasts for the effects of energy efficiency measures from publicly-funded utility programs for two time periods; the near future from 2007 to 2016 and the foreseeable future from 2016 to 2026. Energy savings estimates do not take into account potential changes in consumer behavior or measures requiring major redesign of an existing system.

The study analysis utilized ASSET, a model developed by Itron. The ASSET model takes inputs from utility data, customer data, and technology data. Utility data includes program costs, avoided costs, and demand side management program features. Customer data includes adoption-related behavior (awareness, willingness, etc.), usage profiles, and segment data. Technology characteristics include emissions data, costs and lifetimes, and characteristics by segment. Efficiency measure impacts and costs come primarily from the Database for Energy Efficiency Resources (DEER),<sup>25</sup> while measure lifetime information comes from the CPUC Policy Manual.<sup>26</sup>

*Itron scenario definitions*

Outputs from the Itron study include estimates for energy savings potential under many scenarios. While a full discussion of the scenarios modeled is available in both Itron (2008) and Itron (2008), Table 3 summarizes the scenarios pertinent to our analysis.

Scenario	Description
<b>Naturally Occurring</b>	The Naturally Occurring scenario is an estimate of the energy savings that would occur with natural market forces, assuming that no <i>further</i> measures are incentivized by utilities. Naturally-occurring potential thus includes

<sup>25</sup> Itron (2005). 2004-2005 Database for Energy Efficiency Resources (DEER) Update Study: Final Report, Prepared for Southern California Edison.

<sup>26</sup> California Public Utilities Commission (2007). Energy Efficiency Policy Manual, Version 3.1m R.06-04-010: A6-7.

	savings from measure adoptions due to free-riders, participant and non-participant spillover, and longer-term market effects.
<b>Market Full Restrict</b>	The market full scenario is an estimate of energy savings, under <i>market</i> conditions, with the utility paying <i>full</i> incremental costs of program measures, but <i>restricting</i> incentivized measures to those that pass a TRC test ( $TRC > 0.85$ ). Current market forces, such as account customer cost-effectiveness, payback period, awareness and willingness to adopt, are assumed to remain constant.
<b>Economic</b>	The economic scenario is a theoretical benchmark referring to the maximum savings potential that would be achieved if measures were installed in all feasible applications with TRC ratio $> 1$ . This scenario assumes that all customers adopt cost-saving technology (i.e. 100% market penetration) and is therefore not achievable in practice. However the economic scenario is useful as a benchmark against which to compare the success of programs. In some sense the difference between the economic and market scenarios represents the additional savings that could be achieved by expanding programs to achieve higher market penetration (albeit at the price of exponentially increasing program costs).
<b>Technical</b>	The technical scenario provides the savings potential that would be captured if all available energy efficiency measures were installed in all feasible applications at a 100% penetration rate. The technical scenario is also an entirely theoretical and unachievable benchmark.

In the analysis that follows, we have chosen the Naturally Occurring scenario as a baseline representing a base case projection. The Market Full Restrict scenario represents the expected energy savings from a fully-incentivized program of measures that are profitable to the utility. For this analysis, we chose the ‘Full’ scenario (one where the utilities pay the full incremental cost of measures) for two reasons. First, such a scenario is expected to result in higher adoption levels of incentivized measures because the upfront costs to consumers are reduced. Secondly, in a situation where utilities pay all incremental measures costs, **the difference between costs and benefits to the utility more closely approximate social costs.** Subtracting Naturally Occurring from Market Full Restrict yields the expected benefit in terms of energy savings (CO<sub>2</sub> reductions) from the fully-incentivized program.

*Itron estimates: IOU abatement quantities and costs*

The estimates in this section come from the summary results in the 2008 Itron report and from the database containing the comprehensive data used to create the summary reports. The former provides useful summary values for each run in years 2016 and 2026, but no explicit data for the year 2020. The Itron database includes specific cost and savings values for every measure for every year for each scenario. This added precision allowed for more detailed analysis and explicit calculations for the year 2020. Using the database (the Market Full Restrict run and the Naturally Occurring run, both for the year 2020), we also computed savings at the level of individual measures. This is useful in determining which end use sectors have the most potential for energy use reductions (see Table 4).

Abatement potential from IOU programs alone, not accounting for changing regulatory standards or the effect of legislation such as the Huffman bill on program portfolios, is estimated as amounting to 7.32 million metric tons (MMt) for the year 2020.<sup>27</sup> This amount comes from the CO<sub>2</sub> emissions difference between Naturally Occurring and Market Full-Restrict scenarios. The 7.32 MMt represents the amount of emission savings expected if utilities fully incentivize all measures with near net zero costs (TRC ratios > 0.85), assuming current customer willingness and market forces. This value, which we calculated by summing across all measures in the Access output data, is satisfactorily consistent with the value estimated by linearly interpolating between the 2016 and 2026 outputs explicitly provided in the Itron (2008) potential report.

The following table breaks down the Market Full Restrict potential by TRC ratio ranges and end-use sector.

Table 4. Emission reduction potential for the market full restrict scenario.				
	Million Metric Tons CO <sub>2</sub> Reduced			
TRC	<b>Residential</b>	<b>Commercial</b>	<b>Industrial</b>	<b>Total</b>
<b>0.85 &lt; 1.5</b>	0.45	0.89	0.50	1.83
<b>1.5 &lt; 2.5</b>	1.08	1.02	0.38	2.48
<b>&gt; 2.5</b>	1.12	0.46	0.45	2.03
			<b>Grand Total:</b>	<b>6.34</b>

Table 4 shows that 2.03 MMt could result from measures with large cost-savings (TRC > 2.5), 2.48 MMt from measures with TRC between 1.5 and 2.5, and 1.83 MMt from measures with TRC between 0.85 and 1.5. The remaining CO<sub>2</sub> savings to make up 7.32 MMt come from voluntary consumer adoption of measures with TRC < 0.85.

An additional 8.9 MMt CO<sub>2</sub> could hypothetically be achieved if no market barriers existed, i.e. assuming full market penetration. This value corresponds to the Economic potential minus the Market Full Restrict potential, as interpolated from the Itron report values for 2016 and 2026. Removing both the market penetration restriction and the measure cost restriction (TRC > 0.85) corresponds to the Technical run. Beyond the Economic potential, this run adds approximately 7.2 MMt of saved CO<sub>2</sub>. Again, this value was interpolated from the 2016 and 2026 values in the Itron report. These additional savings come from measures that have higher than net zero costs and by assuming full market penetration. The Economic and Technical scenarios are essentially theoretical benchmarks and the costs of achieving all this potential is indeterminately high. However, some fraction of this increment may be obtainable at positive costs per ton CO<sub>2</sub>.

<sup>27</sup> Assuming CO<sub>2</sub> savings at the rate of 395 metric tonnes per GWh and 5000 metric tonnes per MTherm

We move now from our discussion of the CO<sub>2</sub> reductions achievable through utility programs, to the important question of the *costs* involved in obtaining these reductions. Our best current estimates of costs come from the E3 Greenhouse Gas Calculator and are discussed in Section 3.2.3.

Before discussing those numbers however, we should point out that the Itron model suggests extremely substantial cost savings are achievable through the implementation of utility programs at a full incentive level (refer to definitions). The Itron (2008) draft report (see pp. 111), provides the following cost figures:

<b>Scenario</b>	<b>PDV Net Measure Costs</b>	<b>PDV Gross Program Costs</b>	<b>PDV Net Electric Avoided Cost Benefits</b>	<b>PDV Net Gas Avoided Cost Benefits</b>
Full Restrict	8,740	1,434	14,971	2,735

These costs correspond to outputs from a model run under the Market Full Restrict scenario (as used earlier in Table 4 in our discussion of abatement amounts). Total costs over the 2007-2026 period work out to approximately 10.13 billion dollars, while the corresponding benefits in avoided costs to the utility, over the full time frame to 2026, are about 17.7 billion dollars. These figures cannot, of course, be applied to CO<sub>2</sub> reductions obtainable over the period until 2020 (net monetary savings would be lower if 2020 was chosen as the cut-off year instead of 2026), but they make the point that there is a sizeable amount of carbon reduction that these programs can engender, while making large savings. In other words, the 2008 Itron report states that the overall TRC for the complete statewide portfolio of energy efficiency savings under their model (ASSET), over the period from 2007-2026 is about 1.74 (in the case where utilities provide full incentives).

The implications of these numbers are significant for the overall effort of determining how to achieve AB-32 goals. A TRC as high as 1.74 seems to suggest that there should be more savings possible in return for greater expenditures, albeit with diminishing returns. It also highlights a limitation of current studies and one that we return to in the next section. It is true that there exists a sizeable amount of information on the characteristics of different measures that utility programs could encourage, as well as highly sophisticated models such as the Itron ASSET model. However, these resources have largely been used so far to help utilities plan (the Itron report being an example), and not to determine measures needed to achieve AB-32 goals.

In the context of utility portfolios, the TRC is a good metric to use to evaluate a set of measures and the goal of achieving TRC levels greater than 1.00 makes sense. However, when determining how much of a contribution energy efficiency can make to achieving AB-32 goals, the natural metric to use is costs per unit carbon saved and the watermark of relevance is determined by the cost effectiveness criteria. For that reason, it would be ideal to have model runs which allow for positive cost energy efficiency measures (which would fail the TRC test currently being used in the Itron model), to enable the construction of a MAC curve for energy

efficiency. This would enable us to estimate how much more of a reduction we could ‘squeeze out’ of energy efficiency measures, were we willing to pay more. In the next section we go into this question in greater detail.

### 3.2.3. Energy efficiency potential and costs

#### *Emissions reductions*

A model that considers energy efficiency in the context of AB-32 goals is the E3 Greenhouse Gas calculator. The E3 model contains a set of scenarios of varying levels of energy efficiency savings, based on the Itron Scenario Analysis report.<sup>28</sup> This report estimates savings owing to IOU programs, as well as strengthened codes and standards, and the implementation of the so-called, ‘Big Bold Energy Efficiency Strategy’ plan.

The Itron Scenario Analysis report, defines a set of scenarios composed of energy efficiency from IOU programs, savings owing to strengthened codes and standards (Title 24 and appliance standards), savings from the implementation of the Huffman Bill and finally energy use reductions from the implementation of the BBES plan. These scenarios assume utilities offer full incentive levels with TRC restrictions in place (see Market Full Restrict scenario definition in Section 4.1.2). IOU savings have been adjusted to take into account the presence of codes and standards. The Low, Mid and High estimates incorporate a sensitivity analysis on certain uncertain parameters such as market penetration rates. For more details, and for other scenarios, please see Itron 2008b. The Itron numbers have been supplemented with estimates of savings from municipal utilities in the E3 Greenhouse Gas Calculator. Table 6 presents these cumulative abatement forecasts, from the E3 model, through 2020. The E3 reference scenario is the baseline used by the E3 model, and corresponds to the savings embedded in the CEC demand forecasts.

In determining which scenario is an appropriate target it is important to estimate both marginal and average costs of abatement for each of the three cases. In essence, these three scenarios are a crude approximation of an underlying smooth MAC curve of energy efficiency measures. In choosing an appropriate level of savings to aim for, it is therefore necessary to know not just the average cost under each scenario, but also the *marginal* cost of moving from one level to the next. The cost of the incremental savings achieved when moving from one level to another (for example, Mid to High) must therefore pass our cost effectiveness definition in order to be implemented. With that in mind, we move from a description of the carbon savings under these scenarios to the crucial issue of determining the MAC curve they trace out.

Table 6. Integrated abatement quantities from energy efficiency measures<sup>29</sup>

EE Savings Source	E3 Reference (CEC Embedded Savings)	Low Estimate	Mid Estimate	High Estimate
<b>Electricity Savings (GWh)</b>				
<b>BBES Initiatives</b>	-	1693	2183	3288

<sup>28</sup> Itron (2008). Scenario Analysis to Support Updates to the CPUC Savings Goals, Report submitted to the CPUC, Itron Inc.

<sup>29</sup> Based on E3 Greenhouse Gas Calculator (see EE tab of the E3 model): E3. (2008). "E3 Greenhouse Gas Calculator." Retrieved August 20, 2008, from [www.ethree.com/cpuc\\_ghg\\_model.html](http://www.ethree.com/cpuc_ghg_model.html).

<b>Huffman Bill</b>	-	9384	5493	7283
<b>Title 24 Revisions + Federal Standards</b>	-	2724	4058	4669
<b>IOU Programs - Electric Utility</b>	16450	13869	21318	21318
<b>IOU Programs - Gas Utility</b>	-	187	320	419
<b>Total GWh Savings</b>	<b>16450</b>	<b>27857</b>	<b>33372</b>	<b>36977</b>
<b>Gas Savings (MTherm)</b>				
<b>Total Mtherm Savings</b>	<b>195</b>	<b>286</b>	<b>460</b>	<b>587</b>
<b>Gross Abatement Amounts (Million Metric Tons)<sup>30</sup></b>				
<b>Gross CO2 Abatement</b>	7.47	12.43	15.48	17.54
<b>Naturally Occurring Abatement<sup>31</sup></b>				
<b>Naturally Occurring GWh Savings (Itron Estimate)</b>	4107	4107	5662	8483
<b>Naturally Occurring Mtherm Savings (Itron Estimate)</b>	85	85	106	128
<b>Naturally Occurring CO2 Abatement (MMtonnes)</b>	<b>2.04</b>	<b>2.04</b>	<b>2.76</b>	<b>3.99</b>
<b>Net CO<sub>2</sub> Abatement (Million Metric Tons)</b>				
<b>Net Abatement</b>	<b>5.43</b>	<b>10.39</b>	<b>12.72</b>	<b>13.55</b>

### *Integrated cost estimates*

A limitation of the Itron Scenario Analysis<sup>32</sup> is that the development of cost estimates was not a part of the scope of this work and (as we have previously discussed) the cost estimates in the 2008 potential study have limitations when applied to our present purpose. They are also restricted to measures implemented as part of IOU utility programs alone.

The only integrated cost estimates that we are aware of therefore, are those that are embedded in the E3 Greenhouse Gas calculator. The E3 numbers are based in part on cost estimates provided by Itron to E3 of the IOU program component of the “low, mid and high” scenarios that form part of the E3 model.<sup>33</sup> These costs are supplemented in the E3 model with other assumptions about the costs of mandates and non-IOU programs. For the present this also forms the best knowledge we have of the costs of achieving efficiency based abatement. That said, there is a need to come up with IOU program costs geared to the requirements of a study such as ours (perhaps based on the ASSET model, which does contain the detailed information

<sup>30</sup> Assuming 275 metric tons CO<sub>2</sub>/GWh and 5000 metric tons CO<sub>2</sub>/Mtherm

<sup>31</sup> Based on estimates in Itron Scenario Analysis report. The figures for the E3 Reference Scenario are approximate, assuming similar savings to the Low Scenario case

<sup>32</sup> Itron (2008). Scenario Analysis to Support Updates to the CPUC Savings Goals, Report submitted to the CPUC, Itron Inc.

<sup>33</sup> Mahone, A. (2008). Personal Communication.

needed to carry out this task). Such estimates would probably require lowering IOU portfolio TRC's under the scenario runs documented in Itron<sup>34</sup> from current levels that are well above 1.0,<sup>35</sup> to thresholds chosen on the basis of meeting the criteria of cost effectiveness as defined in this report. In addition, there is a need for documentation and discussion of the methodology used to estimate the costs currently being used by the E3 model.

Table 7 and Figure 3 provide cost estimates from the E3 model for five scenarios. The reference case scenario is the baseline for the E3 model while three are based on the Itron Low, Mid and High goals, with the final one being based on Mid goal with a 33% Renewable Portfolio Standard (RPS). The E3 reference roughly corresponds to the savings embedded in the CEC demand forecasts. All scenarios in this table with the exception of the 33% scenario are assumed to be implemented under a business as usual (20%) renewable portfolio standard. RPS goals can change the costs or benefits from energy efficiency savings. This is partly because the net costs of efficiency measures depend on the avoided costs of generation on the part of utilities, which in turn are influenced by other factors such as the extent to which renewables are used for power generation. For example, as the table shows, implementing Mid goals and mandating a 33% RPS standard, would increase costs.

Table 7 also allows us to form a rough MAC curve for energy efficiency. In light of the uncertainty that presently exists around the costs, technical and administrative feasibility of capturing the High scenario savings (and of achieving the increased penetration rates necessary to make the High scenario a reality), it seems reasonable to regard the Mid scenario as an achievable target. However, whether or not the Mid level goals are in fact cost effective as per our definition is a separate question that needs to be determined. In this case, based on the costs in Table 7 the Low scenario can be seen to be achievable at an average cost of -\$74 per metric tonne of CO<sub>2</sub>. The Mid scenario provides an additional 2.33 tonnes, but average costs (for 12.72 MMt) go up to -\$30 per tonne. The incremental 2.33 tonnes obtained by shifting from Low to Mid are thus made available only at a very high marginal cost, about \$165 per tonne CO<sub>2</sub> in this case. Based on these numbers therefore, it is only cost effective to shift from Low to Mid savings when all measures available at marginal costs below about \$165 have been exploited.

The E3 model suggests that incremental savings from the High scenario, over and above the Mid scenario, could be achieved at relatively low additional costs. However the High scenario is associated with other uncertainties and represents an aggressive estimate of market penetration, consumer adoption and the effectiveness of different efficiency measures. At present therefore we have chosen to restrict ourselves to examining the Mid scenario. As more information becomes available and greater experience is gained with efficiency measures (particularly emerging technologies such as those envisaged in the BBEES), it may become reasonable to include the High scenario as well. With RPS levels held at 20%, the high scenario would provide an additional 3.16 MMt over the Low scenario and the marginal cost over the Low scenario would be slightly lowered, to about \$151 per tonne CO<sub>2</sub>. Of course in the context of the overall curve, this is still a high figure.

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<sup>34</sup> Itron (2008). California Energy Efficiency Potential Study, Draft Final Report submitted to Pacific Gas & Electric Company, Itron Inc and KEMA Inc.

<sup>35</sup> For example the overall TRC for IOU portfolios, as detailed in the Itron 2008 potential study, is about 1.74, for a full incentive case restricted to measures with TRC > 0.85.

It should be pointed out that the numbers in Table 7 are aggregate energy efficiency costs including both IOU costs as well as costs of implementing codes and standards, lighting regulations and so on. We are still in the process of working with E3 and Itron to determine appropriate disaggregated costs for each of the different components of energy security. We refer the reader to Section 3.1.3 for a discussion of the fraction of savings coming from IOU programs, and the cost of achieving those savings. As discussed, there are likely significant savings that can be achieved at negative social costs from IOU programs. There may be positive costs to implementing codes and standards or the Big Bold Energy Efficiency strategy. Overall, there is room to improve our understanding of the costs of energy efficiency measures of all kinds.

Table 7. Cost estimates from the E3 model, five scenarios

<b>S.No</b>	<b>Scenario</b>	<b>Estimated Savings (MMt CO<sub>2</sub>e)</b>	<b>Net Cost (\$/tonne CO<sub>2</sub>)</b>
<b>1</b>	E3 Reference EE (CEC Embedded)	5.43	-\$116
<b>2</b>	Low EE with BAU other	10.39	-\$74
<b>3</b>	Mid EE with BAU other	12.72	-\$30
<b>4</b>	High EE with BAU other	13.55	-\$21
<b>5</b>	Mid EE with 33% RPS	12.72	-\$11



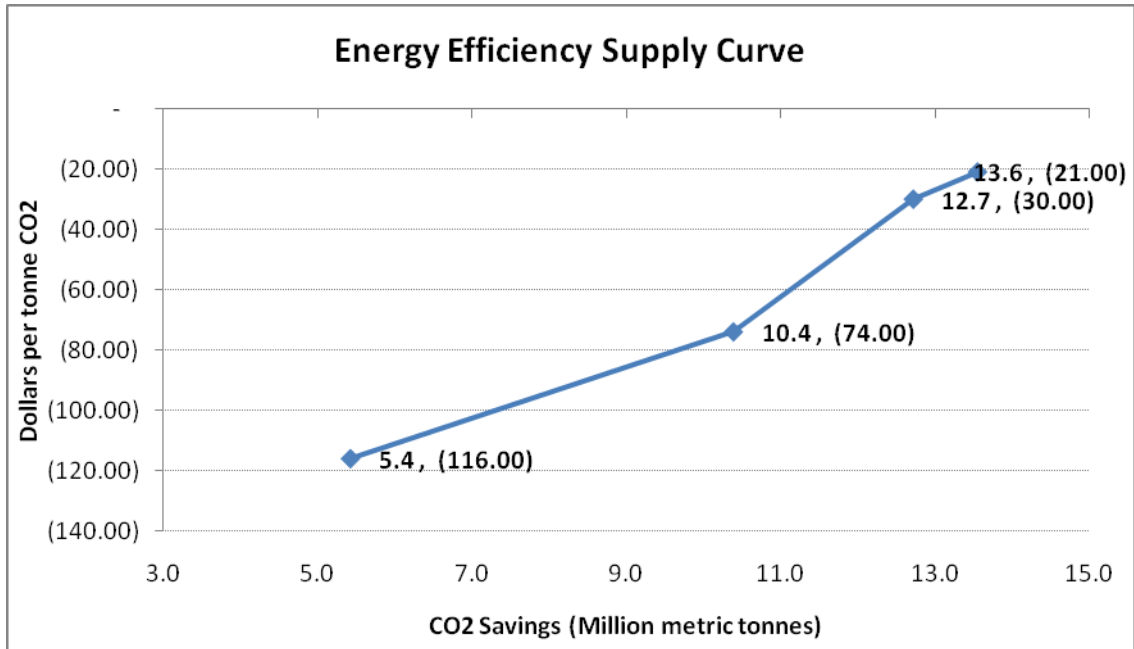


Figure 3. Supply curve for energy efficiency.

### 3.2.4. Limitations and future research

Our analysis has a few limitations. First, values for avoided costs do not incorporate all social benefits of reducing electricity consumption, nor do the cost values include all social costs. For example, additional benefits of reduced air toxin levels result from building fewer power plants. Also, additional costs related to enhancing customer adoption and reducing market barriers may not be adequately known. This factor limits the ability to project costs as penetration rates are increased.

A second issue, which relates to the IOU program potential, is the difference between Itron’s TRC cost criterion and our cost-effectiveness objective. Since all Itron market runs include a restriction of net zero costs (either for the entire program portfolio or for specific measures), they do not allow us to see the abatement potential for costs above zero. Restricting the values of portfolio TRC’s provides an estimate of IOU potential that may be available at negative costs. However, from the point of achieving AB 32 goals, if marginal abatement costs are positive (as our analysis suggests), then further reductions from IOU programs may be needed at positive cost to the utilities. Of course implementing such programs would probably require assistance from the state to the utilities, but nevertheless it is important to understand to what extent additional efficiencies could be achieved if utilities were to increase the costs of their program portfolios.

Another area needing greater discussion is the issue of determining the most appropriate baseline against which to measure the different scenarios. One option is a zero energy efficiency baseline, but this seems an artificial choice given that there is a natural amount of savings due to adoption of more efficient technologies that would occur irrespective of any special efforts. Another option is to attempt to estimate the naturally occurring savings that would occur if IOU programs were not expanded and additional measures penetrated the market only as they would

have absent any special incentives. In addition it is assumed that no new policies come into play creating additional savings. This is a status quo baseline, and corresponds roughly to the naturally occurring savings estimated by Itron. We have used this baseline in this report but it should be pointed out that this is an approximation only. Apart from inherent uncertainties in estimating this quantity, there might be some underestimation introduced since the Itron analysis does not cover municipal utilities. A third option is to use as a baseline, the savings embedded in the CEC demand forecasts. Unfortunately it is not clear that this choice corresponds closely to CARB's baseline for energy efficiency savings. Should this be a desired choice however, the E3 reference scenario can be used as a baseline since the savings represented by that scenario correspond in the E3 model to the savings embedded in the CEC demand forecasts.

A fourth area of some uncertainty has to do with the most appropriate choice of multiplicative factors used to estimate carbon savings from reductions in electricity and gas demand. We use 395 MMt CO<sub>2</sub> per GWh and 5000 MMt CO<sub>2</sub> per Mtherm in this report, but changing these numbers would naturally change the abatement expected and costs per tonne of energy efficiency measures. In particular it should be noted that these estimates will depend on the specific fuel mix used to generate power by utilities and its evolution over time.

Finally, it should be recognized that apart from the IOU programs (for which detailed models do exist), the cost and savings estimates from other components such as the BBEES are far more uncertain. As a consequence, as more information becomes available it is likely that these numbers will gradually evolve.

#### *Future research*

Much of the groundwork necessary to reasonably estimate carbon savings potential from investor owned utility programs has been carried out already. However, there needs to be more effort made towards using available data and the models that have been developed to answer questions of interest to policymakers who are seeking to determine how California should best achieve AB-32 targets. In the context of the ITRON ASSET model, which forms the basis for the estimates reported in this document, we recommend carrying out a series of model runs, similar to those reported in Itron (2008), but without the requirement that only measures passing the TRC test ( $TRC > 0.85$ ) be allowed. This would enable the construction of an energy efficiency curve and allow policymakers to determine the incremental savings that could be obtained, were utilities to reduce their portfolio TRC, possibly even to levels below 1.00.

A second area needing more research has to do with the quantification of the costs of achieving these savings. We are still working on determining the best numbers to use for both IOU efficiency costs, as well as the costs involved in implementing other energy efficiency sources such as the Huffman bill or strengthened federal codes. At this point while there does seem to be a fair degree of data on the nature of IOU program and measure costs, the same cannot be said for the other components of energy efficiency. While some estimates do exist (and have been quoted in this model), the methodology behind them needs discussion and there are probably benefits to be gained from more work on this area.

