Section 4.8
Greenhouse Gas Emissions

DRAFT

California Environmental Protection Agency
Air Resources Board

EXPANDED LIST OF EARLY ACTION MEASURES TO REDUCE GREENHOUSE GAS EMISSIONS IN CALIFORNIA RECOMMENDED FOR BOARD CONSIDERATION

Lyell Glacier, Yosemite National Park, California, USA circa 1903 (upper) and 2003 (lower)

SEPTEMBER 2007

TABLE OF CONTENTS

Comments on this report or its supporting appendices should be submitted to Michael Robert at (916) 327-0604, mrobert@arb.ca.gov and Dr. Tao Huai at (916) 324-2981, thuai@arb.ca.gov by September 24th, 2007.

The ARB staff is recommending that the Board expand the list of early action measures being pursued to reduce greenhouse gas emissions from 37 to 44 measures. Of these measures staff believes 9 merit consideration to be placed on the list of discrete early actions as defined by the California Global Warming Solutions Act of 2006 (AB 32), increasing the size of the current list of 3 by 6 items. Cumulatively, these 44 measures have the potential to deliver greenhouse gas emission reductions on the order of at least 42 million metric tons of CO_2-equivalents ($MMTCO_2E$) or a quarter of the 2020 emission reductions needed to meet AB 32 goal. Existing ARB regulations will contribute approximately an additional 30 $MMTCO_2E$ reductions. The Climate Action Team has also identified measures (external to the ARB) that account for a cumulative reduction of approximately 68 $MMTCO_2E$. The remaining reductions to meet the 2020 target will be identified by the Scoping Plan due in late 2008. These additional early action recommendations will be presented at a September 17, 2007 public workshop and following consideration of public input will be brought before the Board at its October 25-26, 2007 hearing.

EXECUTIVE SUMMARY

In June 2007 the Air Resources Board (ARB) directed staff to pursue 37 early actions for reducing greenhouse gas (GHG) emissions under the California Global Warming Solutions Act of 2006 (AB 32). The broad spectrum of strategies to be developed – including a Low Carbon Fuel Standard, regulations for refrigerants with high global warming potentials, guidance and protocols for local governments to facilitate GHG reductions, and green ports – reflects that the serious threat of climate change requires action as soon as possible. Three of these 37 identified strategies were also identified as discrete early action measures. These are measures that could be fully adopted as regulations and made effective no later than January 1, 2010, the date established by the Health and Safety Code (HSC) Section 38560.5(b) that requires ARB to adopt discrete early actions.

In addition to approving the 37 GHG reduction strategies, the Board directed staff to further evaluate early action recommendations made at the June 2007 meeting by the AB 32 Environmental Justice Advisory Committee (EJAC), the California Air Pollution Control Officers Association (CAPCOA), and the South Coast Air Quality Management District (SCAQMD), and to report back to the Board within six months. The general sentiment of the Board suggested a desire to try to pursue greater GHG emissions reductions in California in the near-term. This revised early actions report provides staff's analyses of additional emission reduction strategies, and provides recommendations to significantly expand the list of early actions as well as discrete early action measures as identified by HSC Section 38560.5(a).

Since the June 2007 Board hearing, ARB staff has evaluated all 48 recommendations submitted by the EJAC, CAPCOA, and SCAQMD, as well as several other stakeholder suggestions and several internally-generated staff ideas. Each of these measures has been carefully considered with respect to potential emissions reductions, technological feasibility, estimated costs, and economic impacts. This document reports staff's findings and makes further recommendations for a revised list of early actions and, specifically, discrete early action measures (See insert in next page for definitions). The report also provides much greater detail on the evaluation of measures that staff has conducted since the previous April 2007 early actions report[1] was released.

Based on its additional analysis, ARB staff is recommending the expansion of the early action list to a total of 44 measures. The additions to the list of the ARB's commitments also triple the number of measures that would be pursued on an accelerated timeline that meets the AB 32 timeframe for discrete early actions.

In total, as shown in Figure ES-1, the 44 recommended early actions have the potential to reduce GHG emissions by at least 42 million metric tons of carbon dioxide (CO_2) equivalent ($MMTCO_2E$) emissions by 2020, representing about 25% of the estimated reductions needed by 2020. ARB staff is working on 1990 and 2020 GHG emission inventories in order to refine the projected reductions needed by 2020 and expects to present its recommendations to the Board by the end of 2007. The 2020 target reductions are currently estimated to be 174 $MMTCO_2E$.

Efforts to develop several of the strategies are already underway with workshops planned for fall 2007 and early 2008. Further, the Climate Action Team (CAT) member agencies[2] are also moving forward with early actions with a targeted reduction of 68 $MMTCO_2E$ by 2020[3]. Both the ARB and CAT emission reduction projections are best estimates that are subject to revision as additional information on individual measures becomes available. The ARB staff will report on the early actions progress to its Board every six months. The CAT will also periodically update its efforts and progress on a similar schedule.