### 3.3. Transportation sector programs

Table 8. Summary estimates for transportation

Measure	Emission Reduction (MMTCO <sub>2</sub> e)	Costs (\$/tonne CO <sub>2</sub> e)
Light duty fuel economy: 2007 Federal Energy Bill	19.6	-\$89
Light duty fuel economy: AB 1493 (Pavley)	13.7	\$35
Medium/heavy duty fuel economy	1.25	-\$175
Ethanol	6.8	\$90
Biodiesel	0.8	\$23
Light duty plug-in hybrids	6.0	\$62
Medium/heavy truck hybridization	0.5	\$68
Shore Electrification	0.55	\$56
Fuel Efficient Replacement Tires	1.34	-\$264
Diesel Anti Idling	1.46	-\$336

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#### 3.3.1. Light duty vehicle improvements in fuel economy

##### *Background*

The light duty vehicle fleet is the source of nearly a third of the total greenhouse gas emissions in California, and has long been the target of efforts to reduce emissions. AB 32 builds upon this history by placing California Assembly Bill 1493 (Pavley), at the centerpiece of efforts to reduce emissions from the vehicle sector. AB 1493 explicitly provides the authority to the California Air Resources Board (CARB) to develop and adopt regulations that “achieve the maximum feasible and cost-effective reduction of greenhouse gas emissions from motor vehicles.” However, under Section 209(b) of the Federal Clean Air Act, California is required to receive a waiver from the US Environmental Protection Agency to regulate carbon dioxide at the

state-level. As of the date of the writing of this report, this waiver has not been granted, although it is widely expected that the waiver will be granted as soon as the next US presidential administration enters office (e.g., see the CAT (2006) Report).<sup>36</sup>

By CARB setting limits on greenhouse gas emissions from motor vehicles, it is effectively setting a minimum fuel economy that the vehicles must meet, since there is a one-to-one relationship between carbon dioxide emissions and fuel economy. While it is up to CARB to determine the exact carbon dioxide emissions limits (and correspondingly, fuel economy) that AB 1493 will require, CARB's most recent estimates suggest that under AB 1493 by 2020 the harmonic weighted average passenger car fuel economy will be 49.1 miles per gallon (EPA ratings) and for light duty trucks it will be 32.7 miles per gallon (EPA ratings).<sup>37</sup> These estimates are not only greater than a reasonable business-as-usual baseline scenario, but are also greater than latest Corporate Average Fuel Economy Standards contained in the 2007 Federal Energy Bill. CARB's estimates of the 2007 Energy Bill fuel economy standards put the harmonic weighted average passenger car fuel economy at 38.6 miles per gallon (EPA ratings) and 33 miles per gallon (EPA ratings).

Before diving into the emissions reductions and cost-effectiveness, it is important to discuss the actual effect of AB 1493 in the context of the Federal CAFE standards. Since the Federal CAFE standards require automakers to meet a harmonic fleet-wide fuel economy standard, a requirement to improve fuel economy in California would allow automakers to sell less-efficient vehicles elsewhere in the United States and still have their fleet-wide average meet the CAFE standards. Assuming that the Federal CAFE standards are a limiting factor in the production decisions of automakers, this implies that there will be nearly 100% leakage in emission reductions. In other words, nearly all emissions reductions in California due to AB 1493 will be offset by increases in emissions elsewhere in the United States. The Federal CAFE standards are generally considered to be binding (i.e., a limiting factor in production decisions) for all of the domestic automakers and at least some of the foreign automakers, implying that AB 1493 may not achieve any global emission reductions.

CARB acknowledges this possibility, but makes the point that other states are highly likely to follow California's lead by setting the same standards as AB 1493.<sup>38</sup> If enough states adopt AB 1493, then the automakers will be forced to adjust their line-up to AB 1493, leading to real emissions reductions. Moreover, if enough states adopt AB 1493, it is likely that new Federal fuel economy standards will adopt the AB 1493 limits, guaranteeing real emission reductions. For this analysis, we follow CARB in assuming that the emissions reductions in California will be real reductions from diffusion of California policy around the United States. However, we recognize that there will likely be significant leakage from AB 1493, particularly in the first few years after adoption before a sufficient number of other states (or the Federal government) follow suit.

### *Emissions reductions and costs*

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<sup>36</sup> Climate Action Team (2006). Climate Action Team Report to Governor Schwarzenegger and the Legislature. Sacramento, CA, California Environmental Protection Agency.

<sup>37</sup> California Air Resources Board (2008). Comparison of Greenhouse Gas Reductions for the United States and Canada under US CAFE Standards and the California Air Resources Board Greenhouse Gas Regulations. Enhanced Technical Assessment. Sacramento, CA.

<sup>38</sup> Ibid.

As AB 1493 provides one of the largest components of the AB 32 emissions reductions, the Stanford Team developed its own model of emissions reductions and cost-effectiveness. The methodology used differentiates between the emissions reductions from the 2007 Energy Bill Federal fuel economy standards and the additional emissions reductions over the Energy Bill reductions that AB 1493 would provide. Correspondingly, we calculate cost-effectiveness for both the Energy Bill reductions and the additional AB 1493 reductions.

The starting point for the analysis is CARB’s interpretation of the equivalent fuel economy values in each year under the Energy Bill and AB 1493, as described above. These estimates are adjusted to on-road fuel economy values based on the ratio of 2002 values estimated by CARB for California and the on-road fuel economy values forecasted in the VISION-CA model, developed by Marc Molina.<sup>39</sup> The basis for these estimates is the Department of Energy’s Annual Energy Outlook 2005.<sup>40</sup> We compare the estimates of on-road fuel economy under AB 1493 and the Energy Bill to baseline on-road fuel economy estimates using the same growth rate as used in the VISION model (0.8%). These estimates in the VISION model also reference the Annual Energy Outlook 2005. We calculate the fleet-wide on-road fuel economy by assuming the constant fleet percentage used in the CARB comparison report. Figure 4 presents these adjusted fuel economy estimates.

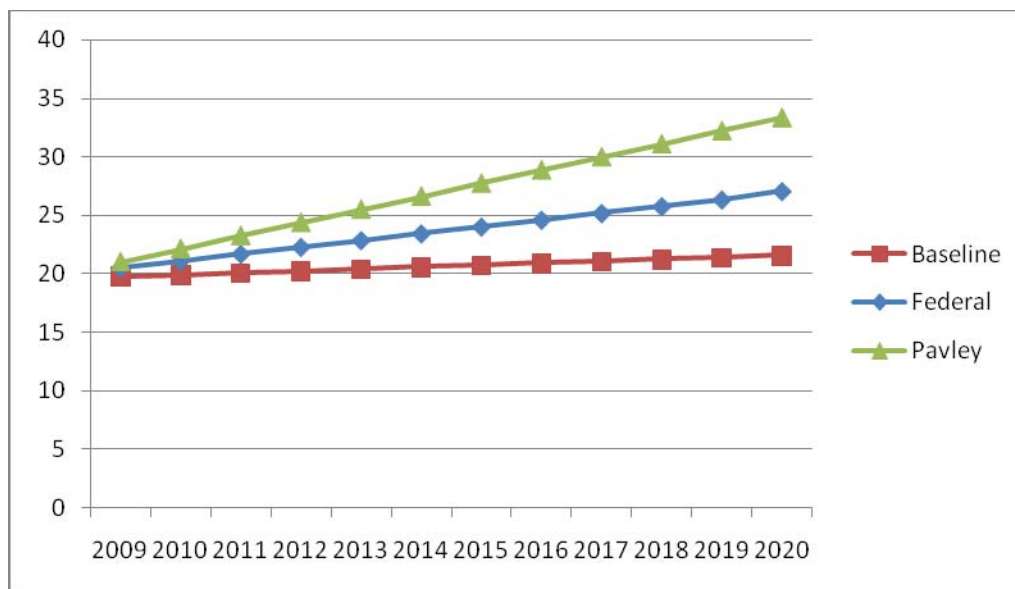


Figure 4. On-road fuel economy estimates.

The next set of calculations involves a modeling of the vehicle fleet over time. This section is based heavily on the VISION model. We use VISION model data on new vehicle sales, total vehicle fleet, and vehicle-miles-traveled (VMT) along with the VISION model specification for modeling scrappage each year to develop a vintage model where part of the vehicle fleet is retired each year. This allows for calculation of the VMT by model year for each year 2008 to 2020. Under AB 1493 and the Energy Bill, the VMT of new vehicles is adjusted by the *rebound*

<sup>39</sup> Melaina, M. (2008). "VISION-CA Model." Retrieved June, 2008, from [http://steps.ucdavis.edu/research/Thread\\_6/index\\_html](http://steps.ucdavis.edu/research/Thread_6/index_html).

<sup>40</sup> EIA (2005). Annual Energy Outlook 2005. Washington, DC, US Department of Energy.

*effect*. The rebound effect describes how higher vehicle fuel economy lowers the cost per mile of driving, thus leading consumers to drive more in aggregate. The increase in aggregate VMT offsets part of the impact of the efficiency gain on fuel use.

The size of the rebound effect is somewhat controversial. There are a variety of studies in the literature on personal vehicles (e.g., see one such review in Greening et al. (2000)<sup>41</sup>). Small and Van Dender (2005)<sup>42</sup> provide a careful analysis to CARB on the rebound effect using annual state-level data for the contiguous United States. Small and van Dender estimate the short-run elasticity of VMT with respect to fuel cost for California as  $-0.022$ , and the long-run elasticity as  $-0.113$ . They find California has a smaller rebound effect than other states due to the higher average income in California, a thought-provoking result that could use additional research. We consider these results and the most common results in the literature, which tend to fall between  $-0.10$  and  $-0.20$ , and settle upon rebound effect assumption of  $-0.10$  (often written in the literature as a “rebound effect of 10%”). We perform a sensitivity analysis on this parameter and find that it does not sway the results greatly.

Before calculating fuel used, we account for VMT driven by PHEVs, which are assumed to have a higher fuel economy than gasoline vehicles regardless of the implementation of the Energy Bill standards or AB 1493. A discussion of the PHEV methodology is described in a later section. We then use the total rebound effect adjusted VMT along with the fuel economy assumptions to calculate fuel used. The fuel gallons used are divided into gasoline gallons and ethanol gallons used based on the results of the ethanol analysis, which is also described later. Including the results of the PHEV and ethanol analysis is essential to prevent double-counting of emissions reductions. From the gasoline and ethanol savings, we then compute the carbon dioxide emission savings from the 2007 Federal Energy Bill to be 19.6 MMt CO<sub>2</sub> and the additional emission savings from AB 1493 over the 2007 Federal Energy Bill to be 13.7 MMt CO<sub>2</sub>. We use a carbon intensity of 8.92 kg CO<sub>2</sub> per gallon of gasoline and 6.69 kg CO<sub>2</sub> per gallon of ethanol (75% of the gasoline estimate).<sup>43</sup>

The next step in the analysis is to determine the cost-effectiveness of these emissions reductions. We began by surveying the literature for the best estimates of the cost of adding fuel economy improvements to new vehicles. There are several studies in the literature that provide a MAC curve. The National Research Council (2003)<sup>44</sup> report reviews this literature and develops reasonable estimates of MAC curves of fuel economy improvements for different vehicle types. More recently, Duleep (2006)<sup>45</sup> developed a separate, and more optimistic, set of estimates for Transport Canada. These estimates are used by Subin (2008)<sup>46</sup> in an analysis of measures to

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<sup>41</sup> Greening, A., D. Greene, et al. (2000). "Energy Efficiency and Consumption-the Rebound Effect-a Survey." *Energy Policy* 28: 389-401.

<sup>42</sup> Small, K. and K. Van Dender (2005). A Study to Evaluate the Effect of Reduced Greenhouse Gas Emissions on Vehicle Miles Traveled. Final Report, ARB Contract Number 02-336. Sacramento, CA, California Air Resources Board.

<sup>43</sup> Farrell, A., D. Sperling, et al. (2007). A Low-Carbon Fuel Standard for California Part 1: A Technical Analysis. Berkeley, CA, UC-Berkeley Transportation Sustainability Research Center.

<sup>44</sup> National Research Council (2003). The Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards, National Academy of Sciences.

<sup>45</sup> Duleep, K. (2006). Technologies to Reduce Greenhouse Gas Emissions from Light-Duty Vehicles. Final Report to Transport Canada, Energy and Environmental Analysis, Inc.

<sup>46</sup> Subin, Z. (2008). Greenhouse Gas Abatement Supply Curves for California's Transportation Sector, Working Paper. Berkeley, CA, UC-Berkeley Energy and Resources Group.

reduce emissions from the transportation sector, including PHEVs and ethanol measures. The Northeast States Center for a Clean Energy Future (NESCCAF) (2004)<sup>47</sup> also developed a recent set of estimates, with lower costs of improving fuel economy than much of the literature, partly by including more possible actions.

For this study, we settled on using the National Research Council (NRC) (2003) estimates. This choice was made for a variety of reasons. First, we were unable to obtain detailed information about the development of the Duleep (2006), which were the most recent estimates. Thus, it was difficult to verify the estimates. We reviewed the NESCCAF study, but passed over it for the estimates in NRC due to the more rigorous review the NRC estimates underwent. It is difficult to ascertain whether using the NESCCAF estimates would greatly improve the cost-effectiveness, but it is likely the cost-effectiveness would be improved at least somewhat.

The NRC (2003) estimates provide the basis for a marginal cost curve or MAC curve giving the cost of incremental fuel economy improvements. We take the MAC curve for each vehicle type, and then solve for the marginal cost that brings the fleet-wide harmonic weighted average fuel economy to the target levels of the 2007 Federal Energy Bill and AB 1493. Using this methodology, some vehicle types increase their fuel economy more than others. Note that this methodology also assumes that both the share of each vehicle type and the MAC curves themselves remain the same over time. To the extent that technological improvements allow for fuel economy improvements at a lower cost, this analysis overestimates the costs, reducing the cost-effectiveness.

After calculating the marginal cost for the desired reductions, we then calculate the total cost of achieving the desired reductions for each vehicle type. This provides an estimate of the total cost of achieving the emissions reductions across all vehicle types. We perform the calculation for both the Energy Bill and the additional reductions for AB 1493, allowing for estimates for the “upfront” average cost of each of the two policies. Separately, we also calculate the average gallons of gasoline used per year per vehicle, and the resulting dollar savings from reduced gasoline expenditures.

Finally, we calculate the cost-effectiveness under two different assumptions. Empirical evidence suggests that consumers often only value the first three years of fuel savings in the new car purchase decision. However, new cars have an expected lifespan of approximately 14 years, so consumers actually receive the fuel savings over all 14 years. So, we calculate the net discounted cost of achieving the fuel economy improvements assuming that consumers only value the first three years of fuel savings (as they actually act) *and* assuming consumers value the fuel savings over all 14 years of the lifespan of vehicle.

We use the discount rate of 5% and take the net present value of the dollars of fuel savings and the upfront cost of achieving the fuel savings. If consumers only value the first three years, the net present value of the 2007 Federal Energy Bill is \$1,003 and the net present value of adding AB 1493 is \$291. These positive net present values imply that the cost-effectiveness is negative for both. For the Energy Bill the cost-effectiveness over the 14 years is -\$89 and adding AB 1493 implies a cost-effectiveness of -\$35. Performing the same estimates assuming consumers value the fuel savings over all 14 years yields a net present value of the Energy Bill of

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<sup>47</sup> Northeast States Center for a Clean Energy Future (2004). Reducing Greenhouse Gas Emissions from Light-Duty Vehicles. Boston, MA.

\$4,021 and of the addition of AB 1493 of \$2,429. This implies a cost-effectiveness of -\$356 and -\$290 for the Energy Bill and adding AB 1493 respectively. Either the three year or 14 year pair of estimates could be used, although there would need to be some justification for using the latter, such as a market failure that leads consumers to undervalue fuel savings. Without a solid theory behind such a market failure, we select the former estimate to include in the AB 32 MAC curve.

#### *Discussion and caveats*

As mentioned above, there are a few caveats to keep in mind in these final results. First, there is no feedback linking shares of vehicle sales to fuel economy. We recognize that there is likely to be some feedback, since consumers may change car purchasing decisions when the amount they spend on fuel changes. Additionally, even if there is not a feedback, there may be exogenous shifts in the shares of different types of vehicles over time, which would alter the results.

### **3.3.2. Heavy duty vehicle improvements in fuel economy**

#### *Background*

Transportation accounts for 40% of California's greenhouse gas emissions, much of which involves long-haul shipments by Class 8 trucks.<sup>48</sup> Reducing the aerodynamic drag on truck trailers would increase fuel economy and save truck companies thousands of dollars per year in fuel costs. Over the lifetime of a truck, fuel savings substantially outweigh upfront expenditures on aerodynamic trailers. Thus, the resulting reductions in CO<sub>2</sub> emissions come at negative costs.

Possible reasons for the lack of investment in aerodynamic trailers to this point include the upfront costs of retrofit or new trailers, sunk costs in existing infrastructure, and until recently, moderate fuel prices. With today's fuel prices, the average payback period for an efficient trailer is about two years. Clearly, the emission savings from this measure are cost-effective by all definitions, so the primary question becomes how much potential savings exist.

#### *Emissions reductions and costs*

Based on the number of Class 8 trucks registered in California and expected growth to 2020, 0.73 MMt CO<sub>2</sub> could be avoided by using aerodynamic trailers. An additional 0.49 MMt CO<sub>2</sub> could be reduced by requiring trucks that enter California to have the efficient trailers.

The calculations to achieve these results begin with the understanding that 1.1 billion trucks were registered in California in 2003.<sup>49</sup> We assume a 2% growth rate and 10-year turnover rate and that 2.5% of the trucks are applicable for this fuel economy measure. By 2020, therefore, all applicable trucks could exhibit the aerodynamic design, amounting to 42,000 vehicles. Class 8 trucks are expected to average 90,000 miles/year and operate 1/3 on gasoline and 2/3 on distillate fuel. In addition to California-registered trucks, 28,000 out-of-state trucks will enter the California in 2020. The new trailers provide a presumed increase in fuel economy from 6.1 mpg

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<sup>48</sup> California Energy Commission. (2006). "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004." Retrieved May, 2008, from [www.arb.ca.gov/cc/inventory/doc/doc\\_index.php](http://www.arb.ca.gov/cc/inventory/doc/doc_index.php).

<sup>49</sup> US Department of Transportation Research and Innovative Technology Administration. (2008). "Bureau of Transportation Statistics." from <http://www.transtats.bts.gov>.



to 6.95 mpg. Sources and other assumptions are included in the combined spreadsheet of vehicle calculations.

This abatement quantity of 1.25 MMt is less than the 2.2 MMt projected in the CARB Early Actions Report from October 2007, which assumes that the entire nation would adopt this measure and that 11% of the CO<sub>2</sub> savings would ensue in California.<sup>50</sup> The CARB analysis estimates total miles traveled in the United States compared to our per-truck analysis. The 2007 report also admits that the 2.2 MMt is a high-end estimate.

The important characteristic of this measure's costs is that they are negative. Despite some uncertainty in the precise cost of trailer retrofits and replacements and despite unknown fuel costs, sensitivity analysis demonstrates that this measure provides net economic savings. Social benefits are even greater when considering reduced air toxins from less fuel combustion.

Estimates of costs per avoided ton of CO<sub>2</sub> could reach below -\$200. This assumes an upfront incremental cost of \$24,000 per truck, which is comparable to the value that the CARB uses and higher than most industry estimates.<sup>51</sup> The analysis takes oil prices of \$130 per barrel, a discount rate of 5%, and other assumptions listed earlier in this report and in the appendix. While this cost might seem unreasonably negative, it appropriately reflects the large fuel savings (\$40,000) divided by moderate CO<sub>2</sub> savings (175 tonnes) per truck.

#### *Discussion and future research*

Uncertain fuel prices and varying discount factors leave some uncertainty in the cost estimate for this measure, but under a range of assumptions the economic costs are always negative. These costs do not account for social benefits from reduced fuel consumption nor do they address the market barriers that prevent truck companies from investing in aerodynamic trailers now. Recent fuel price escalations and an expanding market of aerodynamic trailers will induce more adoption, but for complete market penetration, some costs for regulation or extra incentives need to be added to the pure economic estimate.

This analysis is restricted to Class 8 trucks, which define the long-haul, tractor-trailer vehicles that consume 78% of the fuel used by all heavy-duty trucks.<sup>52</sup> However, additional fuel economy measures could achieve some CO<sub>2</sub> reductions from smaller truck classes, which are not yet considered in this overall study.

### **3.3.3. Low carbon fuel standard: ethanol**

#### *Background*

The Stanford AB 32 Team estimates that emissions from the California light duty vehicle fleet can be reduced by 6.8 MMt at the cost of \$91/ton utilizing ethanol. Ethanol can displace gasoline use in two ways: 1) increasing the blend of ethanol in gasoline, 2) increasing the fleet of

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<sup>50</sup> California Air Resources Board (2007). Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California. Sacramento, CA.

<sup>51</sup>Ibid.

Van Amburg, B. (2008). Personal Communication (WestStart).

Wilson, B. (2008). Heavy Duty Truck Fuel Economy Options-Cost-effectiveness and Fuel Economy Impact, TIAX, LLC.

<sup>52</sup> Cooper, C. (2008). Heavy-Duty Fuel Economy and Emissions Improvement Project: Overview and Status Report. Boston, MA, NESCCAF.

ethanol capable vehicles in California. These steps will only reduce emissions when combined with efforts to reduce the carbon intensity of ethanol supplied to the state.

Vehicles capable of running on ethanol are on California's roads today in the form of Flex Fuel Vehicles (FFV). Flex fuel vehicles are capable of burning gasoline that is blended with up to 85% ethanol (E85) and make up approximately 4% of the California vehicle fleet.<sup>53</sup> Flex Fuel Vehicles are similar to conventional vehicles with several low cost modifications that lead to only a minor change in vehicle price, usually considered in the range of \$100-\$200.<sup>54</sup> We adopt the assumption that incorporating the flex-fuel capability in a new vehicle adds \$100 to the cost of the vehicle. Conventional vehicles can also burn ethanol; however the ethanol blend in gasoline cannot exceed 10%. This is upper limit that allows continued use of the same gasoline distribution infrastructure and gasoline engine technology.

Ethanol can be produced using various processing technologies utilizing different biomass feedstocks. Three types of feedstocks are considered viable for producing ethanol, these include: grains, sugar crops, and cellulose rich biomass. Grain based ethanol is produced from carbohydrates contained in harvested grains such as corn; grain based ethanol makes up the majority of California's (and the United States') ethanol production. Sugar based ethanol is produced in a similar manner to grain ethanol though it requires fewer chemical conversions and thus costs less to produce. Sugar based ethanol is the predominant source of ethanol in tropical regions where sugarcane is abundant; production facilities in the United States are limited. Ethanol can also be produced from cellulosic material contained in the photosynthetic and structural parts of green plants. Cellulosic ethanol production technology is still in the development stages, hence it currently has a high production cost. The Department of Energy expects these costs to decline with research and development over the years to come.

#### *Ethanol emissions*

Full fuel cycle analysis reveals the utilization of different feedstocks for ethanol production result in different GHG emissions. The GREET model was adapted by Farrell and Sperling to analyze life cycle emissions of ethanol that could be used in California.<sup>55</sup> Ethanol was classified under three types, described below, depending on their life cycle emissions, summarized in Table 9. We use these classifications of ethanol and their full fuel cycle emissions in our analysis:

1. **Average 2004 Biofuel** – Average corn based ethanol produced in the Midwest and shipped to California.
2. **Mid-GHG Biofuel** – An average of four conversion pathways that have lower emissions compared to Average 2004 Biofuel: (i) Midwest corn ethanol from a natural gas-fired dry-mill (ii) Midwest corn from NG-fired dry-mills delivering wet cake as a co-product, (iii) Midwest corn ethanol using biomass as fuel in a dry-mill, and (iv) California corn ethanol produced in a natural gas-fired dry-mill, delivering wet cake as a co-product.

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<sup>53</sup> Melaina, M. (2008). "VISION-CA Model." Retrieved June, 2008, from [http://steps.ucdavis.edu/research/Thread\\_6/index.html](http://steps.ucdavis.edu/research/Thread_6/index.html).

<sup>54</sup> Anderson, S. (2008). Emerging Markets for Biofuels, PhD Dissertation. Department of Economics. Ann Arbor, MI, University of Michigan.

Union of Concerned Scientists. (2008). "Benefits and Limitations of Flex-Fuel Vehicles." Retrieved June 25, 2008, from [http://www.ucsusa.org/clean\\_vehicles/cars\\_pickups\\_suvs/flex-fuel-vehicles.html](http://www.ucsusa.org/clean_vehicles/cars_pickups_suvs/flex-fuel-vehicles.html).

<sup>55</sup> Farrell, A., D. Sperling, et al. (2007). A Low-Carbon Fuel Standard for California Part 1: A Technical Analysis. Berkeley, CA, UC-Berkeley Transportation Sustainability Research Center.

3. **Low-GHG Biofuel** –An average of three cellulosic pathways utilizing (i) California poplar trees, (ii) California switchgrass, and (iii) Midwest prairie grass as feedstocks.

Table 9. Carbon intensity of fuels

	<b>Gasoline</b>	<b>Average 2004 Biofuel</b>	<b>Mid-GHG Biofuel</b>	<b>Low-GHG Biofuel</b>
<b>Carbon Intensity (MMtC/Quad)</b>	<b>26.90</b>	<b>21.86</b>	<b>16.55</b>	<b>3.23</b>
<b>Percent Reduction from Gasoline</b>	<b>0%</b>	<b>18%</b>	<b>38%</b>	<b>88%</b>

*Emissions reductions and costs*

To arrive at our estimates, we develop a light duty vehicle fleet analysis model building upon the methodology adopted by the California VISION model.<sup>56</sup> The model examines the use of ethanol and gasoline under the BAU Scenario and the AB 32 Scenario simultaneously. The difference in fuel consumption between the scenarios used to calculate the abatement potential. Measure cost is calculated as the difference in fuel expenditures by the fleet under both scenarios.

We take several assumptions found in the VISION-CA model to describe our 2020 BAU projection. We assume the current mix of vehicles and fuel usage is maintained with no significant changes before 2020. Gasoline continues to contain a 5.7% ethanol blend; blending accounts for nearly 90% of ethanol use in the state. Flex fuel vehicles account for 12% of new vehicle sales in 2020, however only 5% of their VMT are powered by E85. We updated the BAU scenario in the model to contain fuel economy targets set by AB 1493 (Pavley) in 2020. Our analysis of the Pavley measure shows the on-road fleet average fuel economy will be 33.4 mpg in 2020.

The AB 32 Scenario we present includes a higher ethanol blend in statewide gasoline, increased sales of FFVs, increased usage of E85 by FFVs, and increased supply from Mid-GHG and Low-GHG ethanol producers. Our assumptions are similar to those made by Farrell and Sperling in their analysis of a “Biofuel Intensive Scenario” (scenario “G5”) in their study of the LCFS.<sup>57</sup> Ethanol blended in gasoline is increased to 10% by volume. Sales shares of FFVs are increased to 35% in 2020, an assumption made by Farrell and Sperling citing press releases from US auto makers on their capability to increase production of FFVs to half of all new vehicles in 2012.<sup>58</sup> The percent of FFV VMT powered by E85 is increased to 50% requiring an increase in the number of E85 fueling stations. Finally, 20% of the biofuel supplied to California is Low-GHG ethanol while 30% is Mid-GHG ethanol.

Current ethanol production prices are estimated from the USDOE as well as spot prices for ethanol in Iowa. Production costs exclude distribution and marketing costs, taxes and subsidies.