A list of all 44 early actions is presented in Table 1, with recommended additions as well as the discrete early action measures identified. In addition, the year and quarter in which the ARB Board hearing is anticipated is also indicated. Inclusion of a strategy, regardless of classification or whether it can be implemented before or after the January 1, 2010 enforceability date for discrete early action measures, represents a commitment by the Board to pursue and – for those strategies that meet all legal and technical requirements – bring the measure to the Board on the timeframe illustrated in the table.

[1] Available at www.arb.ca.gov/cc/042307workshop/early_action_report.pdf.
[2] Includes the California Environmental Protection Agency, the Business, Transportation and Housing Agency, the Department of Food and Agriculture, the Resources Agency, the Air Resources Board, the Energy Commission, and the Public Utilities Commission.
[3] Those actions are described by the CAT in its companion report on early actions which can be found at www.climatechange.ca.gov/climate_action_team/reports/2007-04-20_CAT_REPORT.

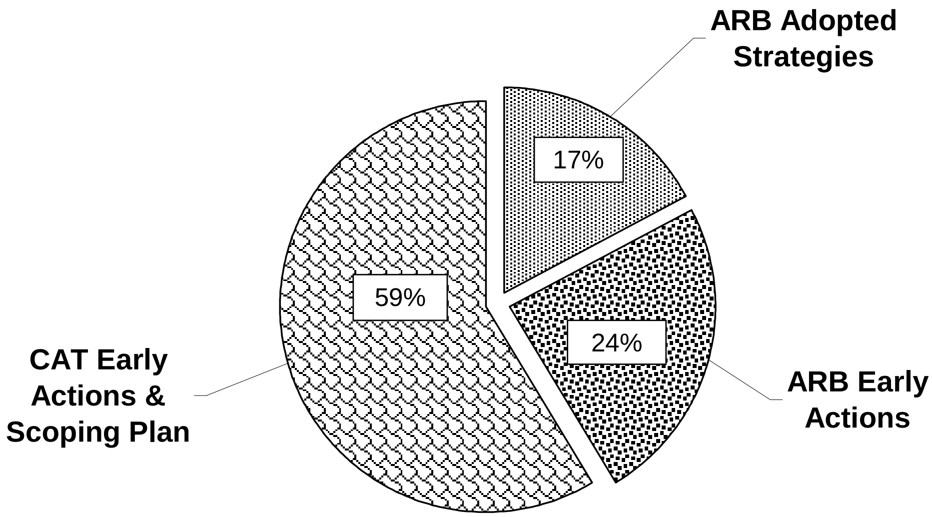


Figure ES-1. 2020 ARB GHG Reduction Estimates by
Different Elements of the State's Climate Protection Action Plan.

BACKGROUND

The California Global Warming Solutions Act of 2006 (AB 32) creates a comprehensive, multi-year program to reduce GHG emissions in California, with the overall goal of restoring emissions to 1990 levels by the year 2020 (see Figure 1). AB 32 recognizes that such an ambitious effort requires careful planning and a comprehensive strategy. By January 1, 2009 the Board must design and adopt an overall Scoping Plan to identify how GHG emissions can be reduced back to 1990 levels by 2020. The Board has until January 1, 2011 to adopt the necessary regulations to implement that plan. Implementation begins no later than January 1, 2012 and the emissions reduction target is to be achieved by January 1, 2020. AB 32 also directs the Board to make recommendations on how to best achieve further reductions beyond 2020.

Discrete Early Action – Greenhouse gas reduction measure underway or to be initiated by ARB that meets the AB 32 legal definition as identified by the Health and Safety Code Section 38560.5. Discrete early actions are regulations to reduce greenhouse gas emissions adopted by the Board and enforceable by January 1, 2010.

Early Action – Greenhouse gas reduction measures underway or to be initiated by ARB in the 2007 – 2012 timeframe. These measures may be regulatory or non-regulatory in nature.

In April of 2007 ARB staff released a report entitled 'Proposed Early Actions to Mitigate Climate Change in California.' In that report staff proposed 37 early actions to reduce GHG emissions in California with a cumulative estimate in the range of 33-46 $MMTCO_2E$ by 2020. Existing ARB regulations contributing an additional 30+ $MMTCO_2E$ (principally the AB 1493 regulations on vehicle GHG emissions) were also discussed. Thus, ARB committed to pursue strategies with the potential to yield over 60 $MMTCO_2E$ by 2020, representing an important down payment towards the estimated 2020 reduction target. In its April 2007 report staff recommended that three of these strategies be developed on a schedule that met the AB 32 legal requirement for discrete early action measures – the Low Carbon Fuel Standard (LCFS), reduction of refrigerant losses from motor vehicle air conditioning maintenance, and increased methane capture from landfills.

At its June hearing the Board adopted a resolution which listed three discrete early action measures recommended by the staff and also committed ARB to pursue a total of 37 early actions. The Board also directed the staff to further evaluate recommendations for early actions made by the EJAC, CAPCOA, and the SCAQMD, and to report back to the Board within six months. The general sentiment of the Board suggested a desire to try to accomplish greater GHG emissions reductions in California in the near-term. The staff has completed these additional analyses requested by the Board and staff's conclusions and recommendations form the basis of this report. The updated recommendations documented herein will be presented at a September 17, 2007 public workshop at ARB headquarters in Sacramento, and following additional consideration of public input by the staff will be considered by the Board at its October 25-26, 2007 hearing.

Figure 1. Comprehensive Multiyear Program Established by AB 32

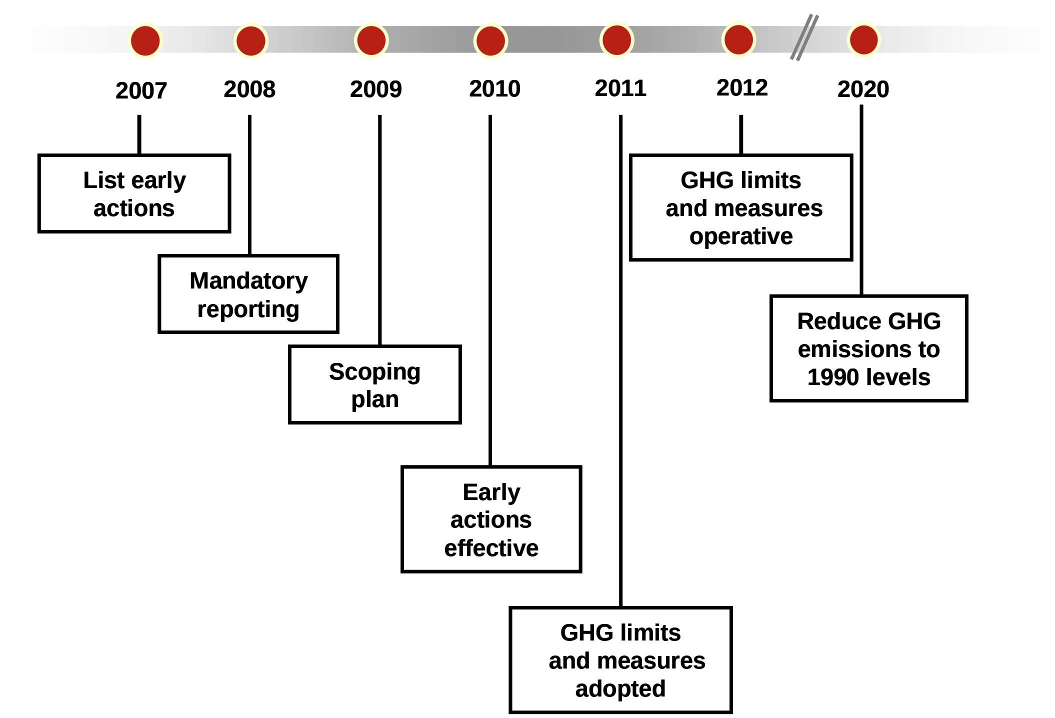


TABLE 1. GHG REDUCTION MEASURES UNDERWAY OR TO BE INITIATED BY ARB IN THE 2007-2012 PERIOD

EA ID	SECTOR	STRATEGY NAME	ARB BOARD HEARING DATE[1]																							
			2007				2008				2009				2010				2011				2012			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	Fuels	Above ground storage tanks[2]		■																						
2	Transportation	Diesel - Offroad equipment (non-agricultural)[2]			■																					
3	Forestry	Forestry protocol endorsement[2]				■																				
4	Transportation	Diesel - Port trucks[2]				■																				
5	Transportation	Diesel - Vessel main engine fuel specifications[2]				■																				
6	Transportation	Diesel - Commerical harbor craft[2]				■																				
7	Transportation	Green ports					■																			
8	Agriculture	Manure management (methane digester protocol)[2]							■																	
9	Education	Local government GHG reduction guidance / protocols[2]							■																	
10	Education	Business GHG reduction guidance / protocols[2]							■																	
11	Energy Efficiency	Cool communities program[2]							■																	
12	Commercial	Reduction of high GWP GHGs used in consumer products[3]								■																
13	Commercial	Reduction of PFCs from semiconductor industry								■																
14	Transportation	SmartWay truck efficiency								■																
15	Transportation	Low Carbon Fuel Standard (LCFS)								■																
16	Transportation	Reduction of HFC-134a from DIY MVAC servicing								■																
17	Waste	Improved landfill gas capture								■																
18	Fuels	Gasoline dispenser hose replacement[2]								■																
19	Fuels	Portable outboard marine tanks[2]								■																
20	Transportation	Standards for off-cycle driving conditions[2]								■																
21	Transportation	Diesel - Privately owned on-road trucks[2]								■																
22	Transportation	Anti-Idling enforcement[2,3]								■																
23	Commercial	SF_6 reductions from the non-electric sector[3]									■															
24	Transportation	Tire inflation program									■															
25	Transportation	Cool automobile paints										■														
26	Cement	Cement (A): Blended cements[3]										■														
27	Cement	Cement (B): Energy efficiency of California cement facilities[3]																■								
28	Transportation	Ban of HFC release from MVAC service / dismantling												■												
29	Transportation	Diesel - offroad equipment (agricultural)[2]												■												
30	Transportation	Add AC leak tightness test and repair to Smog Check													■											
31	Agriculture	Collaborative research on GHG reductions from nitrogen land application[3]																■								
32	Commercial	Specifications for commercial refrigeration																■								
33	Oil and Gas	Reduction of venting / leaks from oil and gas systems																■								
34	Transportation	Requirement of low-GWP GHGs for new MVACs[4]																■								■
35	Transportation	Hybridization of medium and heavy-duty diesel vehicles																	■							
36	Electricity	Reduction of SF_6 in electricity generation																		■						
37	Commercial	High GWP refrigerant tracking, reporting, and recovery program[3]																				■				
38	Commercial	Foam recovery / destruction program																				■				