<sup>56</sup> Melaina, M. (2008). "VISION-CA Model." Retrieved June, 2008, from [http://steps.ucdavis.edu/research/Thread\\_6/index.html](http://steps.ucdavis.edu/research/Thread_6/index.html).

<sup>57</sup> Farrell, A., D. Sperling, et al. (2007). A Low-Carbon Fuel Standard for California Part 1: A Technical Analysis. Berkeley, CA, UC-Berkeley Transportation Sustainability Research Center.

<sup>58</sup> Ibid.

The USDOE's estimate for the current production cost of cellulosic ethanol is \$2.50/gal.<sup>59</sup> We assume cellulosic ethanol is first commercialized in 2010 at this production cost. Corn ethanol spot prices in Iowa are reported by the USDA. We estimate the cost of corn ethanol production to be \$2.30/gal, the average FOB spot price from January to May 2008.<sup>60</sup> The production cost of Average 2004 ethanol and Mid-GHG ethanol are assumed to be same and follow corn ethanol production costs. Low-GHG ethanol production cost follows the estimates of cellulosic ethanol production costs. Costs are summarized in Table 10.

In some studies, ethanol production costs are projected to drop in the future. For example, McKinsey projects the cost for cellulosic ethanol in the United States declines from \$1.83/gal in 2010 to \$1.28/gal in 2030 (interpolating: \$1.55 in 2020).<sup>61</sup> The US Department of Energy targets are more optimistic with costs no higher than \$1.20/gallon by 2017.<sup>62</sup> Vattenfall projects cellulosic production costs will drop to \$1.50/gal by 2020.<sup>63</sup> Corn ethanol production costs are estimated by the USDA<sup>64</sup> to be \$1.65/gal; Vattenfall estimates approximately the same at \$1.61/gal.

However, when these studies were performed corn and oil prices were much lower than today. Ethanol production costs are tied to both corn and oil prices. Higher corn prices increase the cost of the ethanol feedstock and higher oil prices increase the production cost of grains as well as transportation costs for harvested feedstock and finished ethanol product. We therefore use our best judgment and assume that ethanol prices will be the same as gasoline prices from 2008 through 2020.

We also perform a sensitivity analysis where we modify our ethanol production cost estimates to account for today's higher oil prices. Analysis contained in the US DOE *Biomass Multi-Year Program Plan* shows the assumption that gasoline production costs make up 63% of gasoline retail prices.<sup>65</sup> Additionally cellulosic ethanol production cost in 2020 is assumed to be 34% below the production cost of gasoline. Analysis by Vattenfall assumes production costs for cellulosic ethanol will fall below that of starch (grain) based ethanol; starch ethanol will cost 7% more to produce than cellulosic ethanol. Adjusting for increased oil prices we would find that a retail price of \$4.00/gal of gasoline in 2020 translates to a gasoline production cost of \$2.52/gal. The adjusted production cost of starch and cellulose based ethanol in 2020 is \$1.78/gal and \$1.66/gal respectively (all prices \$2007).

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<sup>59</sup> US Department of Energy Office of Energy Efficiency and Renewable Energy (2007). Getting to Full-Scale Commercialization of Cellulosic Ethanol. Washington, DC, Future Fuels Conference Proceedings.

<sup>60</sup> US Department of Agriculture (2008). National Weekly Ethanol Summary, USDA Livestock and Grain Market News, June.

<sup>61</sup> McKinsey and Company (2007). Reducing U.S. Greenhouse Gas Emissions: How Much and at What Cost? US Greenhouse Gas Abatement Mapping Initiative Executive Report.

<sup>62</sup> US Department of Energy Office of the Biomass Program (2007). Biomass Multi-year Program Plan, November 2007. Washington, DC.

<sup>63</sup> Vattenfall (2007). The Landscape of Global Abatement Opportunities up to 2030: Transportation Sector Deep-Dive.

<sup>64</sup> US Department of Agriculture (2007). The New World of Biofuels: Implications for Agriculture and Energy. EIA Energy Outlook, Modeling, and Data Conference, March 2007.

<sup>65</sup> US Department of Energy Office of the Biomass Program (2007). Biomass Multi-year Program Plan, November 2007. Washington, DC.

However, our best estimate of future starch-based ethanol price is that it will track future gasoline prices exactly, since the cost of corn rises with the cost of gasoline. The costs we settle upon are summarized in Table 10 below.

Table 10. Fuel production costs in 2007 and 2020

<b>Production Cost (\$2007/gal)</b>	<b>Gasoline</b>	<b>Average 2004 Biofuel</b>	<b>Mid-GHG Biofuel</b>	<b>Low-GHG Biofuel</b>
<b>2007</b>	<b>\$2.52</b>	<b>\$2.30</b>	<b>\$2.30</b>	<b>\$2.50</b>
<b>2020</b>	<b>\$2.52</b>	<b>\$2.52</b>	<b>\$2.52</b>	<b>\$1.66</b>

Emissions from the California light duty vehicle fleet can be reduced by 6.8 MMt CO<sub>2</sub> at the cost of \$91/ton. Achieving these reductions would require ethanol supplied to California to increase to 1.6 Bgal from business the usual consumption of 0.48 Bgal. Mitigation costs are based on fuel production costs only, taxes and subsidies are not considered

*Discussions and future research*

There is much debate about the full fuel cycle emissions of both cellulosic and starch based ethanol. The GREET model was used to analyze ethanol emissions; however, its shortcomings in the handling of land use changes are apparent.<sup>66</sup> As more work continues to perfect land-use effects in the GREET model, life cycle emission estimates could change. Critics of the GREET argue it is generous to biofuels and that full fuel cycle emissions are actually higher than what the model concludes. Increasing the carbon intensity of biofuels would decrease the abatement potential from ethanol while increasing the cost per ton of abatement.

The analysis of the measure was performed without accounting for gasoline tax and any potential tax or subsidy on ethanol. It is uncertain to our team if subsidies on ethanol will continue until 2020 or if taxes similar to those on gasoline will take effect by then.

**3.3.4. Low carbon fuels standard: biodiesel**

*Background*

Biodiesel fuel for diesel engines is produced from vegetable oil or animal fat through chemical processing; it offers lower full fuel cycle emissions than conventional diesel. Low blends of biodiesel (2-20%) in diesel can be tolerated by most diesel engines; higher blending levels may reduce performance during cold weather. Current supplies of biodiesel are limited in California; achieving significant GHG abatement would require substantial market expansion.<sup>67</sup>

*Emissions reductions and costs*

<sup>66</sup> US Environmental Protection Agency Office of Transportation and Air Quality (2007). Regulatory Impact Analysis: Renewable Fuel Standard Program. Washington, DC.

<sup>67</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

The Stanford AB 32 team is building on the analysis performed by the CAT Macroeconomic Analysis to quantify the cost effectiveness of the biodiesel measure. The CAT Analysis estimates that biodiesel could displace 4% of diesel fuel by 2020 providing a GHG abatement of 0.8 Mmt. While the CAT Analysis did not estimate a cost for the measure, we estimate the cost will be \$22.80/ton.

Due to limited information regarding biodiesel costs and the low potential for abatement from this measure, the Stanford AB 32 team calculated a simple placeholder for the cost of this measure. We estimate the retail cost of a 20% biodiesel blend (B20) to be 1.3% lower than conventional diesel per gallon. This figure originates from the ratio of B20 retail price to diesel retail price averaged over six data points from October 2006 to April 2008 and is assumed to stay constant until 2020.<sup>68</sup> Though B20 costs less per gallon, it has a lower energy content decreasing fuel economy. Emissions from B20 are estimated from the GREET model to be 10.1% lower than diesel per gallon. We estimate the cost effectiveness of this measure as the cost effectiveness of displacing conventional diesel with B20 based on retail prices.

#### *Discussion and future research*

Biodiesel production costs and retail prices remain uncertain, there is limited literature documenting costs and projections for the near future. Biodiesel production is limited in California and expanding the industry may require significant capital costs. Further research into production and capital costs could provide a more accurate estimate of the cost effectiveness of this measure. Abatement potential should also be updated to include the effects of the SmartWay program on diesel consumption in California.

### **3.3.5. Light duty plug-in hybrids**

#### *Background*

Plug-in Hybrid Electric Vehicles (PHEVs) are hybrid electric vehicles with a large battery that can be charged from an electrical outlet. The reduction in emissions is mainly due to a lower amount of greenhouse gas emissions from the use of electricity in a car than gasoline. The net impact on greenhouse gas emissions therefore depends on the regional electricity generation base, which in some areas is heavily based on fossil fuels. The extent to which PHEVs can be deployed also depends on regional factors such as spare capacity, load shape, and grid congestion.

#### *Emissions reductions and costs*

PHEV reductions in emissions were taken above emissions reductions that could be accomplished by changing fuel efficiency standards. A typical PHEV with 40-mile range was compared to a typical vehicle with the mandated fleet average fuel economy set out in AB 1493 (Pavley). The vehicles were assumed to drive 12,000 miles a year, or roughly 40 miles per day.

According to a 2006 PNNL study on the impact of PHEVs, a PHEV will emit 39% less greenhouse gas emissions over the course of its lifetime than a typical 35 mpg small car. This emissions benefit changes over time as both PHEVs and conventional cars become more fuel efficient, and as the composition of the electric power grid changes. The economics of these cars

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<sup>68</sup> US Department of Energy (2008). Clean Cities Alternative Fuels Price Report, Oct 2006, Mar 2006, Jul 2007, Oct 2007, Jan 2008, Apr 2008.

also changes as prices of electricity and gasoline change, as well as the base cost of each car. Our analysis assumes a 2% gas price escalation and a 2% electricity price escalation per year, with a discount rate of 5%. The base prices used for gas and electricity were \$4/ gallon and \$0.14/ kWh, respectively, with the latter coming from E3 model results.

The economics of each vehicle are viewed under the lens of a learning-by-doing analysis, which incorporates the long term societal benefit of reduced technology cost into the overall benefit calculation for a purchase today. With these impacts included, the cost-effectiveness is roughly \$4 per MMt CO<sub>2</sub>e, with a reduction potential of 6.0 MMt CO<sub>2</sub>e in 2020. These estimates are roughly consistent with estimates given by NREL and others in the literature.<sup>69</sup>

### **3.3.6. Medium/heavy truck hybridization**

#### *Background*

Hybrid technology is becoming more widely applicable to local delivery trucks, short-haul large trucks, and even long-haul Class 8 trucks for improving fuel economy and thus reducing CO<sub>2</sub> emissions. The dual gasoline-electric engine saves significant amounts of fuel in stop-and-go movement through regenerative braking. As such, it has traditionally been favored for parcel delivery trucks. Recent research has also found sufficient fuel savings from Class 8 trucks mounting and descending hills and continuing electric necessities such as refrigeration without idling. The analysis in this section focuses on these two categories of trucks: parcel (Class 3 to 5) and Class 8. Research on other hybrid potential including refuse collection trucks is extremely limited, but could add to the CO<sub>2</sub> saving potential estimated here.

#### *Emissions reductions and costs*

The estimate for potential CO<sub>2</sub> emission savings from hybrid parcel trucks comes directly from the CARB Early Action Measures Report, which assumes that all new Class 3 to 5 trucks sold in California beginning in 2015 use hybrid technology.<sup>70</sup> This amounts to 0.5 MMt CO<sub>2</sub> as calculated from the CARB's vehicle miles traveled and fuel economy improvement assumptions (see CARB (2007)). It also equals approximately 30% of the potential if all Class 3 to 5 trucks in 2020 were hybrids instead of only those built after in 2015 or later.

In addition to Class 3 to 5 trucks, Class 8 trucks promise untapped CO<sub>2</sub> reduction potential via hybrid technology. This potential exhibits minimal overlap with other fuel economy measures such as aerodynamic trailers. The CO<sub>2</sub> savings from this aspect of the measure are also estimated at 0.5 MMt. This hybrid potential comes from conserving fuel on hills and on electric requirements of the truck. To calculate this potential, we assumed a growing percentage of Class 8 trucks will have hybrid technology in each year beginning in 2012. By 2020, 20% of new trucks would be hybrids. This amounts to 50,000 new hybrids. Each Class 8 hybrid saves 11 tons of CO<sub>2</sub> per year, assuming 80,000 miles per truck per year and improved fuel economy from 5.2 mpg to 5.6 mpg. These conservative numbers reflect the small overlap between fuel economy measures for Class 8 trucks.

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<sup>69</sup> Kintner-Meyer, M. (2006). Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional US Power Grids. Hanford, WA, Pacific Northwest National Laboratory.

<sup>70</sup> California Air Resources Board (2007). Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California. Sacramento, CA.

Hybrid truck engines are a relatively immature technology with highly uncertain costs. Most estimates for the incremental costs of a hybrid parcel truck range from \$30,000 down to \$10,000 if production units exceed 10,000 trucks. Taking a mid estimate of \$20,000, diesel fuel prices the same as our gasoline price assumptions, and fuel economy improvements from 7.2 mpg to 9.7 mpg, the cost per ton of CO<sub>2</sub> reduced equals \$62. This value is highly sensitive to the upfront cost assumptions. For example, a \$10,000 incremental truck cost changes the cost per ton of CO<sub>2</sub> to -\$82.

Costs for Class 8 hybrids are even less known. The technology currently adds between \$60,000 and \$80,000 to the cost of a truck, but those costs are expected to drop to \$40,000 within 5-10 years and down to \$20,000 at production volumes above 10,000 trucks. Because these hybrid engines can be produced in large quantities and then disseminated to different truck manufacturers, the 10,000-production volume is achievable within this time frame.<sup>71</sup>

Assuming incremental costs of \$30,000 and the fuel economy estimates described above, costs for emissions reductions from Class 8 hybrid trucks are \$205 per ton CO<sub>2</sub>. The CO<sub>2</sub> costs associated with both types of hybrids are also highly sensitive to fuel prices, with a drop in crude oil prices increasing costs per ton of CO<sub>2</sub> by \$36.

#### *Discussion and future research*

These sensitivities and the uncertainties associated with hybrid technology and fuel costs generate considerable uncertainty in hybrid emission reduction cost estimates. Learning-by-doing was generally worked into the model by using mid-case cost values instead of current industry costs; however, the analysis should be recalibrated as truck hybrid technology develops and cost trends become more explicit.

Social costs associated with external benefits from reduced fuel combustion are not factored into this cost model. Nor are the social costs of overcoming market barriers. The large up-front investment required for hybrid trucks and concerns over immature technology could demand additional government spending on incentives or regulations than the pure economic costs in this report suggest.

Finally, while this analysis differentiates between two types of hybrid truck applications, it assumes the same characteristics for all Class 3 to 5 trucks and all Class 8 trucks. Because fuel savings depend on specific truck use, ranging from inner city refuse collection to rural parcel delivery, a more detailed analysis of different hybrid truck applications would provide more precise categories of emission reduction quantities and costs.

### **3.3.7. Shore electrification**

#### *Background*

Shore electrification was selected as an early action item by the California Air Resources Board. When ocean going vessels dock, onboard auxiliary engines provide the ship's electrical needs powering lights, electronics, pumps, cranes, and other equipment. The shore electrification measure will require a majority of ships visiting California ports to plug into shore-side electrical outlets and to shut down auxiliary engines. Emissions will result from with the generation of grid electricity; however, these emissions are small compared to those from the auxiliary

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<sup>71</sup> Van Amburg, B. (2008). Personal Communication (WestStart).



engines. Additional benefits include improved local air quality. Expanding the use of shore electrification requires vessel modifications and shore-side infrastructure each having high costs.

#### *Emissions reductions and costs*

We use the analysis performed in the 2006 CAT Macroeconomic Analysis to quantify the cost effectiveness of the shore electrification measure. The analysis targets 80% utilization of shore electrification by visiting ships in 2020 resulting in an abatement of 0.55 MMt CO<sub>2</sub>e. The measure will have a total cost of \$150 million and save \$119 million resulting in a net financial cost of \$56/ton.

The true benefit of this measure is not reflected in financial cost above as the value of avoided adverse health impacts is not included. Shore electrification will reduce the levels of criteria and toxic air pollutants in the area surrounding ports improving the health of locals. Including the social benefit of this improved health will allow the measure to appear more cost effective. The CAT Analysis attempts to quantify this by establishing a monetary value of reducing emissions of criteria pollutants. These values are: \$12,500/ton for reactive organic gases (ROGs);

\$20,800/ton for nitrogen oxides (NO<sub>x</sub>); and \$20,000/ton for particulate matter (PM<sub>10</sub>).<sup>72</sup> Accounting for value of criteria pollutants in addition financial costs and benefits, the measure would have a social cost of -\$407/ton.

### **3.3.8. Low rolling resistance replacement tires**

#### *Background*

Low rolling resistance (RR) replacement tires offer the ability to increase fuel economy of the average vehicle. Low rolling resistance tires are currently used by vehicle manufacturers to enable them to meet federal fuel economy standards.<sup>73</sup> However, replacement tires often have higher rolling resistance than their OEM counterparts, reducing vehicle fuel economy. Through this measure the CEC is expected to require mandatory reporting of rolling resistance by tire manufacturers, development of a rolling resistance rating system, and a consumer information program.<sup>74</sup> Furthermore, placing a minimum efficiency standard on replacement tires will ensure reductions.

The CAT Macroeconomic Report calculates an abatement potential of 0.33 MMt CO<sub>2</sub>e at a cost of -\$261/tonne. Our updated analysis however, shows abatement potential of 1.34 MMt at a cost of -\$264/tonne. The large difference in our resulting costs can partly be attributed to the fact that the CAT Analysis only considered the costs and benefits in the year 2020. However, our analysis sums all costs and benefits for each year from 2008-2020 to quantify the net measure cost.

#### *Emissions reductions and costs*

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<sup>72</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

<sup>73</sup> Tonachel, L. (2007). Fuel-Efficient Replacement Tires. New York, NY, Natural Resources Defense Council.

<sup>74</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

Our analysis draws from a 2006 report by the National Research Council on fuel efficient tires.<sup>75</sup> The NRC finds that decreasing rolling resistance by 10% is technically and economically feasible and will increase the average vehicle's fuel economy by 2%. These tires are expected to cost only \$2 more than conventional tires. Additionally, the NRC reports that 75-80% of vehicles on road use replacement tires and these vehicles replace tires every 4 years.

The use of low RR tires acts to increase on road fleet average fuel economy. We assume fuel economy follows the standards set by AB 1493 (Pavley). In our analysis, market penetration of low RR tires begins in 2010 and reaches its maximum potential in 2013. Our analysis deviates from the CAT Macroeconomic Analysis as we assume a higher market penetration. The CAT Analysis only assumes 15% utilization in 2020, however we assume nearly full penetration (75%) reflecting a minimum efficiency standard as required by AB 844 (2003).

Our analysis shows this measure would reduce gasoline consumption by 150 million gallons in 2020 reducing emissions by 1.34 MMt. Additional tire costs borne by consumers as well as administrative costs to create a rolling resistance reporting system would be outweighed by the fuel savings. The net costs of the measure (in present day value) in 2020 is estimated to be -\$354 million. We use this point estimate to calculate the cost per volume of emission reduction: -\$264/tonne.

The relatively large magnitude of this figure can be attributed to the fact that low RR tires cost marginally more than conventional tires yet offer substantial fuel savings without compromising performance. Consumers currently have no way of assessing the rolling resistance of replacement tires and the subsequent effects on their fuel economy.<sup>76</sup> Since consumers lack the information to make cost-effective choices about their tires, substantial cost savings are possible by this measure as this information barrier is breached.

#### *Discussion and future research*

There is some uncertainty in the reliability of low rolling resistance tires. Low RR tires may wear faster than conventional tires requiring consumers to change them more often than the current interval of four years.<sup>77</sup> This will result in higher costs to consumers as well as a higher volume of scrap tires to manage in California's waste stream. Further research is needed determine if indeed, the wear-life of low RR tires is shorter than that of conventional tires.

### **3.3.9. Diesel anti-idling**

#### *Background*

In July 2004, CARB adopted a measure to limit diesel-fueled commercial motor vehicle idling. Reducing and eliminating idling by diesel fueled vehicles will reduce tail pipe CO<sub>2</sub> emissions as well as NO<sub>x</sub> and PM offering the additional benefit of improved local air quality. The measure specifically limited commercial heavy-duty diesel fueled vehicle idling to a maximum of 5 minutes. The regulation was recently updated to remove exceptions for vehicles with sleeper berths and enforcement began in 2008 applying to all trucks registered in California as well as out-of state trucks traveling within the state.

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<sup>75</sup> National Research Council (2006). Tires and Passenger Vehicle Fuel Economy. Washington, DC, National Academy of Sciences.

<sup>76</sup> Ibid.

<sup>77</sup> Ibid.

### *Emissions reductions and costs*

The 2006 CAT Macroeconomic Analysis<sup>78</sup> Report analyzed this measure and concluded the measure would reduce emissions by 1.46 MMT in 2020 at a measure cost of -\$188/ton. The Stanford AB 32 team has also analyzed the measure, our results show the cost effectiveness of the measure has increased to -\$336/ton as the price of diesel have risen since the CAT Analysis. Costs and benefits do not include those related to improvements in local air quality.

Our analysis draws heavily from the CAT Macroeconomic Analysis. First, we directly use the CAT abatement potential, 1.46 MMT in 2020. Our team focused its efforts on updating the costs and benefits of the measure as diesel prices have significantly increased since the CAT Analysis.

The engines of diesel fueled vehicles are often left idling while the truck is parked to provide auxiliary power or maintain cab comfort. CARB estimates that the typical truck engine is left to idle 2,100 hours per year consuming 1 gallon of diesel per hour. Auxiliary Power Units (APUs) can be installed in trucks to provide the necessary power and cab comfort needed as an alternative to idling engines. We follow CARB's assumptions that these units cost \$8,500 each and consume 0.2 gallons per hour during operation. APU's will save 1,680 gallons of diesel reducing emissions by 16.9 tons per year per truck. The savings from reduced fuel consumption considerably outweigh the costs of an APU.

One major difference in our study is that we use a different price of diesel fuel. The CAT Analysis assumed a diesel price of \$2.14/gal in 2007 rising to \$2.20/gal in 2020 (all prices in \$2006). Our analysis assumes diesel costs \$4.00/gal in 2008 and rises 3% per year until 2020. At a 5% discount rate the real price of diesel actually declines over the period.

We calculate the cost effectiveness of the measure by analyzing the finances of retrofitting one commercial diesel fueled vehicle with an APU and determining the abatement potential from the retrofit. Using the CAT Analysis' assumptions about diesel fuel prices, our model calculates a cost effectiveness of -\$191/ton, compared to the report's figure of -\$188/ton. Updating our model for high diesel prices shows the measure is much more cost effective at -\$336/ton.

### *Discussion and future research*

While diesel anti-idling measures clearly seem cost effective, the estimate of its potential GHG abatement should be updated. The CAT Macroeconomic Analysis assumes a diesel emissions factor of 10.05 kgCO<sub>2</sub>e/gal. While this is suitable for the tailpipe emissions resulting from diesel combustion, it does not account for emissions occurring in the extraction and refining of oil to produce diesel. An emissions factor that more accurately reflects the full fuel cycle of diesel will increase the potential abatement of this measure and should be examined.

The true benefit of this measure is not reflected in the measure cost as the value of avoided adverse health impacts is not included. The CAT Analysis attempts to quantify this by accounting for value of criteria pollutants resulting in a social cost of -\$486/ton. Accounting for criteria pollutants in our analysis will result in an even lower cost, though it is not calculated in this report.

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<sup>78</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

### 3.4. Electricity generation

A significant percentage of the emissions reductions may come from the electricity sector. We analyze electricity generation primarily by using results from Energy and Environmental Economics, Inc (E3) for investor-owned utilities. We perform our own analysis for the California Solar Initiative (CSI), a large program to promote solar PV in California.

Table 11. Summary estimates for electricity generation.

Measure	Emission Reduction (MMTCO <sub>2</sub> e)	Costs (\$/MTCO <sub>2</sub> e)
CHP Residential and Commercial (price incentives and PTC)	2.33	\$30
CHP Residential and Commercial (aggressive growth)	12.84	\$6
Industrial CHP (price incentives and PTC)	1.30	\$30
Industrial CHP (aggressive growth)	7.13	\$6
Solar PV	0.81	-\$89
Wind	9.7	\$105
Biomass	0.7	\$190
Solar Thermal	20.7	\$124
Biogas	0.9	\$51
Geothermal power	2.83	\$94
Small hydro	0.1	\$92
IGCC Coal with CCS	6.5	\$255

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### 3.4.1. Combined heat and power (CHP)

#### *Background*

Combined heat and power (CHP) operations make use of waste heat from power generating combustion processes to provide additional energy services such as heating or cooling. Utilizing this waste heat displaces energy use at the point of consumption, resulting in large savings in fuel upstream. CHP can be applied to a variety of processes, industrial, commercial, and residential. CHP installations tend to perform well when they are run continuously, and serve operations that require large amounts of heat. The nature of heat distribution requires the end user's load to be located close to the heat generating facility. This, along with natural gas distribution infrastructure, limits the technical potential of CHP deployments. Recent developments of natural gas utilizing fuel cells and micro-turbines have greatly expanded the potential for distributed CHP, which allows for smaller scale applications at the commercial and residential heating level.

California is the current leader in CHP among the states, with 9.1 GW of total capacity in 2005. Oil recovery is the single largest use of CHP, followed by commercial and institutional uses, food processing, and refining. It is estimated that an additional technical potential of 24.3 GW exists in California, but that only about 8.1% (1.97 GW) of this will be added under base case scenarios between 2005 and 2020.<sup>79</sup> Assessments of the California CHP market suggest that with some policy and market changes, that between 2.5 GW to 7 GW of CHP could be achieved instead. These changes range from increase exports to providing a production tax credit or imposing a carbon tax.

#### *Emissions reductions and costs*

For the estimates of the potential for emissions reductions and cost associated to CHP, two scenarios from Darrow et al. (2005) are used:

1. increased incentives; and
2. high impact scenario.

These two scenarios are compared to the a base case over the period from 2005 – 2020. These two scenarios are not overlapping, they can both be implemented concurrently. We then consider each of them as a specific measure for the purpose of building of our MAC curve. however they are separated because of the price differences.

The *increased incentives* scenario consider to two types of financial incentives:

1. Extension of the SGIP (Self Generation Incentive Program), requiring payments of roughly \$600,000 / MW installed for the first 5 MW of projects less than 20 MW, raising the cost of the SGIP program from \$402 million to \$921 million, a total cost of \$519 million over the 15 year period.
2. Production tax credit extension of \$0.01 / kWh, or \$10 / MWh, at a total cost of \$994 million.

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<sup>79</sup> Darrow, K., B. Hedman, et al. (2005). The Role of Distributed Generation in Power Quality and Reliability, Energy and Environmental Analysis, Inc.

The total cost of increased incentives was \$1.513 billion, resulting in an increase of capacity by 0.946 GW, at a cost to the state of \$1.6 billion / GW installed. This results in a CO<sub>2</sub> reduction of 3.63 MMt CO<sub>2</sub>/year, or 54.4 MMt CO<sub>2</sub> for the 15 year period. This results in a carbon cost of \$29.2 per tonne CO<sub>2</sub> in 2006 dollars. This would be composed of 2.33 MMt CO<sub>2</sub> in the commercial and institutional sector, and 1.30 MMt CO<sub>2</sub> in the industrial sector.

The *high impact* scenario consists to the following set of measures:

1. A transmission and distribution (T&D) benefit payment of \$40/KW-year, for systems greater than 5MW and less than 20 MW that export power, at a total cost of roughly \$132 million for the 15 year period.
2. A direct CO<sub>2</sub> reduction payment of \$8 / ton of CO<sub>2</sub>, resulting in total payments of \$160 million for the 15 year period.
3. Streamlining of the approval process by improving awareness, education, training and better availability of credit or third party financing.
4. An increase in funding for R&D, through the SGIP program, resulting in a cost increase from \$402 million to \$1.9 billion, or \$1.498 billion.

The high impact case resulted in an increase in 5.374 GW over the base case, at a cost to the state of \$1.79 billion, or \$333 million/GW. This results in a CO<sub>2</sub> reduction of about 19.97 MMT CO<sub>2</sub>, at a cost of \$6.29 per tonne CO<sub>2</sub> in 2006 \$. This would be composed of 12.84 MMt CO<sub>2</sub> in the commercial and institutional sector, and 7.13 MMt CO<sub>2</sub> in the industrial sector.

### **3.4.2. Residential solar photovoltaics (California Solar Initiative)**

#### *Background*

California is well-situated to take advantage of solar photovoltaic (PV) technology with ample sunlight and burgeoning solar industry due to solar PV subsidies dating back over ten years. California has built on this history through the California Solar Initiative, which evolved from Governor Schwarzenegger's Million Solar Homes Initiative. The CSI was promulgated by a California Public Utilities Commission (CPUC) rulemaking on January 12, 2006, as one of the largest programs to promote solar photovoltaic technology in the world.

The CSI provides 11 years of subsidies for solar PV. The subsidies decline over time as the cost of PV installations declines, beginning at \$2.50/Watt in 2006. The focus of the CSI is on residential and commercial installations, with larger solar central generation covered under different programs. AB 32 uses the CSI as one of the centerpiece programs to promote renewable energy and meet the 2020 emissions limit. Under the CSI, any PV system under 5 MW is eligible for the subsidy, although incentives are paid for only the first MW of capacity installed, thus differentiating the CSI from any program to promote installation of central generation solar (e.g., solar thermal).

#### *Emissions reductions and costs*

To analyze the emissions reductions and costs, the Stanford AB 32 team draws on the numerical model developed for the journal article "Learning-by-doing and Optimal Solar Policy

in California.<sup>80</sup> This article models CSI and the optimal solar policy in California under different assumptions of future parameters. The model is based on the following key characteristics:

- Consumer choice – purchases of solar systems depend on both the net present value (NPV) of the benefits to the consumer and a diffusion process. Subsidies influence the NPV.
- Learning-by-doing – costs of supply depend on the cumulative past production and installations. This assumption will be varied in order to test its implications.
- Environmental externalities – there are externalities associated with the electricity production for which solar substitutes.

The baseline assumptions used in the model are given below in Table 12.

Table 12. Relevant parameter values used in AB 32 study	
Parameter Description	Value
Environmental externality benefit per installed Watt	\$0.015 per year
Progress ratio for modules	0.9
Progress ratio for balance of system	0.9
Long-term global solar growth rate	10%
Maximum yearly number of installations (retrofit)	200,000
Maximum yearly number of installations (new construct.)	75,000

Many of these parameters and their values only make sense in the context of the model equations. For further details of the model structure, including the model equations and the choice of parameterization, we refer the interested reader to the published journal article.

For carbon dioxide emissions reductions, this analysis uses the journal article results directly, which suggest that under the baseline parameters, just over 942,000 DC kW of residential solar PV are installed by 2020 due to the CSI. This implies that 0.40 MMT CO<sub>2</sub> are reduced in 2020 due to the residential solar PV component of the CSI.<sup>81</sup>

Of course, there will be additional emissions reductions from non-residential installations. As of September 2007, non-residential installations accounted for nearly 88% of the MW installed using the CSI incentives.<sup>82</sup> However, there are fewer potential commercial and government sites than residential sites, so with widespread solar adoption of solar technology, it is not likely that this ratio of residential to non-residential sites will continue. A more reasonable

<sup>80</sup> van Benthem, A., K. Gillingham, et al. (2008). "Learning-by-Doing and Optimal Solar Policy in California." *The Energy Journal* 29(3): 131-151.

<sup>81</sup> Using the conversion factors of 1 installed DC Watt = 1.3 kWh/year (Barry Cinnamon, Personal Communication, 2006), and 3.3x10<sup>-10</sup> MMT CO<sub>2</sub> per kWh/year (E3 baseline scenario for 2020).

<sup>82</sup> California Public Utilities Commission. (2007). "California Solar Initiative: CPUC Staff Progress Report." Retrieved August 1, 2008, from [ftp://ftp.cpuc.ca.gov/puc/energy/solar/california\\_solar\\_initiative\\_staff\\_progress\\_report\\_september\\_2007.pdf](ftp://ftp.cpuc.ca.gov/puc/energy/solar/california_solar_initiative_staff_progress_report_september_2007.pdf).

assumption is that half of the solar PV capacity installed in 2020 will be residential. Using this assumption, we find that .81 MMt CO<sub>2</sub> are reduced in 2020 from all solar PV installations due to the CSI.

To calculate the cost-effectiveness of the CSI, this study again relies on the results from van Benthem et al. (2008). For this analysis, the social costs and benefits (excluding the reductions in carbon) are broken down into the **net present value** that consumers see when they install a kW of solar PV (in 2007 and before incentives), and the present discounted value of the learning-by-doing benefits that accrue in the future from the installation of one additional kW in 2007. The learning-by-doing benefits stem from the idea that the installation of an additional kW of solar PV by one firm lowers to cost of all future installations for all firms. This is a classic case of an appropriability market failure, where there is a spillover of knowledge from one firm to other firms leading to benefits that cannot be fully appropriated by the single firm. There is evidence to suggest that solar PV exhibits learning-by-doing, as is discussed in van Benthem et al. (2008).

To calculate the value of the learning-by-doing benefit, we add one more kW in solar PV in 2007 and examine the cost of installations with and without this extra kW from 2007 to 2060. The discounted sum of the decrease in costs is the “learning-by-doing benefit.” The sum of the net present value that the consumer receives (-\$1,275) and the learning-by-doing benefit (\$2,416) gives the net social cost of a kW installed (\$1,140). This value is then converted to the social cost per kWh and divided by 30 to account for the fact that the costs can be amortized over the 30 year lifespan of a typical solar PV system. This yields a cost estimate of \$88.62 per tonne of CO<sub>2</sub>. We use this cost estimate for both the residential and non-residential emission savings, for lack of a better estimate.

### **3.4.3. Renewable energy measures (E3 model)**

#### *Background*

Greenhouse gas reduction measures in the power sector have been modeled extensively at the request of the California Air Resource Board. ICF International and Energy and Environmental Economics, Inc. (E3) have both developed detailed models for this sector. The ICF model demonstrates the impact of AB 32 on the electricity sector at a high level by analyzing the electricity market to determine the price of electricity under AB 32. The E3 calculator is an excel-based model that uses a transmission loading model to determine an integrated cost for renewable sources. The E3 model is one of the more comprehensive and transparent efforts that we are aware of, created specifically to understand GHG reduction potential in the power sector. Consequently we base many of the results in this section on model outputs from the E3 calculator.

The E3 calculator estimates the greenhouse gas emissions of the California electricity sector in the year 2020, and the associated utility-sector costs and average rate impacts in 2020. Impacts are estimated for the state, as well as eight California groupings of utilities and retail providers. These include both investor-owned utilities and municipal utilities. The purpose of the tool is to allow the analyst to select a user-defined portfolio of resources and policy choices, and to estimate the resulting emissions, costs and rate. The calculator is publicly available therefore it is possible to change assumptions as new information becomes available while the AB 32 rule making process continues. The calculator can be found at [www.ethree.com/GHG/GHG%20Calculator%20v2b.zip](http://www.ethree.com/GHG/GHG%20Calculator%20v2b.zip). E3 developed a first draft of their



report and then made changes to the model in May. Our results use the updated Stage 2 calculator from the May revision. The following two sections describe the two stages of model development.

### *Stage 1: GHG Model*

In their first modeling effort, the E3 calculator developed a reference model of the California electricity and natural gas sectors and then made the model meet a 2020 load-based cap constraint on the electricity and natural gas sector. The GHG calculator allowed users to select various demand or supply side options to meet the GHG constraint.<sup>83</sup> The calculator provided electricity and natural gas sector cost and rate impacts of reaching the 2020 goals using various demand and supply resources. The calculator also produced the marginal cost of greenhouse gas emissions reductions in the resource mix scenarios that users created.

### *Stage 2: GHG Model*

E3 explains in their documentation that the Stage 2 model was changed to “reflect the CEC/CPUC recommendations to CARB on greenhouse gas regulatory strategies.” The Stage 2 model will allow calculator users to select the market-clearing price in \$/tonne of CO<sub>2</sub>. Users are also able to choose between auction and allocation rules for the CO<sub>2</sub> market related to the electricity sector.

The costs and/or revenues from emission allowances or offsets will initially be passed to the energy generators the prices will be passed down to LSEs and then to consumers, which is reflected in the rate calculation for LSEs. E3 largely kept the resource selection functions of the Stage 1 model in the Stage 2 model. In an important addition, the Stage 2 model shows the cost of loading renewable energy sources and increasing energy efficiency savings.

### *Model assumptions for the GHG MAC curve*

Using the Stage 2 Model, we built a scenario that would show the potential for renewable sources by seeing how much renewable energy is developed in a scenario where carbon is priced at \$160/tonne (2008 dollars).<sup>84</sup>

The key user inputs include supply and demand side resources (for example energy efficiency, solar PV, demand response, combined heat and power and renewable and conventional energy generation) and CO<sub>2</sub> market assumptions which allows the user to select key parameters in a multi-sector cap and trade California carbon market (such as the market clearing price, the percentage of administration auctioned permits, offsets, emission intensity of electricity imports, and treatment of out-of-state contracts).

The decision to leave assumptions at BAU and set the market clearing price to \$160/ton was in order to see the full potential of renewable energy. Not all of this potential may be realized if depending on the other carbon market assumptions used. However, the MAC curve we have

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<sup>83</sup> E3 noted that “the Stage 1 modeling default assumption was that the ‘target’ emissions level for the electricity and natural gas sectors was equal to the 1990 sectors’ emissions from the preliminary CARB GHG emissions inventory, as of August 22, 2007. Subsequently, CARB revised the GHG inventory on November 19<sup>th</sup>, 2007, which resulted in an adjusted 1990 emissions level for the electricity and natural gas sectors.”

<sup>84</sup> The \$160/tonne carbon price scenario in the E3 model is expressed in terms of 2008 dollars. Since the scenario is referred to using this figure in the E3 model, we retain the figure of \$160 in future references to this scenario. The equivalent price in 2006 dollars is about \$147/tonne.

developed shows the technical potential and additional scenario modeling can address policy impacts. E3’s scenario analysis showed the importance of the market clearing cost for renewable adoption. Figure 5 shows the impact of market clearing cost on renewable generation and carbon reduction. At \$160/tonne over 40% renewables are added to California’s electricity mix. Note that even when carbon is not priced, renewables still enter at the base level of 20% mandated by current policy and embedded in the reference scenario. Thus the effect of increasing the carbon price is to load renewables over and above the RPS baseline – incremental costs also refer to this additional loading.

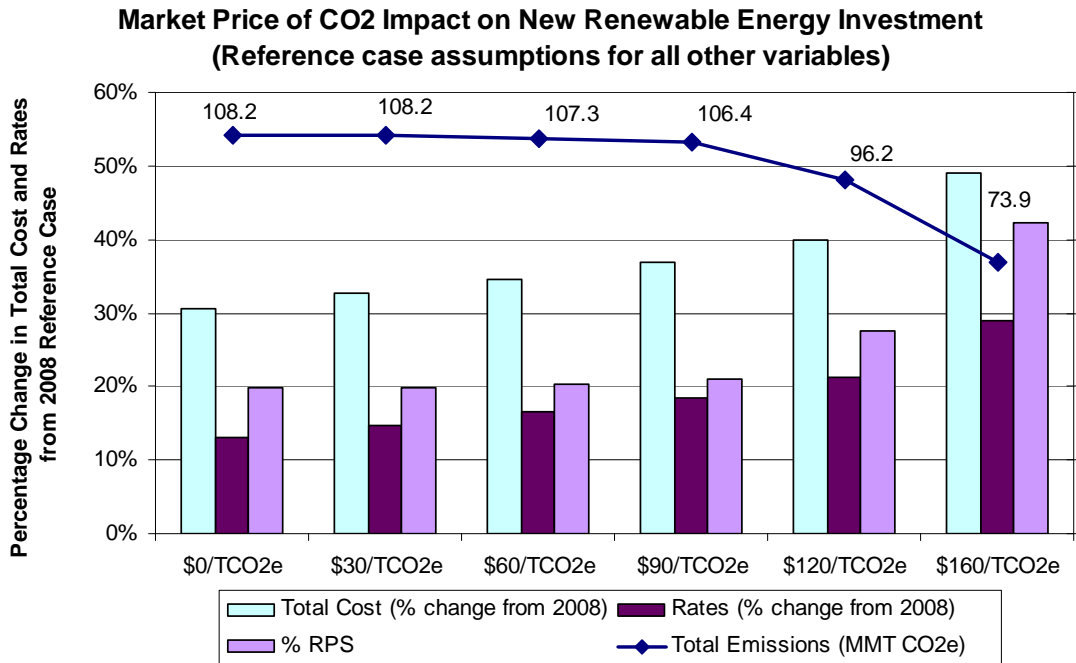


Figure 5. Effect of CO<sub>2</sub> market price on new renewable energy investment (2008\$).

### Results

Figure 6 shows the renewable MAC curve for the \$160/tonne market clearing price. The high market clearing price allows a large amount of solar thermal generation to be built.

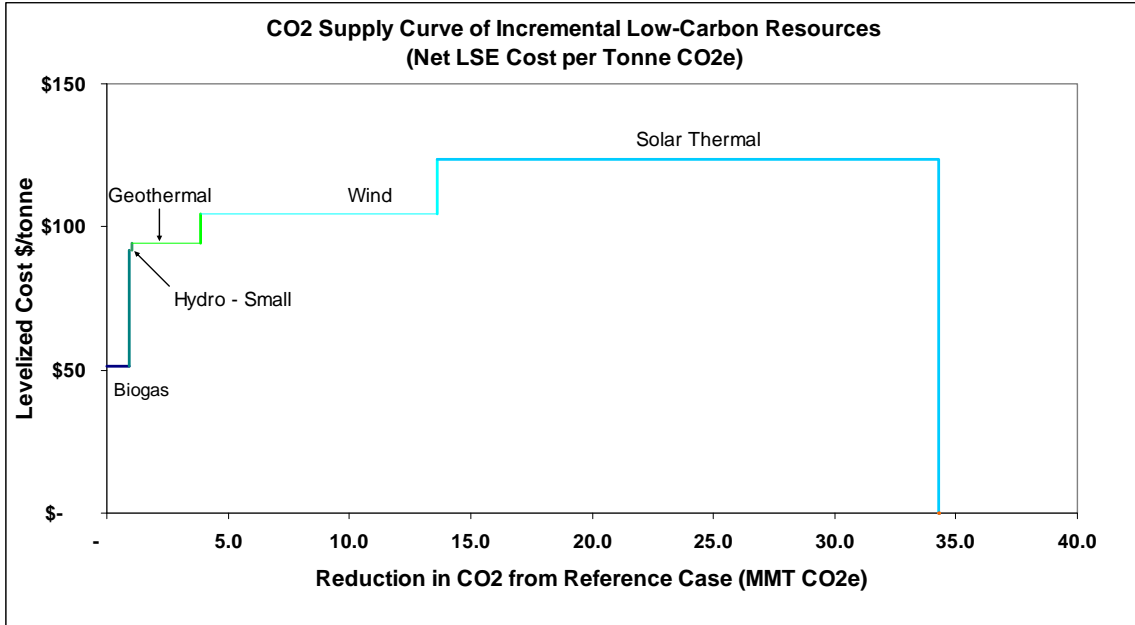


Figure 6. Supply curve for new renewable energy resources (2008\$).

With a market clearing price of \$160/ton of CO<sub>2</sub>e, the increase in renewables from the 20% RPS reference case is 1,594 GWh of biogas, 14,302 GWh of Geothermal, 209 GWh of Small Hydro, 32,668 GWh of Solar Thermal, and 23,114 GWh of Wind respectively. The quantity and price reductions are shown below in Table 13.

Table 13. Quantity and price reductions

Abatement Option	Potential Reduction (MMt CO <sub>2</sub> e/yr in 2020)	Cost (\$ per tonne)
Biogas	0.9	\$49.6
Small Hydro	0.1	\$89.5
Geothermal	2.83	\$91.4
Wind	9.7	\$102.1
Solar Thermal	20.7	\$120.6

The model also shows where this renewable energy comes from because the model loads supply generation in combination with transmission. Table 14 below shows the GWh of renewable generation added by transmission cluster.

Table 14. Renewable resources by transmission cluster

Renewable resources by transmission cluster	
Alberta	0
Arizona-Southern Nevada	0
Bay Delta	750
British Columbia	0
CA - Distributed	250
CFE	0
Colorado	0
Geysers/Lake	0
Imperial	6000
Mono/Inyo	1500
Montana	0
NE NV	0
New Mexico	0
Northeast CA	3000
Northwest	0
Reno Area/Dixie Valley	0
Riverside	4500
San Bernardino	1500
San Diego	3000
Santa Barbara	500
South Central Nevada	0
Tehachapi	6000
Utah-Southern Idaho	0
Wyoming	0

In the reference scenario, California meets its goals for the 20% RPS by 2020. This means that in the reference scenario 2,339 MW are added in the Imperial transmission cluster and 4,394 MW are added in the Tehachapi transmission cluster.

*Limitations and next steps*

The results presented here do suffer from some limitations. Perhaps the most apparent one is that while we do obtain an estimate of the costs of loading a discrete amount of different renewables, in practice there will be a smooth MAC curve for each resource and varying costs of different projects. This detail does not at present enter the final curve we generate. In addition there remain uncertainties about how the costs of renewable energy generation will evolve over time, especially if increasing technology learning takes place. These uncertainties however inevitably afflict attempts at forecasting the penetration of technologies that are not yet completely mature.

As a consequence, while a good beginning has been made towards modeling power generation in order to estimate carbon savings potential, it remains necessary to update and refine assumptions. New investments in energy efficiency, renewable energy and transmission capacity will change the reduction potential and cost of these measures. Assumptions about the extent to which demand response can reduce total load, fuel price assumptions (particularly in modeling natural gas based power generation), and the extent and cost of energy efficiency

measures can all serve to change the extent of renewable energy required and its incremental costs over the reference case.

#### **3.4.4. IGCC coal generation with carbon capture and storage (CCS)**

##### *Background*

Coal-fired electricity generation is a popular prospect for satisfying the United States' growing electricity demand because of the country's abundant and relatively cheap fuel supply. Integrated gasification combined cycle (IGCC) coal combustion has emerged as a potential solution to health and environmental concerns from coal power, which traditionally contributes significantly more NO<sub>x</sub>, SO<sub>x</sub>, Mercury, and CO<sub>2</sub> than other central power technologies. IGCC reduces NO<sub>x</sub> emissions to near the levels from the cleaner fuel, natural gas. It also cuts SO<sub>x</sub> and Mercury emissions and water use compared to pulverized coal. With respect to CO<sub>2</sub>, most literature claims that IGCC offers a cost advantage over pulverized coal plants for installing carbon-capture technology. With the ability to capture 90% to 95% of the coal's carbon, IGCC with carbon capture and storage (CCS) is one way to reduce CO<sub>2</sub> emissions from electricity generation.

Costs of IGCC with carbon capture are higher, and arguably less certain, than most other low-carbon electricity technologies. The McKinsey report suggests a number well under \$50 per metric ton of CO<sub>2</sub>.<sup>85</sup> This number is far lower than the \$255 per ton given in our California cost curve for two main reasons. First, capital costs for IGCC have increased since the McKinsey report, and second, the base case electricity mix differs between California and the world average. While high-emitting coal plants generate 40% of the world's and 50% of the United States' electricity, coal provides only 15% of California's electricity consumption. As a result of its larger proportion of natural gas plants and hydropower imports, California's average CO<sub>2</sub> emissions from electricity are 0.4 kg CO<sub>2</sub>/kWh compared to the United States' 0.6 kg/kWh. Power from coal specifically emits 0.9 kg CO<sub>2</sub>/kWh.<sup>86</sup> Therefore, IGCC in California would compete primarily against natural gas plants, not pulverized coal plants as assumed for general U.S. studies. As a result, IGCC with carbon capture is less effective at reducing CO<sub>2</sub> from the baseline in California than it is in the rest of the US. In fact, it only becomes cost-effective if the CO<sub>2</sub> price threshold exceeds \$255 per metric ton.

##### *Emissions reductions and costs*

If IGCC plants with carbon capture were built to satisfy all of California's added electricity demand from 2015 to 2020, then a total of 6.5 MMt CO<sub>2</sub> could be removed from the baseline emission projection. 2015 was chosen as a reasonable-to-conservative estimate of when IGCC with CCS is mature enough to come online. 2020 is the target year to have 173 MMt fewer overall emissions in California than business as usual.

The California Energy Commission (CEC) estimates electricity consumption to increase in those five years by 20,249 GWh.<sup>87</sup> The difference in emissions between IGCC w/CCS and

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<sup>85</sup> McKinsey and Company (2007). Reducing U.S. Greenhouse Gas Emissions: How Much and at What Cost? US Greenhouse Gas Abatement Mapping Initiative Executive Report.

<sup>86</sup> California Energy Commission (2007). 2006 Net System Power Report. Sacramento, CA.

<sup>87</sup> Ibid.

California's baseline is 0.322 kg CO<sub>2</sub>/kWh.<sup>8889</sup> Therefore, if all new capacity were IGCC w/CCS, 6.5MMtons of CO<sub>2</sub> could be avoided. This difference was calculated from the Clean Air Task Force's estimate of 0.76 kg CO<sub>2</sub>/kWh for IGCC (no capture) times a 90% capture rate. It was then subtracted from California's baseline of 0.4kgCO<sub>2</sub>/kWh, an assumption that predicts California's new electricity capacity would resemble its current mix under business as usual.

Cost factors were compared across several studies. Sources from 2004 and later report capital costs for IGCC and carbon capture 25% to 50% higher than earlier sources. These more recent estimates reflect supply cost increases that affect all new power plants, but they also incorporate cost lessons from demonstration projects that have exceeded initial budgets. We conclude that these higher costs are the most reliable predictions for IGCC.<sup>9091</sup>

As in other parts of this report, preliminary cost values were derived from Energy and Environmental Economics Incorporated (E3).<sup>92</sup> E3 uses higher estimates for all electricity technologies than most studies. In addition to incorporating high capital cost estimates from the industry, E3 multiplies costs by a factor of 1.25 to account for other general cost increases in recent years. Under those assumptions, IGCC with CCS requires \$103/MWh more than new natural gas. This yields a cost of \$320/ton of CO<sub>2</sub> from IGCC with CCS. If we eliminate the 25% cost increase factor, the result is \$255/ton. This number was adopted for our analysis because E3's assumptions before the 25% cost increase are more consistent with, though still higher than, surrounding literature. It is worth noting that a fixed percentage cost increase affecting the entire power industry increases the cost difference between natural gas and IGCC, thus making IGCC more costly as an emission reduction mechanism in California. Other factors contributing to California's high IGCC costs are its higher fuel import costs and labor and operating costs.

### *Discussions*

Another option often discussed regarding carbon capture is retrofitting old coal plants for CCS. While this may have lower costs per avoided ton of CO<sub>2</sub> than building a new IGCC plant with CCS, it would make no appreciable impact on California's emissions, because of the state's small 430 MW fleet of coal plants.

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<sup>88</sup> Clean Air Task Force. (2006). "IGCC Cost Model." from <http://www.psc.wi.gov/cleancoal/documents/4-6-06Meeting/Spreadsheet4-6-06.pdf>.

<sup>89</sup> Hunsaker, L. (2008). Personal Communication on Electric Grid Emission Factor (CARB).

<sup>90</sup> Anderson, S. and R. Newell (2004). "Prospects for Carbon Capture and Storage Technologies." Annual Review of Environment and Resources **29**: 109-142.

<sup>91</sup> Bohm, M., H. Herzog, et al. (2007). "Capture-Ready Coal Plants - Options, Technologies, and Economics." International Journal of Greenhouse Gas Control **1**(1): 113-120.

<sup>92</sup> Energy and Environmental Economics Inc (2007). Inputs to E3 Base Case and Target Cases. Available at [http://www.ethree.com/cpuc\\_ghg\\_model.html](http://www.ethree.com/cpuc_ghg_model.html).

### 3.5. Non-CO<sub>2</sub> gases

Several non-CO<sub>2</sub> gases contribute significantly to the greenhouse effect. Although their volume of emission is small in comparison to CO<sub>2</sub>, non-CO<sub>2</sub> gases have a higher warming potential and then contribute to approximately 30 % of the human-induced greenhouse effect. Methane, nitrous oxide and fluorinated gases are the three most important non-CO<sub>2</sub> GHG gases.

Methane is a greenhouse gas that has a global warming potential (GWP) about 21 times higher than carbon dioxide. The most important sources of methane emissions in California are from agriculture and livestock, and waste management. This report reviews the potential in emissions reductions and the mitigation costs in these two sectors.

Nitrous oxide (N<sub>2</sub>O) is emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste. Its GWP is 310 higher than CO<sub>2</sub>. In this report, there are no specific measures that target only N<sub>2</sub>O gases. N<sub>2</sub>O reductions are rather the by-product of measures that bring reductions of other GHG gases.

Fluorinated gases comprise various synthetic gases, mainly hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. They are also called the high Global Warming Potential (high-GWP) gases because of their GWP is estimated to be 100 to 24,000 times higher than CO<sub>2</sub>. Fluorinated gases are emitted from various industrial activities. In California, their main sources are from insulation, refrigeration, air-conditioning, aerosol, the semiconductor industry and electricity transmission and distribution systems.