39	Fire Suppression	Alternative suppressants in fire protection systems																				■				
40	Transportation	Strengthen light-duty vehicle standards																								■
41	Transportation	Truck stop electrification with incentives for truckers																								
42	Transportation	Diesel - Vessel speed reductions[2,5]																								
43	Transportation	Transportation refrigeration - electric standby[2,5]																								
44	Agriculture	Electrification of stationary agricultural engines[5]																								

CUTOFF ADOPTION DATE FOR 01/01/2010 ENFORCEABILITY

= these items are expected to meet the AB 32 definition of discrete early actions in that they directly address GHG emission, are regulatory, and are enforceable by January 1, 2010

[1] Add 9-12 months to Board adoption date to determine the approximate date of Office of Administrative Law (OAL) approval, thereby making a regulation that the Board has adopted legally enforceable.

[2] There is a reasonable expectation that these measures will yield some reductions in emissions impacting climate (e.g., diesel particulate matter, hydrocarbons). However, they are not listed as discrete early actions because they do not directly address greenhouse gases for which the science is most robust (e.g., CO_2, SF_6, N_2O, CH_4, HFC, PFC), are non-regulatory, or are not enforceable by January 1, 2010. Some are regulations recently adopted by the Board.

[3] These are additional early actions that were not on the list approved by the Board at its June 2007 hearing.

[4] New requirements for HDVs and other classes not included in AB 1493 to be adopted in 2010. Additional requirements for LDVs to be adopted in conjuction with Pavley II (EA ID 40).

[5] Board hearing is not required or indicated - these measures may be ongiong voluntary efforts or under evaluation by staff with insufficient data to justify setting a Board hearing date at this time.

The ARB is one of many state agencies pursuing early actions. The CAT has identified and is refining additional GHG reduction strategies that can be accomplished or initiated in the 2007-2009 period. The CAT process continues to evolve and grow and its early actions will be indispensable for meeting the 2020 target.

The ARB is also in the process of developing a comprehensive Scoping Plan, due in late 2008, which will outline a multifaceted approach to meeting the 2020 emissions reduction target defined in AB 32. The Scoping Plan will evaluate opportunities for sector-specific reductions, integrate synergistically all ARB and CAT early actions and additional GHG reduction measures by both entities, identify additional measures to be pursued as regulations, and define the role of any potential market mechanisms such as a cap-and-trade program. The analyses of many potential GHG emission reduction strategies that are not recommended as early actions are currently underway and will continue as part of the Scoping Plan development. Recommendations regarding the form of these additional GHG reduction measures (e.g., regulatory, non-regulatory, market-based) will be included in the Scoping Plan.

AB 32 requires that all GHG reduction regulations adopted and implemented by the Board be technologically feasible and cost-effective. The law also requires that GHG measures be structured to prevent negative impacts on emissions of criteria pollutants (e.g., hydrocarbons, particulate matter) and to avoid any disproportionate socioeconomic effects (among other criteria). These are critical considerations for each of the recommended early actions. Staff must address these factors fully as detailed proposals are developed. While staff has advanced its understanding with respect to key requirements that must be addressed for most of the proposed strategies, the analyses have not progressed to the point where all impacts (e.g., technical feasibility, cost-effectiveness) can be defined conclusively at this time. Staff plans to develop this information for each of the early actions brought before the Board. If additional information or analysis reveals that a particular measure cannot meet one or more of these requirements, it will not be put into effect. The actual design or features of each measure will be crafted through an open public process that includes interaction with interested stakeholders through various means including workshops.