Table 15. Summary estimates for non-CO<sub>2</sub> gases

Measure	Emission Reduction (MMTCO <sub>2</sub> e)	Costs (\$/Mt CO <sub>2</sub> e)
Manure Management, estimated with other Biogas sources (see section 3.4.3)	1	\$34
Conservation Tillage	1.2	\$6
Waste Management	2.3	\$42
Recycling	3	\$23
Reduced Methane Venting and Leaks in Oil and Gas Systems	1	\$1
High-GWP: mobile sources	3.1	\$55

High-GWP: stationary sources	10.4	\$10
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### 3.5.1. Manure management

#### *Background*

Manure from livestock emits GHGs through the process of anaerobic digestion. Anaerobic digestion produces a gas containing methane (50-75%), CO<sub>2</sub> (25-45%), and small amounts of hydrogen, nitrogen, and hydrogen sulfide.

Reductions in GHGs, more particularly methane, can be achieved via manure management practices that encompass several types of control options. Adoption of anaerobic digesters is the option that has the most potential to increase methane capture, particularly for large-scale farming operations. In anaerobic digesters, manure biodegrades under more or less controlled conditions, and the biogas produced is captured. The simplest configuration of digesters, covered lagoon, consists to cover an existing manure storage lagoon, and capture the biogas that is emitted. In more complex configurations (plug flow, fixed film, and complete mix digesters), the temperature, moisture, and/or residence time of the manure in the digester is adjustable to provide optimal biogas production.

The biogas collected can simply be burned in a flare, providing no benefits except the conversion of methane to CO<sub>2</sub>. However, combustion of biogas can also be used to provide heat and/or electricity for use on the farm or sale to the grid. Some of the heat is often routed back to the digester, because faster and more complete degradation (with production of more biogas) can be achieved at higher temperatures. Biogas could also potentially be purified to pipeline quality and sold through the natural gas pipeline network, or used as transportation fuel.

#### *Emissions reductions and costs*

According to the California Biomass Collaborative,<sup>93</sup> the volume of biomass from agricultural activities, for the year 2005, available for electricity generation (*technical potential*) represents about 29% (9.6 cubic feet per year, BCF/y) of the total biomass resources available in California (33.6 BCF/y). About half of the potential biomass resources from agriculture is from animal manure. Dairy cow farming is an important contributor, with a potential estimated at 1.9 BCF/y. In terms of electricity generating capacity, the overall technical potential from biomass is 34,650 GWh for the year 2005. The potential from agriculture alone is 7,605 GWh, with 2,893 GWh from animal manure (1,060 GWh dairy cow farming).

<sup>93</sup> California Biomass Collaborative (2005). Biomass Resource Assessment in California, Consultant Report in Support of the 2005 Integrated Energy Policy Report. Sacramento, CA, California Energy Commission.



The Climate Action Team<sup>94</sup> suggests that emission reductions of approximately 1 MMt could be achieved in 2020 through the use of biogas digesters. Overall, the total costs for the measures have been estimated to \$45 million (2006 dollars, at a 5% interest rate). The total benefits associate to the use of biogas has been estimated to \$9 millions. CAT's estimate of the net cost per ton of emission reduction is then \$36 per tonne CO<sub>2</sub>e.

These estimates of the costs and potential for emissions reductions are very uncertain. For instance, a report from ICF consulting<sup>95</sup> proposed a potential for emissions reductions of 6.24 MMt CO<sub>2</sub>e in 2020 at an average cost of \$4 per tonne of CO<sub>2</sub>e or \$26 per tonne of CO<sub>2</sub>e, for respectively 4% and 20% discount rates. From this standpoint, CAT's estimate seems then conservative. The large potential for emission reduction proposed by ICF is however controversial. It relies on highly favorable assumptions regarding the rate of market penetration of manure management systems.

The net cost estimate provided in the CAT report also appears to be conservative. However, there is substantial heterogeneity in the installation and maintenance costs of biodigesters. Our analysis of the total costs and potential for emission reduction of different biodigesters installed in California has shown that costs can vary from -\$50 per tonne of CO<sub>2</sub>e to \$100 per tonne of CO<sub>2</sub>e. The type of biodigester, size of the farm and end-use for energy are important factors.

For the present analysis, we recommend using an estimate that would be consistent with the CAT report and that will explicitly account for the potential for electricity generation from anaerobic digesters. The E3 calculator provides an estimate for biogas electricity generation in California. Although, this estimate aggregates all sources of biogas, and does not only consider gas from manure management, we recommend this estimate. By using this estimate, we explicitly address issues of double-counting that could arise because of the RPS requirements. In Section 3, we comment on the methodology to compute emission reduction potentials and costs for biomass electricity generation. Our calculations suggest that 1 MMt of CO<sub>2</sub>e could be reduced at a cost of \$34 per tonne of CO<sub>2</sub>e from biogas (all sources). This estimate does not include the 20% requirement from RPS.

#### *Discussions and future research*

We recognize that a greater transparency in the analysis could be achieved by using an estimate that is specific to manure management and does not aggregate all sources of biogas.

Furthermore, several institutional barriers to the installation of anaerobic digesters have been identified, notably farmers inertia to adopt new technologies. In this context, the diffusion of anaerobic digesters should benefit from the experience of others. Such dynamic effects should be incorporated in future analysis.

### **3.5.2. Biomass in agricultural sector**

#### *Background*

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<sup>94</sup> Climate Action Team (2006). Climate Action Team Report to Governor Schwarzenegger and the Legislature. Sacramento, CA, California Environmental Protection Agency.

<sup>95</sup> ICF Consulting (2005). Emission Reduction Opportunities for Non-CO<sub>2</sub> Greenhouse Gases in California, California Energy Commission Report 2005-018.

Although, most of the methane emissions in the agricultural sector are associated to livestock management, other agricultural activities have a significant potential for emissions reductions by contributing to electricity generation from biomass resources.

In California, biomass resources are notably available from prunings and tree and vine removals from orchards and vineyards, field and vegetable crop residues, and food processing operations. Altogether, it has been estimated that the technical potential for electricity generation of these resources for the year 2005 was about 4700 GWh. The California Biomass Collaborative (2005) suggests that biomass electricity generation potential from agricultural resources could grow by as much of 40% by the year 2020. This increase is attributable mainly to assumptions regarding improvement in the technology rather than the growth in biomass resources itself.

#### *Emissions reductions and costs*

Just as was done for biogas, we use the E3 calculator to estimate the potential for electricity generation from solid biomass. The estimate aggregates all sources of biomass. Our calculations suggest that electricity generation from biomass comes at a high cost and has a modest potential for emissions reductions, i.e., 0.7 MMt CO<sub>2</sub>e at a cost of \$190 per tonne CO<sub>2</sub>e.

### **3.5.3. Alternative management practices in agriculture**

#### *Background*

The three greenhouse gases that are in a flux with the agricultural systems are CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O. Agricultural soils act as both sinks and sources of these three gases during the course of different processes such as decomposition, photosynthesis, nitrification, denitrification and so on. It has been reported in a number of studies that alternative management practices can aid in mitigating greenhouse gas emissions from agriculture. This mitigation of greenhouse gases essentially can occur through an increase in the sequestration of atmospheric CO<sub>2</sub> or through reduction in the emission of CH<sub>4</sub> and N<sub>2</sub>O (another source of mitigation that can be included here is the reduction in fuel use leading to lower CO<sub>2</sub> emissions). The alternative management strategies that can achieve one or both of the above and considered in this study include:

- a) **Reduced tillage intensity:** Reduced tillage encompasses a number of alternative tillage practices that disturb soil to varied degrees. These include no-tillage, minimum tillage, and conservation tillage. Conservation tillage, in particular, is defined as “a tillage system using 40% fewer total passes than the number of passes in the conventional system for that crop, when all passes of equipment are included”. Conservation tillage practices aid in mitigating GHGs by disturbing the soil to a lesser extent thus causing less decomposition (and consequent release) of soil carbon.
- b) **Cover cropping:** Cover cropping involves growing crops for non-commercial purposes during the off-season for the additional benefits that are associated with this practice (e.g. conservation of soil, suppression of weeds, attracting beneficial insects, etc). This practice leads to GHG mitigation by increasing the inputs to soil carbon content in the form of plant biomass. The focus of the study used in this report is on legumes which are the most widely used cover crops (because of their ability to increase Nitrogen content through fixation).
- c) **Organic practices:** Organic farming practices are based on minimal off-farm inputs (such as fertilizers and synthetic pesticides) and are geared towards promoting the

ecological balance of natural systems. Organic residues (such as manure) are used instead of fertilizers and alternative weed control practices (such as hand-weeding and alternative tillage) instead of pesticides. Like cover cropping, these practices also lead to mitigation through increased carbon inputs to soil.

#### *Emissions reductions and costs*

As mentioned in Brown et al.,<sup>96</sup> the policy of converting crop lands to forests is not an attractive one in California owing to the higher productivity and land costs. Thus the above described measures (and their various combinations) might represent the more relevant of strategies for GHG mitigation from agricultural systems. The Stanford team is using a study conducted by researchers at UC Davis for the California Energy Commission<sup>97</sup> in order to estimate the potential and costs of mitigating GHG emissions via alternative management practices. However, as noted in the study, the evaluation of these strategies is fraught with a number of issues such as permanence, verification, and uncertainty.

The first step in the methodology followed by the UC Davis study was to calibrate and validate a biogeochemical model DAYCENT. This model would simulate the GHG emissions and the crop yields under various alternative management practices. The data for this was obtained from four field sites in Sacramento and San Joaquin valleys. Conventional practices were compared with a range of alternative management practices which included conservation tillage, cover cropping, organic practices and their possible combinations.

The model was then used to obtain the decreases in yields and GHG emissions at a regional level under various crop rotations – weather – soil type combinations along with various alternative management practices and their combinations. The mean potential from the two different regions under different management practices have been found to range from 0.68 MgCO<sub>2</sub>e per ha per yr (conservation tillage) to 2.6 MgCO<sub>2</sub>e per ha per yr (organic practice + cover crop) for Sacramento valley and 0.49 MgCO<sub>2</sub>e per ha per yr (organic practices) to 1.87 MgCO<sub>2</sub>e per ha per yr (organic practice + cover crop) for San Joaquin valley.<sup>98</sup> There was also a significant amount of variability observed in these numbers with the standard deviation being in the order of the mean itself. Owing to the large inherent variability of these potentials, it was concluded that contracts over many fields will be necessary to minimize the overall uncertainty.

Following this, the study focused on Yolo County for conducting an economic analysis of these practices. Six different crops were chosen on the basis of three factors towards this purpose. The three factors here include acreage percentage, commercial relevance and participations in standard rotations of the county. The DAYCENT model was first adjusted to correspond to the Yolo County and a survey was then carried out to determine the behavioral aspects of farmers under various payment programs. The survey also provided researchers with inputs which allow computation of the costs associated with various management practices.

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<sup>96</sup> Brown, S., A. Dushku, et al. (2004). Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California, Winrock International Report PiER Energy-Related Research 500-04-068F. Sacramento, CA, California Energy Commission.

<sup>97</sup> De Gryze, S., R. Catala, et al. (2008). An Integrated Assessment of the Biophysical and Economic Potential for Greenhouse Gas Mitigation in California Agricultural Soils., California Energy Commission Report CEC-500-2008-039.

<sup>98</sup> The combination of all three practices was not considered since it was thought to be infeasible. It is further noted in the study that Reduced Tillage might be the most feasible option given the ease of monitoring and implementation.

The costs of different management practices were computed by estimating the difference in the net present values of the profits corresponding to conventional and alternative practices. The change in GWP (Greenhouse Warming Potential) corresponding to each management practice, as mentioned above, is an output of the DAYCENT model. The DAYCENT model and the survey data were thus combined to produce the cost curves for possible sequestration from different types of crops among the survey data. (The cost curves here were constructed for each of the crops and management practices). A sample curve corresponding to wheat is shown below.

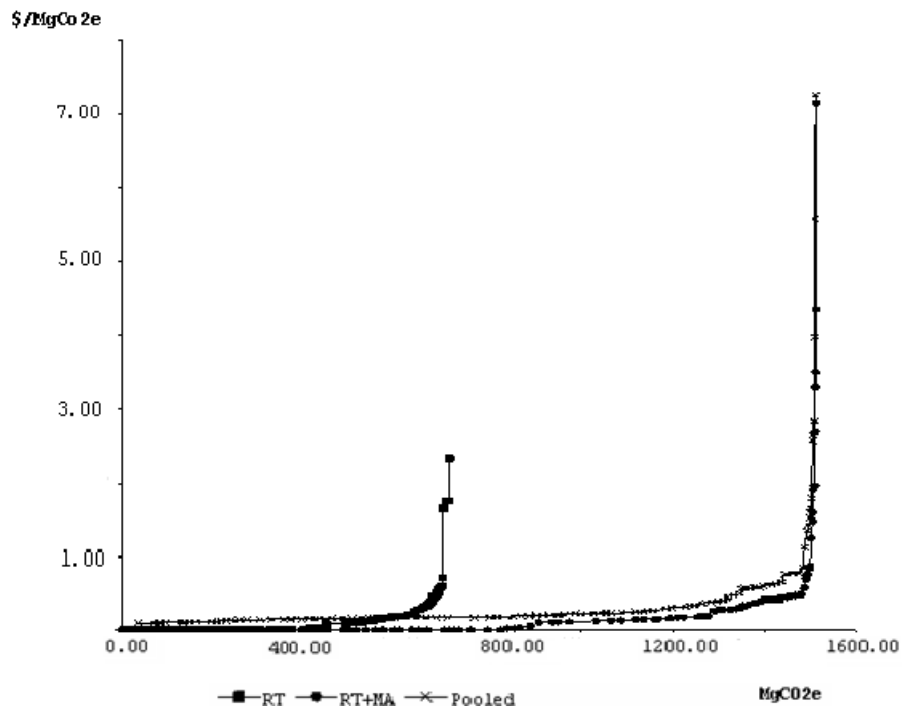


Figure 7. Cost curve for wheat.

These curves were used to obtain the maximum potential per hectare and also the cost at which this occurs in case of each crop. The areas for the six different crops in 2006 for the whole state were then obtained from the department of food and agriculture’s California Agricultural Resource Directory 2007<sup>99</sup> (Table 16).<sup>100</sup> The maximum potential corresponding to each crop type (in MgCO<sub>2</sub>e per ha) from the CEC study were then scaled up according to the area occupied by each crop type in CA to obtain the total potential.

Table 16. Areas of six different crops

Crop Type	Wheat	Rice	Corn	Sunflower	Tomatoes	Safflower
Area (1000 acres)	520	526	563	18	334.4	56

<sup>99</sup> California Department of Food and Agriculture. (2007). "California Agricultural Resource Directory." Retrieved June, 2008, from <http://www.cdfa.ca.gov/statistics.html>.

<sup>100</sup> In cases where data was not available from CFDA, the 2002 US census of agriculture data was used instead.

This computation revealed that the potential for these six crops would be in the order of 1.21 MMt CO<sub>2</sub>e at an average cost of about \$6 per tonne. An additional assumption while arriving at the number for potential reduction was that reduced fuel usage (e.g. due lower number of tractor passes) here contributes to about 0.25 Mg CO<sub>2</sub>e per hectare. Note that this is on the lower end of the estimates for the contribution of this factor.

The above number for potential mitigation is still likely to be underestimated though. Only six crops were evaluated for the given alternative management practices. There are a number of other crops that are grown in CA and these systems might offer significant potential for GHG mitigation as well. The 1.21 MMt CO<sub>2</sub>e number, thus, might not represent the full potential for these practices in CA. However, this is the number that is being used in the overall Stanford MAC curve since the information on corresponding costs of mitigation is available only for this number.

In addition to the above, there are other concerns that need to be acknowledged in this context. Firstly, the scaling of numbers from one county can add to the uncertainty in addition to the inherent uncertainty as noted in the UC-Davis study. The reasons for such a difference include factors like variation across counties in terms of soil structure,<sup>101</sup> climate, management practices, etc. One area where further area is needed to reduce the uncertainty around potential is the quantification of N<sub>2</sub>O flux. As identified in the report, additional data collection and validation efforts are needed in order to achieve this. Lastly, the costs here, in addition to being assumed to be the same at state and county levels, are likely to be underestimated due to the fact that the risks associated with the alternative management practices are not included in the cost computations.

### **3.5.4. Waste management**

#### *Background*

Methane is generated in landfills due to the decomposition of organic matter. Landfill gas is captured by drilling wells and by using a pipeline system to collect the gas. Once collected, the gas can be flared, used for heating or used for electricity generation. Natural gas injection and biofuels production are also possible.

There is much uncertainty in the process to compute landfill emissions. Consequently, there exist different estimates for the inventory of landfill emissions in California. Under AB1803, CARB has been mandated to produce the California emission inventory for the year 1990. Previously, it was CEC that has such responsibility. CARB staff has made significant revisions in the methodology to compute landfill emissions. As a result, the latest inventory of landfill emissions differs by a wide margin from the previous estimates.

CARB's new methodology uses a mathematical model coupled with estimates of waste-in-place (WIP) in Californian landfills to compute methane emissions. The model, the Mathematically Exact First-Order Decay Model, is from the Intergovernmental Panel on Climate Change.<sup>102</sup> WIP estimates are from the California Integrated Waste Management Board

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<sup>101</sup> Brown et al. for instance, reported that the GHG mitigation could range from 0.35 to 0.61 MMT/yr/ha depending on the soil type.

<sup>102</sup> IPCC (2006). IPCC Guidelines for National Greenhouse Gas Inventories. National Greenhouse Gas Inventories Programme. H. Eggleston, L. Buendia, K. Miwa, T. Ngara and K. Tanabe. Japan, IGES.

(CIWMB). Model parameters are calibrated from various sources, mainly the IPCC and USEPA.

#### *Emissions reductions and costs*

CARB<sup>103</sup> has recommended methane capture as a discrete early action. Three types of measures specific to methane capture have been identified to meet the reductions proposed by the discrete early actions mandate:

1. Install new methane control systems at landfills currently without control systems;
2. Maximize landfill methane capture efficiencies through optimizing landfill design, operation, and closure/post-closure practices; and
3. Increase recovery of landfill gas that is currently flared as a biomass renewable energy source to avoid emissions from fossil fuel energy sources.

According to CARB, these three measures altogether should bring an overall emission reduction of the order of 2 to 4 MMt CO<sub>2</sub>e by 2020. This estimate is consistent with the analysis produced by CIWMB staff and reported in the Climate Action Team Report.<sup>104</sup> The analysis by CIWMB reports the emission reduction potentials for each of the three measures.

CIWMB has suggested that with the installation of new control systems at landfill sites a feasible emission reduction for 2020 would be of the order of 0.5 MMt CO<sub>2</sub>e, but that the technical potential is much higher. Assuming, that all landfills that did not have a control system in 2005 would adopt one and assuming a rate of efficiency of 75% for methane capture, additional potential for emissions reductions of the order of 1.6 MMt CO<sub>2</sub>e could be possible, for an overall reduction of 2.1 MMt CO<sub>2</sub>e. This estimate is however overly optimistic. Firstly, because it assumes that methane capture for small landfill (below 500,000 tonnes of waste in place) is possible, but in reality current technologies have few ability to capture methane for these landfill size.

Secondly, because some landfills, due their age, will simply stop emitting methane before 2020. These two effects then bias the technical potential for emissions reductions toward an overestimation. Considering these factors, to account for the additional technical potential, we assume that in addition to the feasible emission reduction of 0.5 MMt CO<sub>2</sub>e identified by CIWMB, additional reductions are possible only at higher costs and for a reduction of the order of 0.5 MMt CO<sub>2</sub>e. The remaining 1.1 of the technical potential (i.e., 2.1-0.5-0.5=1.1) is considered too costly with current technology.

Regarding the emissions reductions associated with the energy recovery from landfill methane, CIWMB has proposed that landfill gases could contribute to produce 2205 GWh of electricity, which would bring an emission reduction due to avoided electricity generation from other sources of approximately 1.2 MMt CO<sub>2</sub>e. The Climate Action Team report (2007) has used a number of similar magnitude for their analysis. There is much uncertainty in this estimate. A study from the California Biomass Collaborative (2005) suggested that overall the technical

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<sup>103</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

<sup>104</sup> Climate Action Team (2006). Climate Action Team Report to Governor Schwarzenegger and the Legislature. Sacramento, CA, California Environmental Protection Agency.

potential for electricity generation from biomass sources is of the order of 60,000 GWh for 2020, with about one third of the technical potential attributable to municipal waste. Therefore, according to this source, the technical potential for electricity generation from landfill gases could be roughly 20,000 GWh in 2020. This number is large in comparison to the estimate of 2,205 GWh proposed by CIWMB. It suggests that CIWMB is conservative and emphasizes the role of the barriers for the development of landfill gases to energy systems.

In addition to electricity generation, landfill gases can also be used as vehicle fuels. The potential to use biogas for LNG and CNG technologies is considered non-negligible. Several demonstration projects have been financed throughout California. According to CIWMB, these demonstration projects alone could contribute to a reduction of 0.15 MMt CO<sub>2</sub>e (in avoided emissions). A potential expansion of production could provide an overall emission reduction of 1.0 MMt CO<sub>2</sub>e. Note however that is unclear to which extent the biogas used for vehicle fuels will be diverted from the biogas used for electricity generation. Issues associated to double counting must then be considered.

Table 17 summarizes the estimates for the potential of emissions reductions associated to landfill methane capture. In the first two columns, the feasible reductions to meet the mandate of CARB discrete early actions are presented. In the third column, the technical potential is presented. Note that this number is not correct for double counting. Finally, the last column presents our adjusted estimate of the technical potential. This is the estimate that we recommend for the MAC curve because it better reflects the feasible potential for emissions reductions taking into account more aggressive measures than the one considered under the discrete early actions.

Table 17. Emission reduction potential for landfill methane capture measures

Type of Measure	Emissions reductions, Recommendation for Discrete Early Actions		Additional Potential Reduction 2020: Full Technical Potential (MMtCO <sub>2</sub> e)	Additional Potential Reduction 2020: Adjusted Estimate (MMtCO <sub>2</sub> e)
	2010 (MMtCO <sub>2</sub> e)	2020 (MMtCO <sub>2</sub> e)		
Measure 1: Install New Control Systems	0.2	0.5	1.6	0.5
Measure 2: Increase Energy Recovery from Landfill Methane (Offsets)	0.4	1.2	1	-
Measure 3: Increase Capture Efficiencies	0.4	1.3	-	-
Total	1	3	2.6	0.5

Based on analysis from CIWMB staff, the Climate Action Team Report (2007) proposes an aggregate costs and benefits estimate for the three measures. For a reduction of 2.66 MMt CO<sub>2</sub>e, total costs are estimated at \$61 million (2006 dollars, at a 5% interest rate) and savings are estimated to be as high as \$171 million. The cost per tonne for these three measures together are then estimated at approximately -\$41 per tonne CO<sub>2</sub>e.

This negative cost is attributable to the large benefits associated to an increase in electricity generation with landfill gases. This quantity is however subject to double counting in the Climate Action Team report. Furthermore, CIWMB staff have emphasized that even absent problems related to double-counting, there is a large uncertainty regarding the amount of electricity that can be produced from an increase in energy recovery from landfill gases.

Uncertainties in the cost estimates are also considered to be non-negligible for the first and third measures. CARB in collaboration with CIWMB are now working to improve these estimates. According to private communications with CARB and CIWMB staff, the cost estimates presented in the background analysis of the Climate Action Team report will be substantially revised. Based on the report of California Biomass Collaborative,<sup>105</sup> analysts at CIWMB have suggested that the costs would be lower than expected. Table 18 presents the costs for each measure as reported in the background analysis of the Climate Action Team report (2007). We also report expected direction of changes for future estimates.

Table 18. Costs estimates for three types of measures for landfill methane capture

Type of Measure	Total Costs: Capital, Operating and Maintenance Costs (\$/tonne CO <sub>2</sub> e)	Total Costs: Capital, Operating and Maintenance Costs (cents/kWh)	Expected Directions of Change for Future Estimates (\$/tonne CO <sub>2</sub> e)
Measure 1: Install New Control Systems	50	-	35 Decrease (~40%)
Measure 2: Increase Energy Recovery from Landfill Methane (Offsets)	135	3.4-10	80 Decrease (~40%)
Measure 3: Increase Capture Efficiencies	25	-	17 Decrease (~40%)

There are a number of important conclusions to draw from Table 18. First, excluding the benefits associated to electricity generation, the mitigation costs of methane from landfill gases

<sup>105</sup> California Biomass Collaborative (2005). Biomass Resource Assessment in California, Consultant Report in Support of the 2005 Integrated Energy Policy Report. Sacramento, CA, California Energy Commission.



are significant for the three measures that will be used to comply with the discrete early actions plan. The costs and the benefits associated to the second measure are crucial to determine the overall cost-effectiveness of the three measures altogether. Assumptions about the price of electricity and the efficiency of methane capture technologies for energy recovery are then determinant to evaluate the net costs of landfill methane capture. Meanwhile, the current estimates will be subject to important revisions. Future estimates will most likely reduce the current cost estimates. Finally, the present cost estimates do not consider dynamic effects and technological change. More precisely, there are several reasons to believe that biomass production technologies would benefit from research and development effort and learning-by-doing effect, which the present cost estimates do not account for.

The Climate Action Team report suggests that landfill methane capture is a highly cost-effective measure that could bring a moderate quantity of emission reduction. The cost-estimate used adopted for this report relies on an analysis from CIWMB staff that is currently being updated. Future estimates of the costs of the technologies are likely to be lower. Regarding the estimates of the benefits this is unclear. We however know that the projected quantity of electricity produced is subject to double-counting. Furthermore, the Climate Action Team only considers the feasible reductions that will allow to meet the mandate of the Discrete Early Actions. As discussed above, further reductions might be possible. For the AB 32 MAC curve we have then proposed the following approach to compute the costs and potential for emissions reductions of methane from landfills.

Firstly, for costs and emissions reductions estimates associated to control systems alone, i.e. excluding energy recovery, we explicitly distinguish between maximizing efficiencies of installed control systems, installing new systems, at moderate costs, and a more aggressive measure that considers installation of new systems at higher costs. Costs estimates are from the California Biomass Collaborative and CIWMB. CIWMB has estimated the costs for installing new systems at moderate costs (\$33 per tonne CO<sub>2</sub>e). We have use this cost has a benchmark to estimate the costs of the other two measures. Maximizing methane capture efficiency costs are considered to be 50% percent of \$33 per tonne CO<sub>2</sub>e. The more aggressive adoption of control systems is considered to cost 25% percent more than the moderate costs measure. Estimates for the potential for emissions reductions for each of these measures are from CIWMB and reported on Table 18 above. Figure 8 summarizes the costs and emissions reductions estimates associated to control systems for methane capture at landfill sites.

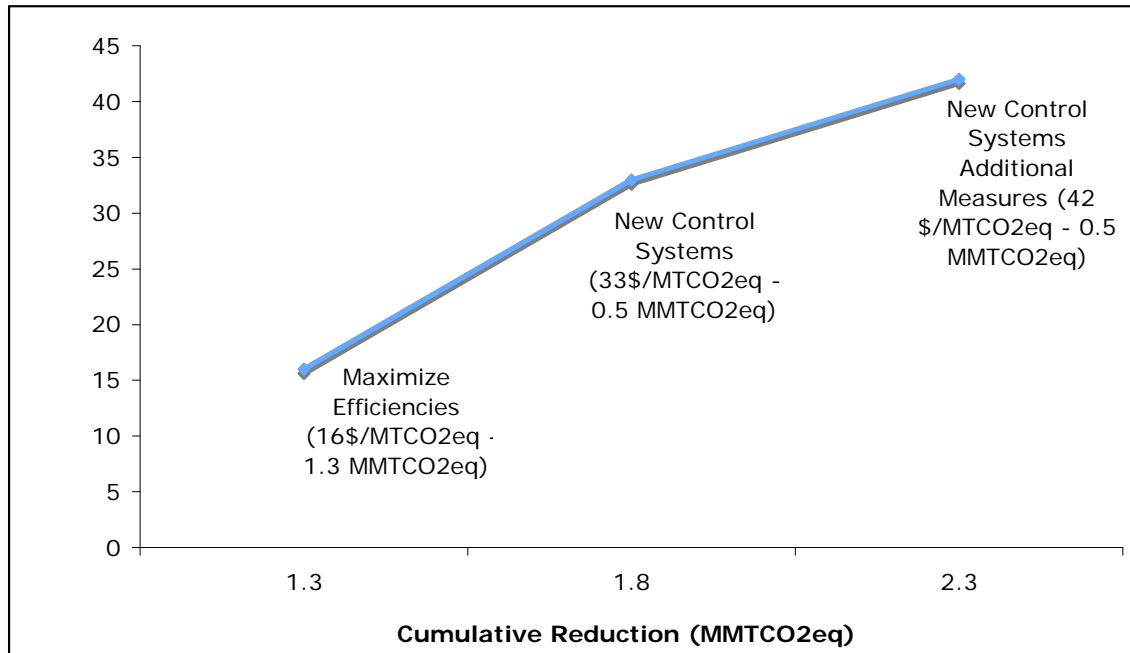


Figure 8. MAC curve for control systems of methane capture from landfills

For the measure that considers energy recovery from landfill gas, we recommend the estimates provided by the E3 calculator. E3 calculator estimates the potential for emissions reductions and costs associated to biogas electricity production. Estimates for landfill gases to energy systems are included in this estimate. We review this estimate in more detail in our section discussing the E3 modeling of renewable energy measures (Section 3.4.3).

### 3.5.5. Recycling

#### *Background*

According to the Climate Action Team and CARB staff, substantial emissions reductions can be achieved with recycling and composting measures. Emissions reductions could be achieved principally by avoiding methane emissions at landfills, increasing carbon sequestration at compost and mulch facilities, reducing fossil fuels through production of biofuels, and reducing energy use associated with the harvesting of virgin materials that are replaced with recyclable materials. CIWMB is responsible to provided the background analysis for this estimate. In the Climate Action Team report<sup>106</sup> and the draft version of the CARB Scoping Plan,<sup>107</sup> preliminary estimates of the potential for emissions reductions and costs for this measure are provided.

These estimates are however highly uncertain, both from the perspective of the potential for emissions reductions and the costs.<sup>108</sup> To accurately estimate this measure, it would require a full

<sup>106</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

<sup>107</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

<sup>108</sup> Cost estimates for recycling and composting are not provided in the draft version of CARB Scoping Plan.

life-cycle analysis. Furthermore, this type measure should be estimated in parallel with landfill methane capture because the two measures are substitute to a certain extent.

The quantification of the costs for recycling faces further difficulties. Recycling incurs costs to households, which are mostly time and then difficult to quantify. In the same vein, there are behavioral issues associated to the large-scale adoption of recycling among the population, which also need to be accounted for. One other challenge is that part of the benefits from this measure comes from the opportunity costs of the avoided harvesting of virgin materials, which is difficult to estimate if it contributes to reduce emissions in California or elsewhere.

#### *Emissions reductions and costs*

We recognize that there is a true potential for emissions reductions in California from recycling and composting efforts. Uncertainty is however large. In a desire to account for this potential, we recommend to use the estimates provided by the Climate Action Team.<sup>109</sup> The potential for emissions reductions in 2020 estimate is 3 MMt CO<sub>2</sub>e and the overall costs are \$69 million. The cost effectiveness measure is then \$23 per tonne CO<sub>2</sub>e.

However, this estimate should be seen as a placeholder for our curve and further research and data are needed to improve this estimate. We strongly emphasize that a full life-cycle analysis would be necessary to provide a sensible estimation. Also, we should be careful while we attribute emissions reductions from this measure to not double-count reductions from substitute measures, such landfill methane capture and electricity production from other biomass resources (e.g. food waste).

### **3.5.6. Reduced methane venting and leaks in oil and gas systems**

#### *Background*

Methane is vented and leaked from natural gas systems during normal operation, routine maintenance and system problems. This measure aims to implement improved management practices that can reduce direct methane emissions from the state's gas infrastructure. The measure will target natural gas and oil systems, wells, gas processing and storage facilities, pipeline operators, and utilities.<sup>110</sup>

#### *Emissions reductions and costs*

We use the analysis performed in the CAT report to quantify the cost effectiveness of the reduced methane venting measure. The report estimates venting and leaks in the state can be reduced approximately 50% by 2010 using currently available technology. This amounts to a GHG abatement of 1 MMt CO<sub>2</sub>e in 2010. The analysis assumes this same abatement level will continue until 2020, thus the abatement potential in 2020 will also be 1 MMt CO<sub>2</sub>e.

The CAT analysis estimates the measure cost to be \$1/ton CO<sub>2</sub>e. Costs derive from the purchase and installation of new technology as well as additional costs for inspection and enforcement. Savings are determined as the market value of the abated emissions of methane. The CAT Analysis reports costs and savings of \$10 million and \$9 million respectively. Current

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<sup>109</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

<sup>110</sup> Ibid.

cost analysis of this measure is very limited though many technologies have been identified to enable the reduction; further investigation into the costs of these technologies is needed.

### **3.5.7. High-GWP gases from mobile sources**

#### *Background*

Hydrofluorocarbons (HFC) gases are used principally for insulation, refrigeration and air-conditioning purpose. Their use in motor vehicle air conditioning (MVAC) systems and stationary refrigeration and air conditioning (SRAC) systems contribute significantly to the emission of greenhouse gases due to fugitive emissions and leakages during operation of the systems and when disposed at their end of life.

High-GWP gases are not emitted from a particular sector. Numerous measures that target different products have then been identified to reduce emissions. The present report follows the classification of the measures adopted by CARB.

CARB is currently recommending six measures to reduce HFC emissions:

1. Motor Vehicle Air Conditioning Systems: Reduction of Refrigerant Emissions from Non-Professional Servicing;
2. SF<sub>6</sub> Limits in Non-Utility and Non-Semiconductor Applications;
3. High GWP Reduction in Semiconductor Manufacturing;
4. Limit High GWP Use in Consumer Products;
5. High GWP Reductions from Mobile Sources;
6. High GWP Reductions from Stationary Sources.

The measures that have the greater potential to reduce HFC emissions are the one that target MVAC and SRAC systems, i.e., the fifth and sixth measures above. These measures are reviewed below. The other four measures considered by the CARB Scoping Plan are left for future analysis.<sup>111</sup>

#### *High GWP reductions from mobile sources*

Four measures to reduce HFC emissions from mobile sources have been identified:

1. Replacing GWP with low-GWP refrigerants and increase efficiency in new MVACS;
2. Reduction of leaks in MVACS;
3. Enforcement of the federal ban on releasing HFCs during servicing and dismantling of MVACS; and
4. Refrigerant Recovery from Decommissioned Refrigerated Shipping Containers.

#### *Low-GWP refrigerants and increased efficiency in new MVACS*

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<sup>111</sup> These measures have been recommended as discrete early actions. According to preliminary estimates, they have a low potential for emissions reductions (approximately 1 MMTCO<sub>2</sub>eq altogether).

Substitution of HFC-134a, the most common refrigerant in MVACS, toward low-GWP gases and increased efficiency in vehicle thermal load reduction for new vehicles can bring important emissions reductions. Research and development efforts are now under way to find suitable gases to replace HFC-134a and improve vehicle design to enhance thermal load reduction.

The background analysis provided for the Climate Action Team report and CARB Scoping Plan suggests that by substituting HFC-134a by HFC-152a in all new vehicles (light-duty vehicles and others) sold in California, a reduction of 2.5 MMt CO<sub>2</sub>e could be achieved. This estimate is conservative. In addition to the proposed substitute, HFC-152a, several other gases with lower GWP could also be used, but the technologies for these gases are more uncertain. Furthermore, the above estimate does not consider the potential for emissions reductions associated to changes in vehicle design.

The cost associated to this measure would affect the capital cost of vehicle with MVAC system using HFC-152a. The incremental capital costs can then be used as a proxy of the social costs of the measure. According to the Climate Action Team, the sum of the incremental capital costs associated to this measure is \$163 million in 2020.

Although conservative, we recommend using the estimates provided in the CAT report. This estimate should be seen as a lower bound regarding the potential for emission reduction. Further reductions, more likely at higher costs, could be possible if gases with lower GWP become suitable substitutes to HFC-134a in new MVAC systems.

#### *Reduction of leaks in MVACS*

Leakage in MVACS are often undetected or left unfixed by vehicle owners. As a result, a program that will mandate the verification of MVACS could bring non-negligible emissions reductions. A proposed measure to reduce emissions of GWP gases is then to add MVACS inspection to the California vehicular inspection and maintenance program, SmogCheck.

According to the Climate Action Team, this measure could bring emissions reductions of the order of 0.5 MMt CO<sub>2</sub>e in 2020.<sup>112</sup> The cost estimate of this measure is \$6 million. It includes the instrument costs that professionals would need to perform the inspection and the training costs.

For our MAC curve, we recommend the estimate provided in the CAT report.<sup>113</sup> The costs methodology is consistent with a calculation of the social costs of the measure.

#### *Enforcement of the federal ban on releasing HFCs during servicing and dismantling of MVACS*

An existing regulation of the USEPA prohibits the venting of refrigerant, HFC included, when equipment, such MVAC, is serviced and dismantled. According to CARB, a better compliance with this regulation could bring significant emissions reductions.

As a preliminary estimate, CARB has estimated that better compliance with the federal regulation solely at the dismantling stage could bring an emission reduction of the order of 0.07

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<sup>112</sup> Various assumptions have been used to calculate this estimate. They are documented in the background analysis (appendix B) of the CAT report (2007) and in the document: *HFC-134a as an Automotive Refrigerant - Background, Emissions and Effects of Potential Controls*, (August 6, 2004).

<sup>113</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

to 0.3 MMt CO<sub>2</sub>e in 2020. More recently, CARB staff has considered that the reduction would be of the order of 0.1 MMt CO<sub>2</sub>e in 2020. This estimate is however highly uncertain. Little is known about the extent of the compliance of dismantlers in California. Furthermore, the type of HFC found in MVAC systems in 2020 is highly likely to be substituted. Assumptions for this estimate are documented in the background analysis (appendix B) of the CAT Report. No cost estimate is provided by the Climate Action Team.

Using similar assumptions that the Climate Action Team regarding the number of vehicles that will be dismantled in 2020 (1.1 million), the proportion of vehicles that will use HFC-134a as a refrigerant (50%), the quantity of refrigerant left in MVAC systems at their end-of-life (80 g) and degree of compliance of dismantlers (low), we have calculated a cost estimate for this measure. According to ICF Consulting,<sup>114</sup> the dismantling costs are in average between \$1.5 to \$5.0 per lb. Using the high range of this estimate, \$4.0 per lb, the costs of this measure is \$0.4 million. For a reduction of 0.1 MMt CO<sub>2</sub>e, the cost estimate for our MAC curve is \$4 tonne CO<sub>2</sub>e. Although, we consider the high range of the estimates for the potential for emissions reductions and costs, these estimates are more likely to be conservative. Excluded from the estimates are the reductions and costs associated to the enforcement of the regulation at the servicing stage, which could be non-negligible.

#### *Refrigerant recovery from decommissioned refrigerated shipping containers*

According to CARB, this measure has a low potential for emissions reductions in 2020 (< 0.1 MMt CO<sub>2</sub>e). We thus do not include this measure.

### **3.5.8. High-GWP reductions from stationary sources**

Several measures have been identified to reduce direct and indirect GHG emissions from stationary RAC sources. Direct emissions refer to the emission of refrigerant, mainly HFC, due to leakage and improper dismantling. Indirect emissions refer to the emissions associated to the energy used in the manufacturing and operating of these systems. The Climate Action Team report and the CARB Scoping Plan provide estimates for the potential for emissions reductions for direct and indirect sources.

According to the latest estimates provided in the Scoping Plan, high-GWP gases emissions from stationary sources could be reduced by as much of 11.6 MMt CO<sub>2</sub>e. Six different measures have been identified by CARB to achieve this reduction:

1. High GWP Recycling and Deposit Program;
2. Specifications for Commercial and Industrial Refrigeration;
3. Foam Recovery and Destruction Program;
4. SF<sub>6</sub> Leak Reduction and Recycling in Electrical Applications;
5. Alternative Suppressants in Fire Protection Systems; and
6. Residential Refrigeration Early Retirement Program.

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<sup>114</sup> ICF Consulting (2005). Emission Reduction Opportunities for Non-CO<sub>2</sub> Greenhouse Gases in California, California Energy Commission Report 2005-018.

The first two measures contribute for more than a fair share of the emissions reductions. Foam recovery and destruction has also a high potential. However, most of the emissions reductions for this measure would be achieved through destruction of ozone depleting substances, which are gases not currently cover by Kyoto and AB 32.

#### *High GWP recycling and deposit program*

Stationary air conditioning and refrigeration equipment used in the non-residential sector use important quantities of refrigerant. Substantial emissions reductions could be achieved from actions aiming at monitoring, reducing leaks and avoiding emissions at servicing and end-of-life of equipment.

According to CARB,<sup>115</sup> by reducing HFCs, this measure could achieve as much as 6.3 MMt CO<sub>2</sub>e in emissions reductions.

CARB has estimated that the total monitoring and repair costs associated to this measure could be approximately \$9 million in 2020. However, reduction in leaks and better servicing are also synonym of benefits, notably due to reduced refrigerant. CARB has estimated that these benefits could be as high \$75 million. It suggests that the net social costs of this measure would be negative.

#### *Specifications for commercial and industrial refrigeration*

Better design of commercial and industrial refrigeration systems could also achieve significant emissions reductions, both direct and indirect.

For this measure, CARB recommendation is to establish performance limits that would aim to reduce leak rates, from approximately 20-30% to 2% and increase energy efficiency.

According to the latest CARB estimate, the potential for emissions reductions, both direct and indirect, would be about 4 MMt CO<sub>2</sub>e in 2020. However, for the purpose of building our MAC curve, using this estimate raises an issue of double-counting because the reduction of indirect emissions due to energy-efficiency gains have already been accounted in our estimates of energy-efficiency measures. We partly correct for double-counting by subtracting the emissions reductions associated to energy-efficiency of refrigeration systems in the retail food system sector alone, which according to the Climate Action Team Report is 1.2 MMt CO<sub>2</sub>e.

In the technical appendices of CARB Scoping Plan, a cost estimate for this measure is suggested. Again, this estimate accounts for improved energy-efficiency. The Climate Action Team reports a preliminary estimate of the incremental capital costs attributable to better specification of refrigeration systems in the retail food sector: \$66.5 MMt CO<sub>2</sub>e in 2020. For our MAC curve, we recommend this estimate, although it is highly uncertain and subject to future research.

#### *Foam recovery and destruction*

In addition to measures that target HFC gases, measures that target emissions of other high-GWP gases, such as CFC and CHFC, have the potential to bring significant emission reduction. CFC and CHFC are ozone depleting substances (ODS) and they are not considered as GHG gases under Kyoto nor AB 32. Given that they are still important contributors of GHG, we

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<sup>115</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

review a measure that has the potential to reduce ODS, in addition to HFC, significantly. However, we do not consider the reduction in GHG attributed to ODS.

Plastic insulating foams are an important source of high-GWP gases. They are widely used in refrigerators, freezers, buildings, commercial refrigeration units, and transport refrigerated units.

High-GWP gases used in insulating foams include ODS: CFC-11 and HCFC-141b, in addition to HFC-134a, and HFC-245fa. ODS are not listed under Kyoto and AB 32 as GHG. However, it is believed, particularly in California, that they should be addressed.

Emissions from insulating foams occur because of inappropriate disposal of the waste foams. The common practice is to simply landfill foams when appliances reach their end-of-life or when building are being demolished or renovated. Emissions of high-GWP GHGs from waste foams in California are significant. They are estimated to be about 9 MMt CO<sub>2</sub>e annually.

CARB has not proposed specific strategies to reduce emissions associated to insulating foams. The most optimistic scenario is that a set of strategies will allow to recover 100% of the waste foam gases, which would bring emissions reductions of the order of 8 to 9 MMt CO<sub>2</sub>e annually if this measure was implemented today. For 2020, the potential for emissions reductions would be less because the stock of appliances and buildings using foams with ODS is gradually declining over time. The estimate for the potential for emission reduction in 2020 is 6.3 MMt CO<sub>2</sub>e, where emission reduction from HFC alone has been estimated to be of the order of 1 MMt CO<sub>2</sub>e.

CARB has collected information regarding the cost of foam recovery for appliances. The costs range from \$6.50 to \$48 per tonnes CO<sub>2</sub>e dependently if the recovery is performed with an automated system or manually. Cost estimates for building foam recovery are higher. CARB refers to an analysis performed for the IPCC, which suggests an estimate in the range of \$70 to \$100 per tonne CO<sub>2</sub>e. Following CARB analysis, we recommend to use the upper value of this estimate.

### 3.5.9. High-GWP gases summary

Table 19 summarizes the potential for emission reduction and cost estimates for both mobile and stationary high-GWP gases. Some measures recommended by CARB have not been considered, but these measures are marginal.

An important conclusion to draw from Table 19 is that there is considerable heterogeneity in the cost-effectiveness of the different measures. In the MAC curve, we report only the aggregate estimate for mobile and stationary sources but these estimates may conceal important disparities across the different measures. Note that our estimates are lower than the CARB Scoping Plan estimate because our estimates are corrected for issues of double counting.

Table 19. Summary emission reduction and cost estimates for high-GWP gases

Measure	Emission Reduction Potential (MMt CO <sub>2</sub> e)	Cumulative Costs (million \$)	Cost (\$/tonne CO <sub>2</sub> e)



High GWP Reductions from Mobile Sources	3.1	169.4	55
Low-GWP Refrigerants and Increase Efficiency in New MVACS	2.5	163	65
Reduction of Leaks in MVACS	0.5	6	13
Enforcement of the federal ban on releasing HFCs during servicing and dismantling of MVACS	0.1	0.4	4
High GWP Reductions from Stationary Sources	10.4	100.5	10
High GWP Recycling and Deposit Program	6.3	-66	-10
Specifications for Commercial and Industrial Refrigeration	2.8	66.5	24
Foam Recovery and Destruction Program (HFC only)	1	100	100
Total	13.5	270	20

### 3.6. Industrial sectors

Table 20. Summary estimates for industrial sectors

Measure	Emission Reduction (MMt CO <sub>2</sub> e)	Costs (\$/MTCO <sub>2</sub> e)
Cement: Fly Ash Substitution	2.4	\$0
Cement: Fuel Switching	2.2	\$119
Cement: Improved Efficiency	0.84	-\$33
Petroleum Refining	3.5	-\$109
Petroleum & Gas Production	3	-\$62
Other materials production	1.1	\$100
Industrial Carbon Capture & Storage	0	X

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#### 3.6.1. Cement industry

This analysis evaluates current cement demand in the state of California, associated sources of CO<sub>2</sub> emissions, as well as several CO<sub>2</sub> mitigation opportunities and their corresponding costs. Since the information publicly available was very limited, a bottom up approach was taken by gathering data and analysis from multiple sources, putting them together, and calculating the results. All of calculations are not shown in detail here, but can be found in the excel attachment. The sources of information include the Portland Cement Association (PCA), American Coal Ash Association (ACAA), American Concrete Institute (ACI), Energy Information Agency (EIA), United States Geological Survey (USGS), California Energy Commission (CEC), CALTRANS, McKinsey & Co, the World Business Council for Sustainable Development (WBCSD), the Vattenfall Report, and several cement and concrete industry companies.

##### *Background*

First it is important to clarify the difference between cement and concrete. The most common type of cement used today is a type called Portland cement. Portland cement is produced by combining crushed limestone, clays, sand and lots of heat (other additives are sometimes used in smaller percentages). The output is a powdery substance used to make concrete. Concrete is typically made of 11% Portland cement, 41% crushed gravel (aggregate),

26% sand, 16% water, and 6% air.<sup>116</sup> Concrete is the material used to construct roads, walkways, foundations, buildings, bridges, etc. When discussing cement production, it is the raw material (Portland cement). When discussing concrete, it is the finished product used in construction.

*World cement production*

Cement demand and production is increasing at a rapid rate throughout the world. As nations industrialized and cities continue to grow, cement usage has more than doubled from 1992-2005, and has grown almost 5 fold since 1970. As seen from the figure below, its growth rate has far surpassed other commonly used materials.<sup>117</sup> The CO<sub>2</sub> emission from cement production is the highest among these materials, accounting for approximately 5% of global CO<sub>2</sub> emissions.

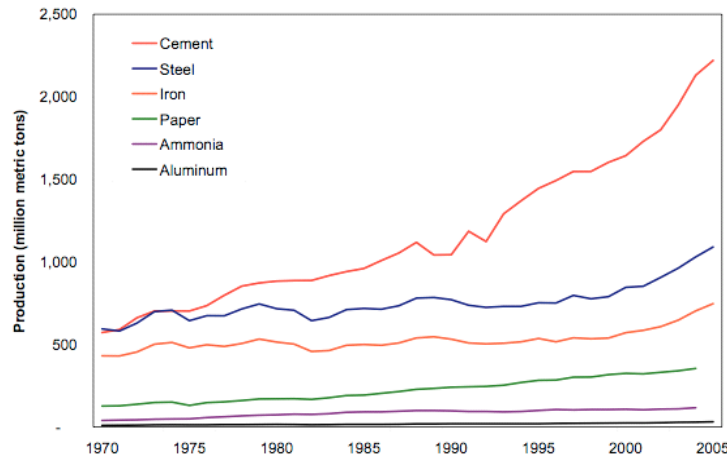


Figure 9. Growth in materials production.<sup>2</sup>

The 2005 cement production is roughly estimated to be 2.3 billion metric tons, with approximately 2.1 billion metric tons of CO<sub>2</sub> emissions.<sup>118</sup> As world economies grow, so will the usage and production of cement. In 2020, production is estimated at approximately 3.5 billion metric tons (3.2 billion metric tons CO<sub>2</sub> emissions), with the majority of growth coming from the Asia/Pacific region.

<sup>116</sup> Portland Cement Association. (2008). "Portland Cement Association Website." from [www.cement.org](http://www.cement.org).

<sup>117</sup> US Geological Survey. (2007). "Cement." from <http://minerals.usgs.gov/minerals/pubs/commodity/cement>.

<sup>118</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

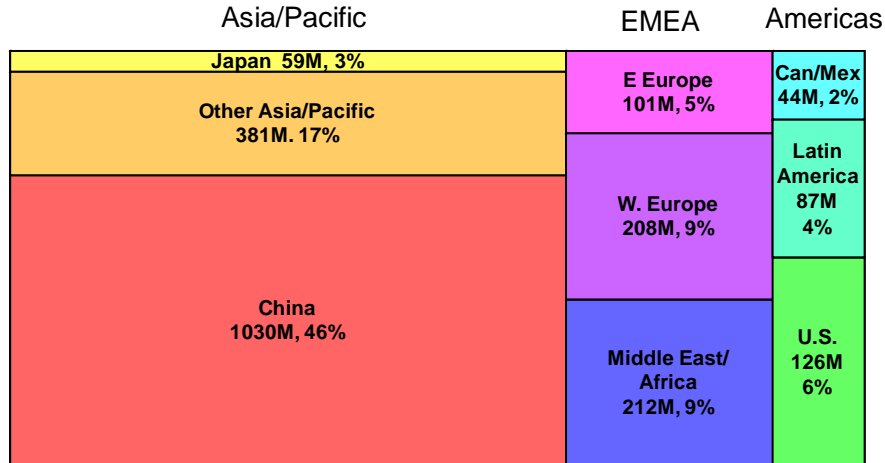


Figure 10. 2005 cement production.<sup>119</sup>

### United States cement production

In the United States, when looking at CO<sub>2</sub> emissions from the production of cement, there is almost a 99% correlation; with 1 metric ton of cement production equaling approximately 1 metric ton of CO<sub>2</sub> emissions. This ratio shows that the US is one of the dirtiest producers of cement. But this ratio can be misleading. The United States uses a greater amount of clinker in each metric ton of cement produced, while other nations will add significant amounts of clays and pozzolans into their cement mixtures, thereby reducing the emissions per ton. The US tends to save the pozzolan additives for use in finished products (concrete).

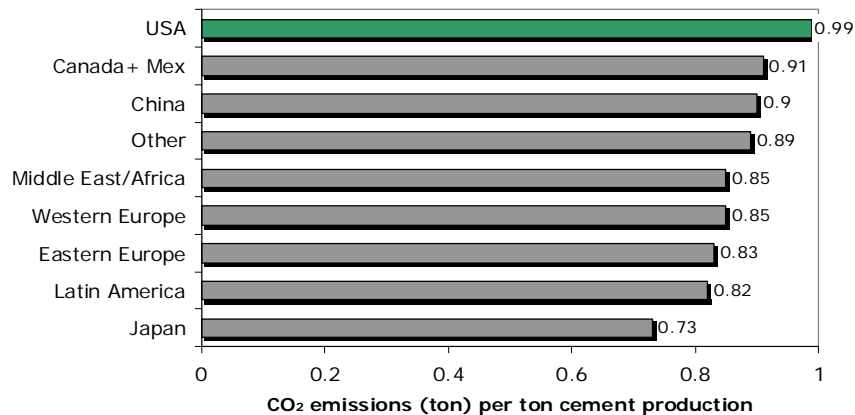


Figure 11. CO<sub>2</sub> emissions per ton of cement production.<sup>120</sup>

In the United States today (2007), approximately 130 million metric tons (MMt) of cement is consumed annually.<sup>121</sup> The primary uses of cement are for residential construction, public

<sup>119</sup> Ibid.