CONSIDERATION OF STAKEHOLDER INPUT

Sources of Additional Strategies

As directed by the Board, ARB staff further evaluated early action recommendations from the EJAC, CAPCOA, and SCAQMD as presented at the June 2007 Board Meeting. The original submissions from these entities are included in Appendix A to this report. A brief summary of recommendations from these three sources is as follows:

- The EJAC submitted 34 recommendations for early actions. Of these, 21 were approved by the Board at its June 2007 hearing. Thirteen strategies were not on the list approved by the Board at its June hearing. These are evaluated in Appendix B.

- The CAPCOA submitted five broad suggestions regarding early actions. These and a sixth suggestion are also addressed in the strategy evaluations presented in Appendix B.

- The SCAQMD submitted eight suggestions pertaining to early actions, each of which was further evaluated by ARB staff as documented in Appendix B.

In addition to the items from these three sources, ARB staff has also evaluated additional potential early actions since the June 2007 Board meeting. These measures were either stakeholder suggestions or were items generated internally. There were also several measures approved by the Board at its June 2007 hearing that have direct climate benefits but were not addressed via the EJAC, CAPCOA, SCAQMD, or additional stakeholder suggestions summarized above that are further evaluated in this report. A list of all 63 items considered from these various sources may be found in Table 2 of this document. The results of the staff analysis for each of the strategies evaluated are included in Appendices B and C as indicated in the 'Summary Number' column of Table 2. For those items in Table 2 that are included in the list of previously approved or newly recommended early actions in Table 1, their Early Action ID number from Table 1 is also provided as a cross-reference.

There were several early actions approved by the Board at its June 2007 hearing which were not evaluated further by the ARB (as the rationale for them was documented in the April 2007 report). These include the three discrete early action measures – specifically the LCFS, reduction of refrigerant losses from motor vehicle air conditioning maintenance, and increased methane capture from landfills – currently approved by the Board. Additionally, some air pollution control measures that have been approved by the Board with potential GHG reductions or other climate co-benefits (e.g., diesel control measures and hydrocarbon emission standards) have not been further evaluated by staff as their primary rationale was already established.

Staff Analysis of Strategies

Based on the direction from the Board, significant staff effort was expended to increase the depth and breadth of the analysis afforded to the strategies suggested by stakeholders. For each candidate early action measure analyzed, staff's recommendation concerning identification as an early action was based on a consideration of potential emissions reductions, estimated costs and economic impacts, the impacted sectors / entities, technological feasibility, and any additional information available. Completion of a full analysis for each of these factors was the goal for each strategy evaluated. However, as a comprehensive assessment will take at least several months for many strategies, much of the desired information is very preliminary or not currently available for a number of measures. Each staff evaluation sought to address:

TABLE 2. GHG REDUCTION STRATEGIES FURTHER EVALUATED BY THE ARB

SUMMARY NUMBER	TBL 1 EA ID	SOURCE	SECTOR	STRATEGY DESCRIPTION	DISPOSITION
NA	17	EJAC	Waste	Landfill methane gas recapture	No Change in Classification
Appendix B01	--	CAPCOA	Government	CAPCOA recommendations	Further Evaluation Required
				1. Prioritize SIP reductions to maximize GHG reductions	
				2. Local rules / potential statewide measures to ID early actions	
				3. Existing permit programs for significant stationary sources	
				4. Develop guidance on review and mitigation of GHGs under CEQA	
				5. Local air district coordinated voluntary programs	
Appendix B02	37	EJAC	Transportation	Refrigerant tracking, reporting and recovery program	Add as an EA
Appendix B03	8	EJAC	Agriculture	Manure digester protocol for calculating greenhouse gas mitigation	No Change in Classification
Appendix B04	33	EJAC	Oil and Gas	Reduce methane venting/leaks from oil and gas systems	No Change in Classification
		EJAC	Oil and Gas	Recycling of waste gases at oil production sites	
		EJAC	Oil and Gas	Eliminate methane exemptions granted to oil production sites	
		EJAC	Oil and Gas	Energy efficiency measures at oil production sites	
Appendix B05	14	EJAC STAKEHOLDER	Transportation	SmartWay truck efficiency	Re-classify as a Discrete EA Measure
Appendix B06	25	EJAC	Transportation	Cool paints for automobiles	No Change in Classification
Appendix B07	7	EJAC/SCAQMD	Commercial	Green ports	Re-classify as a Discrete EA Measure
		EJAC	Commercial	Shoreside generators / electrical hookup	
		SCAQMD	Transportation	Auxiliary ship engine cold ironing	
Appendix B08	43	EJAC	Transportation	Transport refrigeration units, electric standby	No Change in Classification
Appendix B09	41	EJAC	Transportation	Truck stop electrification with incentives for truckers	No Change in Classification
Appendix B10	24	EJAC	Transportation	Tire pressure program	Re-classify as a Discrete EA Measure
Appendix B11	34	EJAC	Transportation	Requirement of low-GWP GHGs for new MACS	No Change in Classification
Appendix B12	30	EJAC	Transportation	Addition of AC leak test and repair requirements to Smog Check	No Change in Classification
Appendix B13	--	EJAC	Cement	WAFFLEMAT Systems	Evaluating for Scoping Plan
Appendix B14	--	EJAC	Commercial	Green ship incentive program	Evaluating for Scoping Plan
Appendix B15	--	EJAC	Commercial	Anti-idling requirement for cargo handling equipment at ports	Evaluating for Scoping Plan
Appendix B16	--	EJAC	Transportation	Electrification of airport ground support equipment	Evaluating for Scoping Plan
Appendix B17	--	EJAC	Commercial	Electrification of construction equipment at urban sites	Addressed via recently adopted regulation
Appendix B18	35	EJAC	Transportation	Hybridization of medium and heavy-duty vehicles	No Change in Classification
Appendix B19	25	STAKEHOLDER	Cement	Cement (A): Energy efficiency of California cement facilities	Add as an EA
		EJAC		Relatively inexpensive energy savings measures with short pay back times for cement industry	
	--		Cement	Low carbon fuels for cement production	
Appendix B20	26	EJAC	Cement	Cement (B): Blended cements	Add as an EA
Appendix B21	--	EJAC	Oil and Gas	Relatively inexpensive energy savings measures with short pay back times for fossil fuel power plants built prior to 1980	Evaluating for Scoping Plan

TABLE 2. GHG REDUCTION STRATEGIES FURTHER EVALUATED BY THE ARB (continued)

SUMMARY NUMBER	TBL 1 EA ID	SOURCE	SECTOR	STRATEGY DESCRIPTION	DISPOSITION
Appendix B22	--	EJAC	Oil and Gas	Identify and implement energy efficiency measures at refiners that include, but are not limited to, conducting an energy audit	Evaluating for Scoping Plan
		EJAC	Oil and Gas	Recycle waste gases at refineries	
		EJAC	Oil and Gas	Energy efficiency measures at refineries	
Appendix B23	--	EJAC	Commercial	Accelerate the replacement of cargo handling equipment at ports	Evaluating for Scoping Plan
Appendix B24	--	EJAC	Agriculture	Evaluate enclosed dairy barns as an additional strategy for the capture and combustion of methane emissions at dairies	Evaluating for Scoping Plan
Appendix B25	--	EJAC	Commercial	Composting – adopt South Coast and San Joaquin rules statewide	Evaluating for Scoping Plan
Appendix B26	--	EJAC	Electricity	Phase out pre-1980 power plants generating at least 100 MW and provide incentives to replace them with clean energy	Evaluating for Scoping Plan
Appendix B27	--	EJAC	Electricity	Prohibit fuel oil burning in pre-1980 power plants generating at least 100 MW	Evaluating for Scoping Plan
Appendix B28	--	EJAC	Oil and Gas	Refinery methane emissions	Evaluating for Scoping Plan
Appendix B29	32	CAPCOA	Commercial	Specifications for commercial refrigeration	No Change in Classification
Appendix B30	--	SCAQMD	Transportation	Accelerate introduction and deployment of light-duty vehicle (passenger) hybrid technology	Evaluating for Scoping Plan
Appendix B31	--	SCAQMD	Oil and Gas	Natural Gas requirement of 1360 Wobbe Index	Further Evaluation Required
Appendix B32	11	SCAQMD	Energy Efficiency	Cool communities program	No Change in Classification
Appendix B33	40	SCAQMD	Transportation	Strengthen light-duty vehcile standards	No Change in Classification
Appendix B34	--	SCAQMD	Transportation	Off Highway Recreational Vehicle (OHRV) evaporative emissions control	Further Evaluation Required
Appendix B35	--	SCAQMD	Transportation	Determination of evaporative emissions from Pleasure Craft	Further Evaluation Required
Appendix B36	42	ARB	Transportation	Vessel speed reduction	No Change in Classification
Appendix B37	22	STAKEHOLDER	Transportation	Anti-Idling enforcement	Add as an EA
Appendix B38	23	ARB	Commercial	SF_6 reductions from the non-electric sector	Add as a Discrete EA Measure
Appendix B39	12	ARB	Commercial	Reduction of high GWP GHGs used in consumer products	Add as a Discrete EA Measure
Appendix B40	31	ARB	Agriculture	Collaborative research to understand how to reduce GHG emissions from nitrogen land application	Add as an EA
Appendix C01	44	ARB EA REPORT	Agriculture	Stationary agricultural engine electrification	No Change in Classification
Appendix C02	13	ARB EA REPORT	Commercial	Reduction of perfluorocarbons (PFCs) from the semiconductor industry	Re-classify as a Discrete EA Measure
Appendix C03	38	ARB EA REPORT	Commercial	Foam recovery / destruction program	No Change in Classification
Appendix C04	9	ARB EA REPORT	Government	Guidance and protocols for local governments to facilitate GHG emission reductions	No Change in Classification
Appendix C05	10	ARB EA REPORT	Business	Guidance/protocols for businesses to facilitate GHG emission reductions	No Change in Classification
Appendix C06	36	ARB EA REPORT	Commercial	Reduce sulfur hexafluoride (SF6) from electrical generation	No Change in Classification
Appendix C07	39	ARB EA REPORT	Commercial	Alternative suppressants in fire protection systems	No Change in Classification
Appendix C08	3	ARB EA REPORT	Forestry	Forestry protocol endorsement	No Change in Classification
Appendix C09	28	ARB EA REPORT	Transportation	Enforcement of federal ban on HFC release during service/dismantling of MVACs	No Change in Classification