<sup>120</sup> Ibid.

<sup>121</sup> Portland Cement Association (2007). Annual Yearbook 2007, North American Cement Industry. Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

highways roads, commercial buildings, and other public construction projects. Most US demand has consistently been met with domestic production, but with rising costs, since the early 80's there has been an increasing trend towards international imports. In 2005, US cement imports were estimated to be approximately 25% of demand.<sup>122</sup>

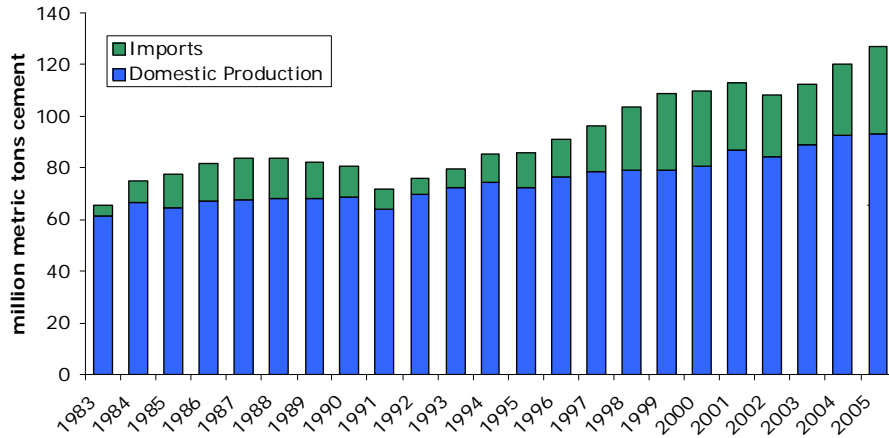
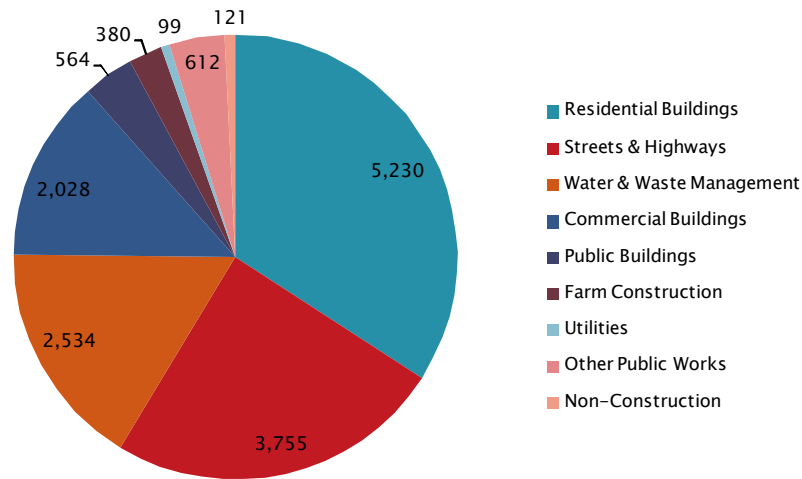


Figure 12. US cement demand, production, and imports.<sup>123</sup>

*California cement production*

In California, demand for cement has maintained a steady growth rate, while production has increased at a modest pace. In 2005, cement demand in the state was 15 MMt. The primary uses include residential buildings, highways, streets, water management, and waste management. The figure below breaks down the primary uses of cement within California in 2005.<sup>124</sup>



<sup>122</sup> Portland Cement Association (2005). Annual Yearbook 2005, North American Cement Industry.

<sup>123</sup> Ibid.

<sup>124</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

Figure 13. 2005 Cement usage in California (thousands of tonnes).

In state production of about 12 MMt was only able to partially meet consumer needs. The difference was supplied primarily by international imports. Since cement has a significant amount of weight, land transportation tends to be much more expensive than barge, where economies of scale help reduce transportation costs per ton. The figure below shows the current trends for cement demand and production in California, assuming that a constant 20% of demand is met by imports.<sup>125</sup> The percentage of imports is expected to increase, but there is a great deal of uncertainty in how much that increase will be.

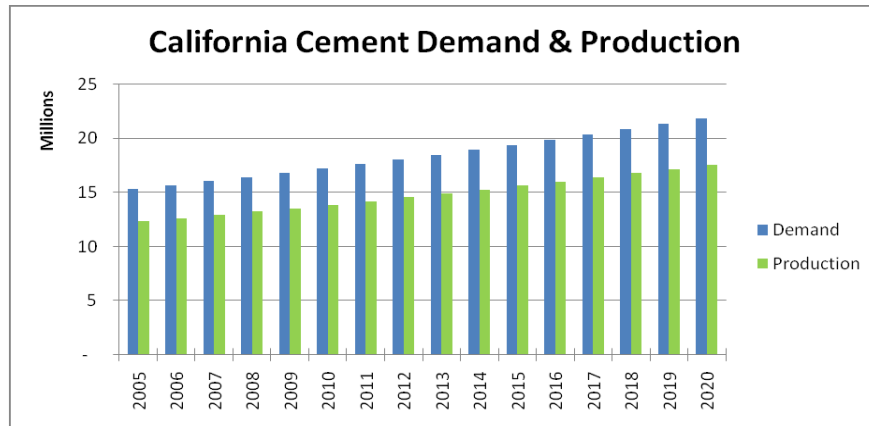


Figure 14. California cement demand and production.<sup>6</sup>

*Energy consumption and emissions*

Cement production is an energy intensive operation. The primary uses of energy are during the removal of raw materials, combustion of the fuel used for heat, specialty vehicles, and power generation (from the grid or in-house). In 2005, California cement production used approximately 52 million gigajoules of energy.<sup>126</sup> The figure below breaks down the sources of energy.

<sup>125</sup> Ibid.

<sup>126</sup> Portland Cement Association (2005). Annual Yearbook 2005, North American Cement Industry.

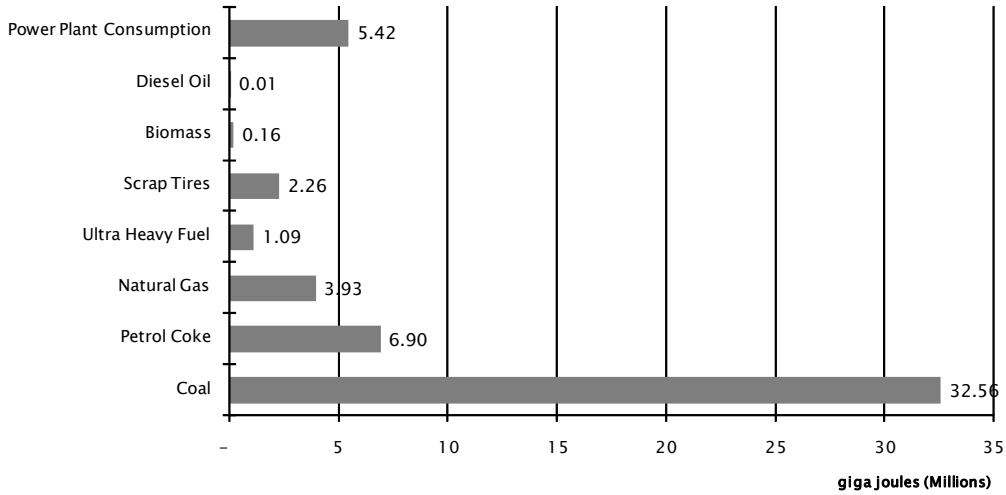


Figure 15. California energy consumption by source.

Energy consumption was then translated into CO<sub>2</sub> emissions using PCA reports and analysis. In 2005, California CO<sub>2</sub> emissions totaled more than 11 MMt. This amount does not include the emissions generated by out of state production and transportation. The figure below breaks the emissions down by sources.

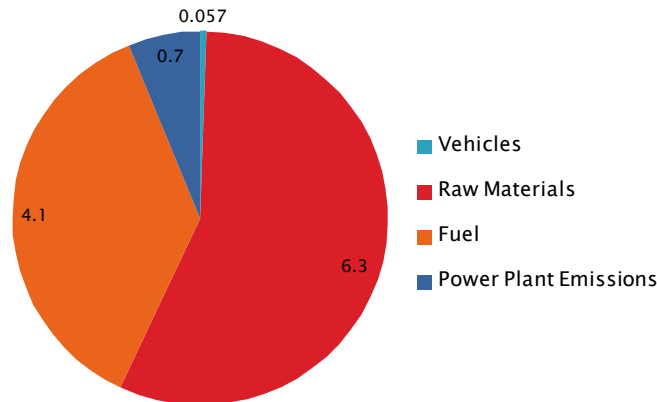


Figure 16. 2005 California CO<sub>2</sub> emissions by source (MMt).<sup>127</sup>

The greatest quantity of emissions, 56.4% or 6.3 MMt, comes from the removal and production of the raw materials. As the limestone is pulled from the earth, CO<sub>2</sub> is released. When the limestone is heated in the kiln, chemical reactions cause the majority of CO<sub>2</sub> emissions to be released.

The second largest amount of CO<sub>2</sub> emissions come from fuel consumption, 36% or 4.1 MMt. Coal remains the most common fuel used to generate heat required in the kiln. Coal is also the dirtiest emitter of CO<sub>2</sub>, releasing approximately 95 kg of CO<sub>2</sub> per gigajoule (GJ) of energy. Power plant emissions, which are counted when a cement production facility draws power from

<sup>127</sup> Ibid.

the grid, is the third largest source of emissions, 6.2% or about 0.7 MMt. The table below highlights the sources of emissions from cement production.

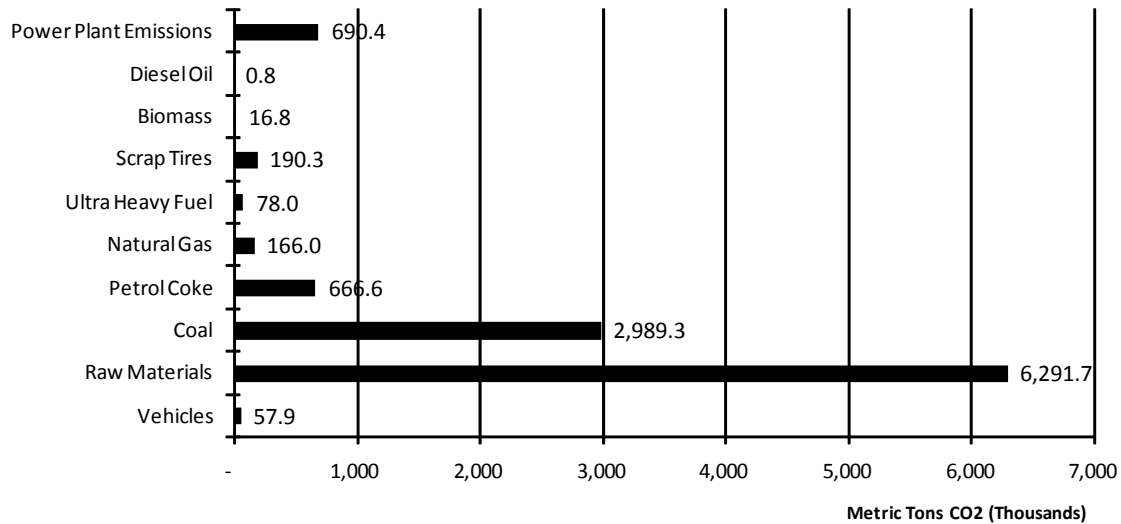


Figure 17. Detailed California emissions by source (thousands of metric tons).

Different fuel sources generate different amounts of emissions per GJ of energy generated. More efficient fuels are able to generate greater amounts of energy with less CO<sub>2</sub> released. The table below breaks down common fuel sources and the amount of CO<sub>2</sub> released per GJ. Coal and petrol coke are the dirtiest fuels, while natural gas is significantly cleaner.

Table 21. Emissions per fuel source (kg CO<sub>2</sub>/GJ)<sup>128</sup>

	Emissions (kg CO <sub>2</sub> /gJ)
Diesel Oil	74
Biomass	110*
Scrap Tires	85
Ultra Heavy Fuel	77
Natural Gas	56
Petrol Coke	93
Coal	95

\*Biomass emissions do not include lifecycle analysis

Looking forward into 2020, California cement demand is projected to increase to approximately 22 MMt, with an estimated 18 MMt coming from in-state production. With the increase in in-state production, CO<sub>2</sub> emissions are expected to total approximately 16 MMt. This amount does not include the emissions generated by out of state production and transportation.

### *Emissions reductions and costs*

<sup>128</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.



There are several opportunities for CO<sub>2</sub> reduction from cement. Each one has its own set of cost implications, CO<sub>2</sub> reduction, and uncertainty. There may also be overlap between each reduction method. In this analysis each opportunity for reduction was calculated individually. Table 22 summarizes each opportunity and associated costs.

Table 22. CO<sub>2</sub> mitigation opportunities from cement production in 2020

<b>Mitigation Opportunity</b>	<b>Total Reduction (MMt)</b>	<b>Total Cost (million \$)</b>	<b>Cost per ton (\$/metric ton)</b>
<b>Pozzolan Substitution</b>	2.4	0	0
<b>Fuel Switching</b>	2.2	259	119
<b>Improved Efficiency</b>	0.84	(27.7)	(33)
<b>New Technologies</b>	X	X	X

*Emissions reductions and costs: pozzolan substitution*

One of the most interesting CO<sub>2</sub> mitigation opportunities is by replacing Portland cement with pozzolans in concrete. There are several sources of pozzolans, including fly ash from coal combustion, slag from steel production, and natural volcanic ash. At this time, volcanic ash cannot legally be used in concrete and the supply of slag from steel production in the US is scarce.

Only fly ash from coal combustion has the ability to make a significant impact on CO<sub>2</sub> emissions. There are different types of fly ashes produced, depending on the type of coal plant, efficiency of the plant, the type of coal used, the region of the country where the coal came from, and the coal plant's emission capturing methods. There was a limited amount of information available on the fly ash associated from coal plants in the US. Analysis was performed using EIA and ACAA data on the type of coal consumed from each coal power plant in the US in 2005. That data was used to estimate the amount and type of fly ash produced from each coal plant.

Legally in the US only in-spec Type C and Type F fly ash can be used in construction, depending on individual state guidelines. Fly ash has both benefits and drawbacks when used in concrete mixtures. Benefits include added strength, reduced permeability, and improved resistance; while drawbacks include slower setting time, slower strength gain, and difficulty in workability.

In 2005, 70 MMt of fly was produced in the US,<sup>129</sup> with approximately 21% (15.3 MMt), used in concrete.<sup>130</sup> The total in-spec fly ash available in the US was 19.7 MMt, or 27% of the

<sup>129</sup> American Coal Ash Association (2007). Personal Communication: Private Industry Information and Statistical Analysis.

American Concrete Institute. (2008). "ACI website." from <http://www.concrete.org/general/home.asp>.

<sup>130</sup> American Coal Ash Association (2007). Personal Communication: Private Industry Information and Statistical Analysis.

American Concrete Institute. (2008). "ACI website." from <http://www.concrete.org/general/home.asp>.

total produced. Unused fly ash is commonly disposed of as landfill with smaller amounts used in other applications. In California, fly ash currently replaces approximately 14% of cement demand, or 2.1 MMt.<sup>131</sup>

In 2020, over 112 MMt of fly ash is expected to be produced in the US,<sup>132</sup> with an in-spec usable amount of 13.1 MMt. If California were to substitute 25% of all the Portland cement consumed with fly ash, approximately 5.5 MMt of cement would be replaced. That translates into an increase of fly ash usage by 11%, and a CO<sub>2</sub> reduction of 2.4 MMt. Industry sources are adamant that anything greater than a 25% fly ash mix in concrete would cause delays in construction and would be strongly opposed by the construction industry. Widespread use of more than a 25% fly ash mix in concrete would only occur with mandatory usage laws or incentives for the construction industry.

The cost of fly ash substitution currently mirrors the cost of Portland cement. In 2006, the cost of fly ash was approximately \$98 per tonne, while the cost of Portland cement was also approximately \$98/tonne. These costs vary depending on the region and location in California. Since the costs of fly ash are approximately the same as Portland cement, the current cost of reduction is estimated to be \$0.

#### *Emissions reductions and costs: fuel switching*

Another opportunity to reduce CO<sub>2</sub> emissions is by switching to cleaner burning fuels. Figures 9 and 10 highlight the emissions from fuel sources during cement production. Coal and petrol coke are the most commonly used and dirtiest sources of fuel. If all of the dirtier fuels were replaced by the cleanest, natural gas, there would be a reduction opportunity.

The total energy from fuel required in 2005 was 46.9 million GJ.<sup>133</sup> The CO<sub>2</sub> per GJ from dirtier sources averages to approximately 0.09 tonnes/GJ. Natural gas generates about 0.056 tonnes/GJ. In order to meet 2020 cement production demands of approximately 18 MMt, the expected energy requirements will be 66.7 million GJ. If the current fuel mixture were to remain consistent, that would translate into 5.8 MMt of CO<sub>2</sub> emissions from fuels. If all of the fuel energy were switched to natural gas, the associated CO<sub>2</sub> emissions would total 3.7 MMt, a reduction of 14%, or 2.2 million metric tons.

Calculating the cost of this reduction was a bit trickier. EIA reports the 2006 cost of coal in California at about \$57.6 per short ton, with a projected 1% annual decrease each year thereafter.<sup>134</sup> That translates into a 2020 cost of about \$50/short ton, or \$55.5 per metric ton. That also translates into a cost of about \$2.4/GJ. The 2020 projected cost of natural gas is approximately \$7 per million btu, or \$6.63 per GJ.<sup>135</sup> The increased cost of switching to natural gas comes to \$4.24 per GJ, which brings total fuel costs to \$259 million, or \$119 per metric ton of CO<sub>2</sub> reduced. These costs do not include the capital costs of converting facilities.

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<sup>131</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

<sup>132</sup> US Department of Energy Energy Information Administration. (2008). "Coal (Reports and Statistics)." from <http://www.eia.doe.gov/fuelcoal.html>.

<sup>133</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

<sup>134</sup> US Department of Energy Energy Information Administration. (2008). "Coal (Reports and Statistics)." from <http://www.eia.doe.gov/fuelcoal.html>.

<sup>135</sup> California Energy Commission (2007). 2007 Final Natural Gas Market Assessment. Sacramento, CA.

### *Emissions reductions and costs: improved efficiency*

A third opportunity is to improve the operations and processes of existing cement manufacturing plants in California. There was difficulty in obtaining information on the efficiency of California's 11 active cement manufacturing plants, and 18 total kilns.<sup>136</sup> Several reports on CO<sub>2</sub> reduction, McKinsey, Vattenfall, and the WBCSD discuss the emissions reduction potential from improved efficiency from cement production plants. By taking an average of the total reduction in those reports, and correlating that data for California in 2020, an emissions reduction potential of 0.8 MMT is achievable. The total costs would actually be a savings of almost \$27 million, or a savings of \$33 per metric ton of CO<sub>2</sub> reduced.

### *Emissions reductions and costs: new technologies*

A fourth opportunity and maybe the most promising is the increased number of new technologies on the verge of breaking into the conservative cement and concrete industry. Several new companies, including CalStar of Newark, CA and Calera of Los Gatos, CA are developing new technologies that are able to either reduce the amount of Portland cement required in concrete, and/or capture CO<sub>2</sub> emissions from the production process. The CO<sub>2</sub> reduction potential here is quite large, but it is extremely difficult to quantify these reductions and costs without further detailed information about the expected advance of the technology, all of which is proprietary.

### *Discussion*

In this section the limits and uncertainty of each CO<sub>2</sub> mitigation opportunity are briefly discussed. Fly ash substitution has the potential to make a significant impact on CO<sub>2</sub> reduction, but there are a number of limits and uncertainties which need to be addressed. First, as mentioned earlier, without policy intervention, industry sources were adamant that no more than a 25% fly ash mix would be frequently used in concrete mixtures. This is because the negative attributes of slower set time, and slower strength gain, has the potential to significantly increase the overall time and costs of construction projects. A second limitation is the availability of in-spec fly ash nationwide. As restrictions on nitrogen oxide and sulfur dioxide emissions from coal power plants are strengthened, fly ash is commonly used in the filtering and emissions capturing process. When the fly ash is used, the byproduct is an ash which contains large amounts of mercury and/or sulfur. The high mercury ash is banned from use in concrete by the EPA, while the high sulfur ash brings its own set of complications, including a formidable odor. The figure below shows the changes in fly ash demand, and projected increase to 2010, while also showing the expected availability and expected shortage of in-spec fly ash supply.

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<sup>136</sup> Portland Cement Association (2008). Personal Communication: Private Industry Information and Statistical Analysis.

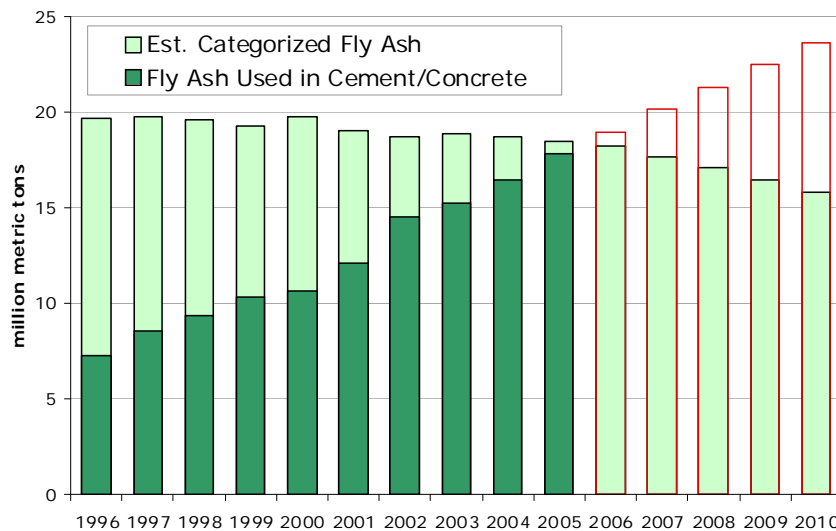


Figure 18. Fly ash availability.<sup>137</sup>

On the positive side, emerging technologies by several companies which are able to beneficiate the out-of-spec fly ash, and bring it in-spec are currently being developed. These technologies, when available, might be able to bridge the shortage gap. A final note on fly ash is that currently there are only 8 coal power plants in California. Most of the fly ash used in California is imported from Utah, Wyoming and Arizona. As demand increases, fly ash imports will have to travel from more distant Midwest power plants, which will increase transportation costs, and possibly raise the cost of fly ash above the cost of Portland cement in California.

When it comes to fuel switching, the primary concern is cost. Coal is cheap, and its costs continue to decline, while the costs of natural gas continue to rise (with a great deal of uncertainty). It will be very difficult to convince cement manufacturing plants to convert from coal to natural gas without policy requirements or financial incentives.

The CO<sub>2</sub> reduction quantity and costs from cement manufacturing efficiency improvements has its own set of uncertainties. The data used comes from national and international sources. It is difficult to predict how efficient California cement plants are today, and how much more efficient they could become. If there is room for improvement, then what is the incremental amount of improvement they can achieve, and what are the associated costs?

An additional discussion topic which has the potential to significantly impact California's cement industry is international cement imports. In 2006, 20% of California demand was met by imports. With increased pressure or costs to reduce emissions, California's cement companies might turn towards shutting down in-state manufacturing and relying more on imports. Currently the majority of imported cement comes from China and Thailand, both of whom already have fairly high amounts of CO<sub>2</sub> emissions from the production of cement. With increased imports, the biggest concern to California will become CO<sub>2</sub> emissions leakage. The

<sup>137</sup> Ibid.

American Coal Ash Association (2007). Personal Communication: Private Industry Information and Statistical Analysis.

table below highlights the percentage of CO<sub>2</sub> emissions in each country which comes from cement manufacturing.

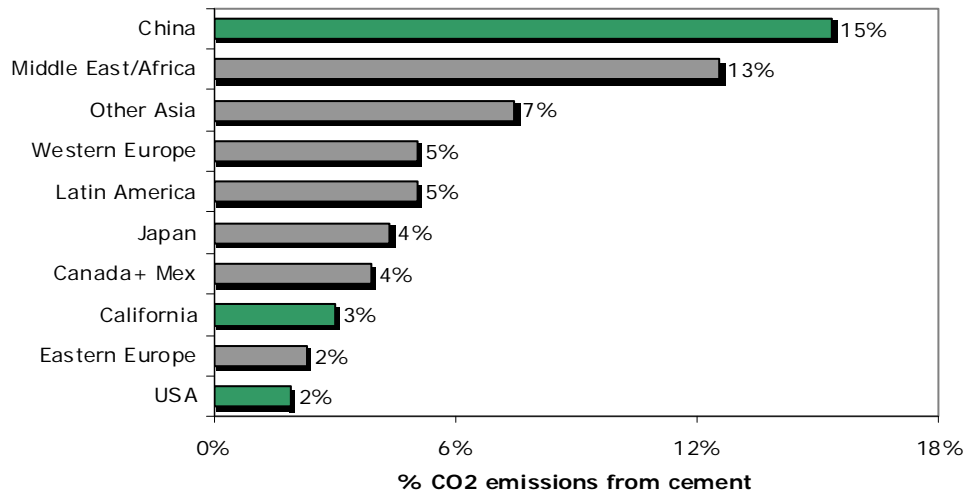


Figure 19. Percentage of emissions from cement.<sup>138</sup>

#### *Future research*

- Further research needs to be conducted on new and emerging technologies and their potential costs and CO<sub>2</sub> reduction.
- Research needs to also be done on the future availability of in-spec fly ash to California. The EPA recently rolled back coal power plant emission standards for SO<sub>x</sub> and NO<sub>x</sub>, will this rollback increase the amount of in-spec availability?
- Research needs to be conducted on the current efficiency of California cement manufacturing plants, and how much improvement is possible.
- Further research on the impact of leakage and the emissions from international cement manufacturers.

### **3.6.2. Petroleum refining**

Petroleum refineries are the largest energy using industry in California and constitute a significant source of GHG emissions in California. As per the GHG inventory,<sup>139</sup> petroleum refining accounted for about 28% of the emissions from the industrial sector, i.e. about 35 MMt CO<sub>2</sub>e. California has about 21 refineries operating with a combined capacity to process over 2 million barrels of crude oil every day.<sup>140</sup> Refineries in California produce a different mix of products when compared to the US national average with a higher emphasis on lighter products and consequently, there are differences in the processes, technologies and energy intensity of these refineries. Our estimates for potential for reduction from the following categories are

<sup>138</sup> Portland Cement Association. (2008). "Portland Cement Association Website." from [www.cement.org](http://www.cement.org).

<sup>139</sup> California Energy Commission. (2006). "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004." Retrieved May, 2008, from [www.arb.ca.gov/cc/inventory/doc/doc\\_index.php](http://www.arb.ca.gov/cc/inventory/doc/doc_index.php).

<sup>140</sup> California Energy Commission. (2006). "California's Oil Refineries." Retrieved February, 2008, from <http://energyalmanac.ca.gov/petroleum/refineries.html>.

based on the numbers released by CARB as a part of the scoping plan.<sup>141</sup> The proposed measures for reducing GHG emissions from refineries include efficiency improvements and reducing fugitive emissions of methane from refineries. A major constraint in evaluating these measures is the availability of data on emissions or energy consumption in these areas.

The complex and heterogeneous nature of refineries and their operations cause significant variation in the amount of opportunity and cost of mitigation through efficiency improvements. Thus, a bottom-up approach where individual refineries are examined would be needed to precisely quantify the amount of GHG reduction through efficiency improvements. In the CARB Scoping Plan, the equipment that could be affected by this measure includes process heaters & boilers, fluid catalytic crackers, hydrogen plants, and flares. In the absence of exact data, the current estimates for GHG emissions, 2 to 5 MMt CO<sub>2</sub>e per year, are only approximations and may need to be changed with availability of data. The capital costs, on the other hand, were estimated to be about \$600 to \$900 million with net annualized savings being \$450 million.

In addition, a small amount of potential is also realized from removal of fugitive methane exemptions from the regulation governing the sources in refineries. This measure is expected to yield 0.01 to 0.05 MMt CO<sub>2</sub>e per year of reduction at an annual cost of \$5 million. Combining all of the above numbers suggests that about 3.53 MMt CO<sub>2</sub>e per year of mitigation is possible at a cost of about -\$109 per tonne of CO<sub>2</sub>e.

A major barrier for evaluating the potential reductions and costs stems from the availability of data, as mentioned earlier. Consequently, the reductions presented here might be subject to commensurate uncertainties in either direction. Additional information from energy surveys would thus be needed to reduce this uncertainty in both potential reductions of GHG and costs. Note that the majority of the emissions reduced are due to efficiency improvements and thus seem to incur negative costs. The large negative numbers for costs raise questions about the current efficiency levels and the profit maximizing behavior of the firms. This also seems to suggest that further mitigation might be possible here at higher costs and additional research might be needed in this regard. Furthermore, the measures listed above have been selected based on the expectation of cost-effectiveness after a review of literature. This potential, thus, might also be increased by considering other measures discussed in the literature.<sup>142</sup> Lastly, the methodology or the data that are used as a part of arriving at the above numbers is not detailed fully thus precluding a complete analysis of the numbers presented.

### **3.6.3. Petroleum and gas production**

California is home to a large oil and gas industry that produces 250 million barrels of oil and 325 billion cubic feet of gas. Most oil wells are located in the south while a majority of gas fields are in northern California. As per the GHG inventory, in 2004 oil and gas production systems accounted for about 14.3 MMt CO<sub>2</sub>e or 12% of the GHG emissions from the industrial

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<sup>141</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

<sup>142</sup> Worrell, E. and C. Galitsky (2004). Profile of Petroleum Refining Industry in California, Lawrence Berkeley National Laboratory, LBNL Report 55450.

sector.<sup>143</sup> The GHG mitigation measures put forward by CARB in this sector can be categorized as emissions from extraction & processing and from transmission & storage activities.

Emissions during extraction & processing are primarily from combustion of gas in boilers, pumps, generators (mainly CO<sub>2</sub>). The measures proposed towards GHG emission reduction here are primarily geared towards improving the fuel efficiency at various stages. The range for potential reduction from these activities is reported to be 1.5 to 2.5 MMt CO<sub>2</sub>e per year. The capital costs associated with this measure were estimated to be \$350 million and the annual savings were estimated to be \$170 million.

Emissions during transmission and storage, on the other hand, are largely fugitive emissions (mainly CH<sub>4</sub>) and thus are more difficult to quantify. These emissions come from accidental releases of GHG or through venting/ leaks from various components of the production systems such as valves, flanges and so on. The mitigation measures being pursued here are replacements with other technologies and better management practices. These measures largely fall under the US EPA's Natural Gas STAR program for reducing methane emissions. In order to reflect the uncertainties in quantifying the emissions, a range for the potential GHG reduction was given as 0.5 to 1.5 MMt CO<sub>2</sub>e per year. The capital costs associated with this measure were estimated to be 28 million dollars and the annual savings were estimated to be 15 million dollars.

Combining these numbers, the GHG reduction through the above measures in oil & gas production systems was assumed to be 3 MMt CO<sub>2</sub>e per year at about -\$61.67 per tonne of CO<sub>2</sub>. As is also the case for petroleum refining, a major constraint in evaluating this measure is the lack availability of both data on emissions or energy consumption, and of relevant studies. Thus, our best estimate is directly from CARB.

#### **3.6.4. Other materials production**

There may be significant opportunities to reduce emissions from the manufacturing of primary metals, chemicals, pulp & paper, food products, tobacco, electronic instruments, metal durables, textiles, wood products, furniture and plastics. Each of these industries involves combustion of fossil fuels, and more efficient manufacturing processes may be able to build upon the current trend of decreasing carbon intensity in industry. Our estimates for other materials production are currently placeholders until more detailed research can be performed. The total emissions from these processes, as given by the CARB 2004 inventory, are about 11 MMt CO<sub>2</sub>e.<sup>144</sup> We begin with this number and assume that a 10% improvement can be achieved. This yields a very rough estimate of 1.1 MMt CO<sub>2</sub>e of emissions reductions. For these emissions reductions, we are assuming a cost of \$100 per tonne CO<sub>2</sub>e based on our best judgment.

CARB, as a part of the scoping plan report, examined the potential from this sector by means of regulating the efficiency of boilers and internal combustion engines. It was estimated that improving industrial boiler efficiency (through regulations for annual tuning of boilers, installation of oxygen trim systems and a non-condensing economizer) would lead to GHG emissions reduction in the order of 0.5 to 1.5 MMt CO<sub>2</sub>e per year. This measure would cost \$90 million with annualized net savings of \$127 million. Similarly, electrifying stationary internal

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<sup>143</sup> California Energy Commission. (2006). "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004." Retrieved May, 2008, from [www.arb.ca.gov/cc/inventory/doc/doc\\_index.php](http://www.arb.ca.gov/cc/inventory/doc/doc_index.php).

<sup>144</sup> California Air Resources Board (2008). Climate Change Draft Scoping Plan. Sacramento, CA.

combustion engines would lead to reduction in GHGs to the order of 0.1 to 1 MMt CO<sub>2</sub>e per year. This measure was estimated to cost \$51 million with annualized net savings of \$13 million. Thus, the total reduction as per CARB's estimate ranges from 0.6 to 2.5 MMt CO<sub>2</sub>e.

Note that the significant negative cost here again raises questions about the current level of operating efficiencies and the profit maximizing behavior of the firms. However, the methodology or the data for arriving at these numbers is not clear and this measure, thus, is ripe for further investigation.

### **3.6.5. Industrial carbon capture and storage**

Industrial Carbon Capture and Storage (CCS) involves implementing CCS on fossil-burning industrial activities to reduce emissions from industrial processes. In order for this process to be feasible, there must be a low-cost carbon capture process and the possibility of storage.

Two reasonable possibilities exist for storage: (1) as discussed above, in the cement industry it may be possible to sequester CO<sub>2</sub> in newly poured cement, and (2) if industry is located near geologic sequestration locations, emissions can be geologically sequestered. The first possibility is a promising new technology that may develop into an important source of future reductions, but little or no data are currently available on the potential of such technologies. The second possibility may also hold some promise. However, while some industry in California may be located in the proximity of geologic sequestration locations, in general industry is quite dispersed, leaving this option only available for a small percentage of industrial activity. Thus, we believe that industrial CCS emissions reductions are likely to be a very small contribution to total emissions reduction, so we use an estimate of zero emissions reductions for industrial CCS.

This choice is also bolstered by our understanding of the possible cost of industrial CCS. To understand what the cost of the process might look like, we can best compare it to the expected costs of utility electricity generation CCS. Utility CCS schemes primarily are based on the creation of synthesis gas from the combustion emissions. The idea then is that the synthesis gas would include a mostly pure CO<sub>2</sub> stream that could be captured and compressed relatively easily. On the other hand, for industrial processes that involve pure combustion, the resultant gas stream is likely to be mostly nitrogen, which does not currently look economically viable to capture. Thus, it is clear that industrial CCS must be more costly than utility CCS, which our analysis already suggests would be on the higher end of costs in our marginal abatement cost curve, and likely above the AB 32 target emission reduction.

For comparison purposes, we performed an analysis to see what the maximum potential of industrial CCS might be by examining coal emissions from industry. A very high percentage of coal emissions from industry are from the cement industry, so we begin there. We use data from the Portland Cement Association on coal consumption and emissions, and combine these with data on coal consumption and industrial emission from the US Department of Energy's Energy Information Administration (EIA) to find that industrial emissions from coal in California are approximately 5.4 MMt CO<sub>2</sub> per year.<sup>145</sup> Clearly not all of these emissions can be captured and geologically stored. If we assume that 90% of these emissions can be captured and stored, this

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<sup>145</sup> EIA (2005). Annual Energy Outlook 2005. Washington, DC, US Department of Energy.



would imply a potential emission savings of 4.9 MMt CO<sub>2</sub> per year of potential emission savings.

In our literature review, the only estimate we found of the cost of achieving emissions reductions from industrial CCS is from the 2007 McKinsey National Report.<sup>146</sup> The McKinsey report suggests that mid-range new industrial CCS in 2030 would cost \$49 per tonne of CO<sub>2</sub>. For the reasons discussed above, we believe that this estimate is the low side for a 2020 estimate, and thus, we feel comfortable not including industrial CCS in our estimates.

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<sup>146</sup> McKinsey and Company (2007). Reducing U.S. Greenhouse Gas Emissions: How Much and at What Cost? US Greenhouse Gas Abatement Mapping Initiative Executive Report.

### 3.7. Land-use and forestry

Table 23. Summary estimates for land-use and forestry

Measure	Emission Reduction (MMt CO <sub>2</sub> e)	Costs (\$/MTCO <sub>2</sub> e)
Smart Growth	9.9	\$0
Afforestation/ Reforestation	2.0	\$11
Conservation Forest Management	2.4	\$2
Forest Conservation	0.4	\$38

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#### 3.7.1. Smart growth

##### *Background*

Smart growth planning as a tool for emission reduction primarily falls under the umbrella of measures addressing the transportation sector. Unlike other transportation-related measures such as improving vehicle efficiency or changing fuel blends, which reduce the emissions per unit travel, smart growth seeks to reduce emissions by reducing VMT and/ or by encouraging switching to less energy intensive modes of travel. The report from Urban Land Institute (ULI)<sup>147</sup> on this issue emphasizes the importance of this approach while noting that reduction in GHG emissions due to other measures can be offset by the increase in total VMT in the long run. With increasing population, cities have tended to grow outwards thus increasing the sprawl. Consequently, commuting distances have increased leading to higher VMT and higher emissions. Smart growth was proposed as solution for this problem and is basically anti-sprawl development. Smart growth, as defined by the ULI, is development that is environmentally sensitive, economically viable, community-oriented, and sustainable. Smart growth is based on a number of principles, the most important of which include mixing land uses, compact building design, increased housing and travel options and transit oriented development.<sup>148</sup>

In addition to the emissions reductions brought about by lowering the VMT, smart growth could lower energy consumption (and thus GHG emissions) as well by changing the mix of residence types (e.g. more smaller housing), lowering the transmission distances for power and other utilities, increased plant cover and so on. The potential for smart growth planning here (7.1 MMt), however, includes only the reductions due to changes in travel.

<sup>147</sup> Ewing, R., K. Bartholomew, et al. (2007). *Growing Cooler: The Evidence on Urban Development and Climate Change*. Washington, DC, Urban Land Institute.

<sup>148</sup> Note that the definition of Smart Growth itself might not be the same across different entities.

*Emissions reductions and costs*

Different planning agencies that have jurisdiction over different regions have developed land use plans that are based on smart growth principles such as Compact Development, Transit-Oriented Development and so on to different extents. In order to estimate the GHG reductions from smart growth the regions that had plans incorporating smart growth principles were first identified. At the first stage, an agency typically developed a blueprint that is rooted in different smart growth principles. The resulting product was subsequently incorporated into the regional transportation plan. The alternative scenarios were then evaluated using various transportation models to compute metrics (e.g. total VMT, total emissions, etc) corresponding to the baseline<sup>149</sup> and planned scenarios. The GHG reductions from smart growth planning in this project were estimated by contacting individual agencies and summing up the corresponding numbers from various regions. The total was then found to be 7.1 MMt CO<sub>2</sub>e. In cases where the exact number for 2020 was not available, the available estimate was scaled down in order to obtain the approximate reduction in 2020. The following table shows the agency, the population and the VMT in each of the four regions that were included in the above number.<sup>150</sup>

<b>Municipal Planning Organization</b>	<b>Population (millions)</b>	<b>VMT (million miles)</b>	<b>Counties</b>
Southern California Association of Governments (SCAG)	16.5	474.2	Imperial, Los Angeles, Orange, Riverside, San Bernardino, Ventura
Metropolitan Transportation Commission (MTC)	6.9	166.8	Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Sonoma, Solano
San Diego Association of Governments (SANDAG)	2.8	131.9	San Diego
Sacramento Area Council of Governments (SACOG)	1.9	69.7	El Dorado, Placer, Sacramento, Sutter, Yolo, Yuba
Total	28.0	842.6	
CA total	33.9	1075.5	

The total VMT for CA in 2001 was 1075.5 million vehicle miles and these four regions constituted almost 78% of the total VMT in California.<sup>151</sup> Thus, the above number can serve as a reasonable estimate for the reductions from smart growth plans for the whole state. In addition to these four regions, the planning agencies for Bakersfield, Fresno, Monterey, Stockton and Modesto were also contacted for any smart growth initiatives or details on efforts towards AB

<sup>149</sup> Baseline here usually corresponds to the scenario where an older plan is implemented in place of the smart growth based plan.

<sup>150</sup> Weidner, T. and S. Seskin (2001). California Smart Growth Energy Savings MPO Survey Findings, Parsons Brinckerhoff Report P600-01-021F, California Energy Commission. Sacramento, CA.

<sup>151</sup> Ibid.

32.<sup>152</sup> Of these only the Fresno region planning agency (FRESNOCOG) has conducted a scenario evaluation exercise and has estimates for GHG reductions. The amount, however, is quite low when compared to the reductions projected in the four major regions. The rest of the regions do not have a smart growth oriented blueprint ready yet. However, the planning agency in a number of these regions does have a planning effort in the pipeline.

An important caveat that needs to be mentioned while interpreting the numbers for the smart growth is the high degree of uncertainty that stems from various steps in the procedure. Factors contributing to this include inherent complexities in predicting how the development will unfold under various policies, inaccuracies/uncertainties in travel modeling, ability of current models to account for land use changes, limited modeling of non-motorized & short trips and also quantification of emissions from running vehicles given the large number of variables involved (e.g. travel speeds, type/ age of vehicles, fuels, etc). In addition to the fact that only four regions were accounted for, the modeling constraints, in particular, would lead to underestimation of the true potential of smart growth to reduce emissions.

It should also be noted that this approach for determining the potential for smart growth as an emission reduction measure does not give the ‘true’ potential since it might always theoretically be possible to reduce the emissions by altering the agencies’ plans. The approach, however, does give the most feasible potential for reduction of GHG through smart growth. Emission reduction is only one of the positive outcomes of smart growth planning and thus the planning agencies might strive to balance various objectives through their plans. Note that the formulation of some of these plans precedes AB-32 and as such GHG emission reduction was not the only objective.

The above discussion includes only the reduction in GHG emissions due to smart growth planning. In addition to this there are a number of other transportation related measures such as Intelligent Transportation Systems (ITS) and operational efficiency improvements, changing cement composition for construction of infrastructure, fleet greening, etc. The savings from these measures as reported in the CAT report (2007) is 2.82 MMt CO<sub>2</sub>e. Thus, the total reduction in emissions including smart growth is 9.88 MMt CO<sub>2</sub>e.

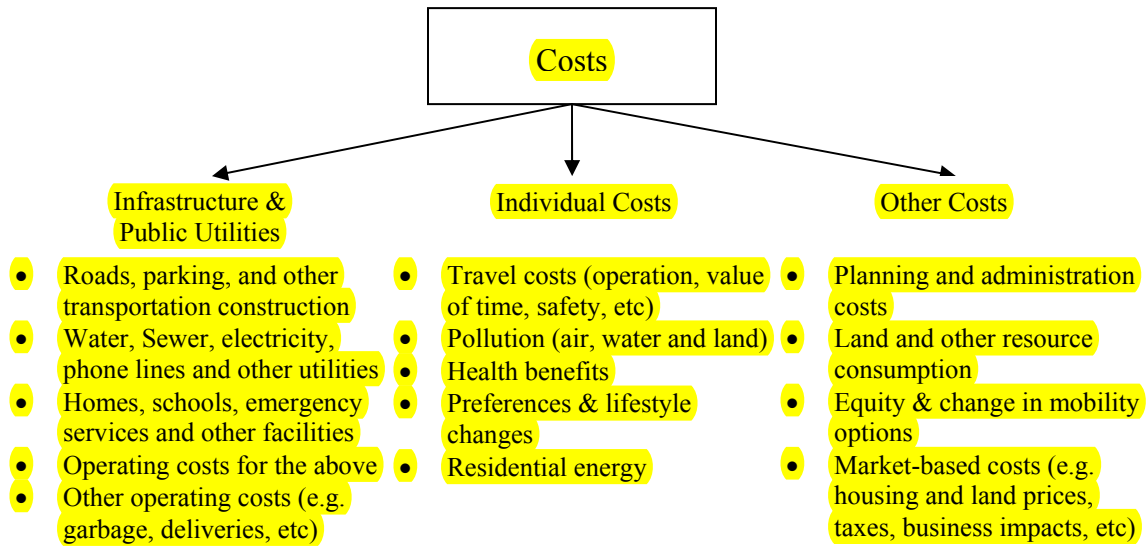
Smart growth planning leads to a significant number of changes. Given the complexities involved, a comprehensive evaluation of the complete social costs, which could be positive or negative (i.e. benefits) costs, associated with smart growth planning is quite a challenging exercise. This is especially so given the difficulty associated with quantifying intangible changes that occur as a result of implementing the plans. A cost analysis of smart growth would involve a comparison of the various costs that are incurred in the preferred and baseline scenarios. Burchell et al.<sup>153</sup> constitutes the most comprehensive of such studies where the potential savings from smart growth planning are estimated and considerable reduction in measurable costs was reported.

A review of the literature in this area was done and the following taxonomy of costs was developed for evaluating the costs corresponding to each scenario.

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<sup>152</sup> These constitute all the regions whose annual VMT was over 10 million vehicle miles in 2001.

<sup>153</sup> Burchell, R., G. Lowenstein, et al. (2002). Costs of Sprawl - 2000. Washington, DC, Transportation Research Board.



Note that this might not a comprehensive list and that there might be a number of costs that are not envisioned because of the uncertainty regarding the changes that might materialize upon implementation. Furthermore, the magnitude of some of these costs might also be difficult to measure and consequently the estimates for total cost would be quite uncertain. This is particularly true for lifestyle and preference changes which would involve valuation of the willingness to pay/ accept for different individuals in relation to the change. The evaluation of these intangible costs can be complex and there is not much primary research in this area. The other costs that are difficult to evaluate are the secondary economic costs which are brought about by implementing the preferred scenario. Examples include increase in land prices, impact on businesses and how these changes will impact overall consumer surplus.

A number of studies, however, found that significant savings can be achieved in terms of infrastructure costs, travel costs, energy costs and other costs that can be quantified. SACOG, for instance, reports \$16 billion savings in terms of the infrastructure costs by 2050. Similarly, SANDAG estimates that up to 48 million gallons of gasoline could be saved during the year 2030 on adoption of the plan. In addition to these, resources such as crop land and forest cover could also be saved since lower acreage of lands would need to be converted to urban lands. A number of other studies too have found significant savings in terms of a number of costs.<sup>154,155,156,157</sup>

<sup>154</sup> Ewing, R., K. Bartholomew, et al. (2007). *Growing Cooler: The Evidence on Urban Development and Climate Change*. Washington, DC, Urban Land Institute.

<sup>155</sup> Weidner, T. and S. Seskin (2001). *California Smart Growth Energy Savings MPO Survey Findings*, Parsons Brinckerhoff Report P600-01-021F, California Energy Commission. Sacramento, CA.

<sup>156</sup> Burer, M. J., D. Goldstein, et al. (2004). *Location Efficiency as the Missing Piece of the Energy Puzzle: How Smart Growth Can Unlock Trillion Dollar Cost Savings*. ACEEE Summer Study on Energy Efficiency in Buildings, Asilomar, CA, American Council for an Energy-Efficient Economy.

<sup>157</sup> Rong, F. (2006). *Impact of Urban Sprawl on US Residential Energy Use*. PhD Dissertation, School of Public Policy, University of Maryland. College Park, MD.

However, in light of the gaps discussed above, a firm conclusion about the exact cost (per tonne of CO<sub>2</sub>e) of this measure for GHG reduction is difficult to draw. The bulk of evidence from the literature seems to suggest that cost is very likely to be negative though.

### **3.7.2. Afforestation/reforestation**

#### *Background*

This strategy involves planting trees on suitable areas that are not forested and thus offset GHG emissions by sequestering carbon through production of fiber in trees. The CAT report<sup>158</sup> analyzed three initiatives that address implementation of the afforestation/ reforestation strategy:

- a) The California Forest Improvement Program (CFIP) that is administered by CALFIRE
- b) Establishment of a cap and trade program that permits the use of forest carbon sequestration offsets through participation of CALFIRE in the Governor's Market Solution Committee.
- c) Afforestation/ Reforestation of the state land holdings.

#### *Emissions reductions and costs*

The cumulative land planted under the above three approaches till 2020 amounts to 43,000 acres sequestering at least 12.5 MMt CO<sub>2</sub> by 2020. The annual sequestration during 2020 is 1.98 MMt at a cost of \$21 million (i.e., at a cost of \$10.61 per tonne).<sup>159</sup> It should be observed here that the potential carbon sequestration is estimated only for the three initiatives. The estimates for total amount of land available for this strategy is 7.1 million acres (CDF estimate) and thus, higher amounts of carbon might be mitigated through consideration of other approaches and initiatives. Additionally, as mentioned in the CAT report (2007) significant uncertainties arise here in addition to uncertainties in the input data, due to consideration of carbon markets that are yet to be formed.

### **3.7.3. Conservation forest management**

#### *Background*

This strategy involves a number of forest management practices that change the composition, structure or arrangement of a standing forest. Examples of such activities include thinning, provision of buffer strips, inter-planting of trees, and removal of competing vegetation.

The approaches analyzed under this strategy include augmenting CFIP funding for the forest management cost share activities (approach 1), continued encouragement of carbon market development (approach 2), adoption of additional voluntary tariffs by the utilities (approach 3), incentives to maintain or expand acres under forest management (approach 4) and lastly, documenting carbon sequestered through past projects (approach 5).

#### *Emissions reductions and costs*

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<sup>158</sup> Climate Action Team (2007). Attachment B to Climate Action Team Report: Climate Strategy Updates. Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report, Public Review Draft.

<sup>159</sup> A common thread among forestry-based efforts is that they also lead to additional benefits to the society such as improved water and air quality, wildlife habitat diversity, and recreational and job opportunities.

The CAT report (2007) notes that conservation forest management activities other than increasing buffer zone do not seem to increase the forest stocks of carbon. Thus, carbon benefits were estimated only for increasing the riparian buffer zone by an additional 200 feet. The amount of CO<sub>2</sub> sequestered through approaches 1, 2, 3 and 4 was estimated to be 0.26 MMt per year<sup>160</sup> and the number for approach 5 was estimated to be 2.09 MMt. The cost of implementing 1, 2, 3 and 4 was computed to be \$19.67 per tonne. However, approach 5 is a result of past changes and no present costs were assumed to be accrued. Thus, this strategy as a whole can help mitigate 2.35 MMt of CO<sub>2</sub> at an average cost of \$2.2 per tonne. The CAT report once again acknowledges the uncertainty issues with unformed carbon markets and uncertainties in input data.

### **3.7.4. Forest conservation**

#### *Background*

Conversion of forestlands and woodlands that has been happening in California continues to release sequestered carbon back into the atmosphere and also reduces the opportunities for further sequestration on these lands. Carbon emissions can thus be reduced or avoided by fewer forest conversions to other land uses by retiring forestlands through easements and other interests. The implementation approaches geared towards this strategy include the following: Proposition 40/50 purchases of woodland and forestland in 2005 and 2006 and Proposition 80 purchases to conserve forestland and oak woodland habitats. A total 84,000 acres of forestland and woodland were conserved under the first approach at a cost of \$54 million. Proposition 84 provides for \$185 million for purchases that can improve sequestration in forestlands and oak woodlands.

#### *Emissions reductions and costs*

The annualized amount of CO<sub>2</sub> sequestered from this strategy was computed to be 0.4 MMt per year.<sup>161</sup> The cost of approach 1, since it was in the past, was assumed to be zero. The cost of implementing proposition 84 is assumed to be the total cost of the program. Thus, the emission reduction from this strategy will cost \$37.5 per tonne of CO<sub>2</sub> on average.

The projections of conversion of forestland and woodland by FRAP are, however, much higher than the ones covered under the above two approaches, which work with a target or under a fixed budget. Thus, there might be additional opportunities for CO<sub>2</sub> reduction through design of new programs. Additionally, as noted in the report, difficulty in purchasing precisely the type of lands or vegetation leads to uncertainties. This is further exacerbated by uncertainties in methodology of computing emissions and other natural uncertainties.

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<sup>160</sup> An additional 0.1 MMt CO<sub>2</sub> can be reduced through lengthening of rotation period at a higher cost.

<sup>161</sup> A majority of the sequestration here occurs near the time of purchase and the annualized estimate was obtained by dividing the cumulative reduction by the number of years.