- The potential emission reductions in 2010 (if any) and 2020 in terms of million metric tons of CO_2-equivalent per year, including any co-benefits (e.g., reduction in emissions of criteria pollutants) or disbenefits (e.g., fuel penalty).

- The costs per $MTCO_2E$ and the total cost of implementation in 2010 (if applicable) and 2020 and the sectors that will bear the costs including any potential disproportionate impacts on small businesses or environmental justice sectors of the community. This discussion includes businesses or individuals (e.g., environmental justice community) that may be adversely impacted by the proposed strategy.

- The likely technical feasibility of the technology by describing the degree to which it or a similar technology has already been proven. If not applicable, the research/pilot studies that suggest the technological feasibility is likely to be within the next few years are cited.

- Additional considerations that pertain to the measure, such as if any other jurisdiction (state, county) has taken the action, whether the item falls under ARB jurisdiction or is a CAT strategy, whether ARB has legal authority, whether the item would be regulatory, when the item could be taken before the Board, and coordination with affected entities, trade associations, and/or government agencies.

Current State of Understanding

Appendices B and C include a complete listing of staff's analysis for each of the 63 recommendations / potential early actions listed in Table 2, exclusive of the landfill methane capture suggestion by the EJAC, which is already a discrete early action. Each summary has a unique identification number that is also listed in Table 2 for each measure; note that multiple measures may be addressed by the same summary.

The summaries in Appendices B and C represent ARB staff's current understanding of the ideas evaluated. It is acknowledged that in many instances, additional time, effort, and information are still needed for a more thorough compilation of all relevant and necessary information to support development as a regulation or other approach such as guidance.

Based on its current state of understanding, staff has made one of six recommendations for each measure it evaluated which are described below. One of these six recommendations is indicated for each of the strategies evaluated (see disposition column in Table 2).

- Previously Approved – No Change – applies to measures which were approved by the Board as early actions at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this early action is recommended.

- Previously Approved – Reclassify as a Discrete Early Action – applies to measures which were approved by the Board as early actions at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this early action be reclassified as a discrete early action measure.

- Proposed Measure – Add as a Discrete Early Action – applies to measures which are recommended for addition to the list of discrete early action measures.

- Proposed Measure – Add as an Early Action – applies to measures which are recommended for addition to the list of early actions.

- Proposed Measure – Continue to Evaluate in Scoping Plan – applies to measures proposed at the June 2007 Board meeting which are recommended for further evaluation in the Scoping Plan. A draft Scoping Plan is expected by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering these recommendations.

- Proposed Measure – Further Evaluation Needed – applies to measures proposed that require further information and evaluation prior to recommending that they be pursued an early actions. As additional information becomes available staff will consider whether it supports recommending these strategies as additions to the Board's list of commitments for reducing greenhouse gas emissions.

RECOMMENDATIONS FOR ADDITIONAL EARLY ACTIONS

The ARB staff is recommending that a total of 44 early actions be developed and brought to the Board for future consideration. These measures are recommended because staff's evaluation concluded that they are expected to yield significant GHG emission reductions, are likely to be cost-effective and technologically feasible, and can be brought back to the Board as full proposals in the 2007-2012 timeframe. Specifically, staff is recommending that 6 more discrete early actions be added to the list previously approved by the Board, two of which are new recommendations to be added to the list of those actions meeting the narrow definition of discrete early actions in that they are regulatory and will be enforceable by January 1, 2010. Furthermore, staff is recommending that 4 previously adopted early actions be reclassified as discrete early action measures. Cumulatively, these 44 total recommendations are expected to yield at least 42 $MMTCO_2E$ reductions by 2020, representing about 25% of the 2020 target.

Summary of Items Reviewed

Table 2 lists each of the items evaluated as potential early actions. It consists of the recommendations made by the EJAC, CAPCOA and the SCAQMD as well as additional strategies that were identified by stakeholders or ARB staff. Each of the strategies has been evaluated with the results of the evaluation presented in

Appendices B and C. The ‘Summary ID’ column of Table 2 cross-references each of these items to its summary in the appendices; the final disposition of each item is listed in the ‘Disposition’ column.

Items Addressed by Recently Adopted Regulations

The ARB recently adopted an off-road diesel rule[4] at its July 2007 Board hearing. This regulatory measure was not listed as an early action in the April 2007 ARB staff report. The regulation requires a reduction in off-road diesel engine particulate matter emissions, and is applicable to off-road engines such as those used by urban construction equipment. A possible way to achieve such pollutant reductions is via the electrification of construction equipment at urban sites. This particular example was submitted by the EJAC [refer to summary number B17 in Appendix B]; this recommendation is therefore encapsulated within the intent of a recently adopted regulation and was not further evaluated as part of the early action effort.

Measures Recommended as Additional Discrete Early Actions

The ARB staff’s recommendations concerning the addition of discrete early actions are summarized below. In addition to these measures staff closely evaluated many other measures as potential discrete early action measures. However, for reasons such as the non-regulatory nature of a measure, its implementation timeline, and others, they are not recommended for addition to the list of discrete early action measures. Additional information, including the specific rationale for the disposition of each strategy evaluated, may be found in Appendices B or C and is summarized in Table 2.

SF_6 Reductions in the Non-Electric Sector: This measure is recommended as an additional discrete early action measure. The strategy involves the potential ban of SF_6 in non-utility, non-semiconductor applications where safe, cost-effective alternatives are available. These applications may include magnesium production and casting operations, air quality tracer gas studies, and face velocity tests for laboratory hoods. The staff will investigate other possible uses of SF_6 during the development of the regulations.

Reduction of High GWP GHGs in Consumer Products: This measure is recommended as an additional discrete early action measure. The strategy involves the reduction of high-GWP GHGs used as propellants in aerosol products, tire inflators, electronics cleaning, dust removal, hand held sirens, hobby guns (compressed gas), party products (foam string), and other formulated consumer products when viable alternatives are available. Some data regarding emissions of greenhouse gases are available from a recent survey of consumer products, which may represent possible reductions within the discrete early action timeframe. Manufacturers are also currently being surveyed to determine the extent of usage of high GWP gases in several more categories of consumer products. These future survey results may lead to additional strategies with

[4] Staff report located at http://www.arb.ca.gov/regact/2007/ordiesl07/isor.pdf

emission reduction potential that can be pursued after the deadline for discrete early action items.

Measures Recommended for Reclassification as Discrete Early Actions

The ARB staff's recommendations concerning the reclassification of pre-existing early actions are summarized below. Additional information, including the specific rationale for the disposition of each strategy evaluated, may be found in Appendices B or C and is summarized in Table 2.

SmartWay Truck Efficiency: This measure is recommended to be re-classified as a discrete early action measure. The strategy involves requiring existing trucks/trailers to be retrofitted with the best available "SmartWay Transport"[5] and/or ARB approved technology. Technologies that reduce GHG emissions from trucks may include devices that reduce aerodynamic drag and rolling resistance. Aerodynamic drag may be reduced using devices such as cab roof fairings, cab side gap fairings, cab side skirts, and on the trailer side, trailer side skirts, gap fairings, and trailer tail. Rolling resistance may be reduced using single wide tires or low-rolling resistance tires and automatic tire inflation systems on both the tractor and the trailer.

Tire Inflation Program: This measure is recommended to be re-classified as a discrete early action measure. The strategy involves actions to ensure that vehicle tire pressure is maintained to manufacturer specifications. Specifically, the strategy seeks to ensure that tire pressure in older vehicles is monitored by requiring that tires be checked and inflated at regular service intervals. One potential approach would be to require all vehicle service facilities, such as dealerships, maintenance garages, and smog check stations, to check and properly inflate tires. It is also anticipated that signage at fueling stations clearly indicate the availability of compressed air at no charge. Staff also recommends that the feasibility of conducting an extensive outreach program be investigated.

Reduction of PFCs from the Semiconductor Industry: This measure is recommended to be re-classified as a discrete early action measure. The strategy involves establishing a PFC emissions reduction goal and determining measures to achieve that goal. There are several approaches the industry has either employed or committed to continue evaluating to reduce PFC emissions from semiconductor production, including process optimization (optimizing the use of PFCs, such as in the chamber cleaning process), alternative chemistry

[5] The United States Environmental Protection Agency (U.S. EPA) in collaboration with the freight industry has developed a voluntary program designed to increase energy efficiency while significantly reducing greenhouse gases and criteria pollutants. The program, known as the SmartWay Transport Partnership (SmartWay Transport), encourages trucking companies to use technologies that improve efficiency and reduce emissions. The SmartWay Transport also designates highly efficient and emission reduction technology packages as SmartWay Upgrade Kits which can be purchased at various SmartWay partner centers, dealerships, and service centers.
(http://www.epa.gov/otaq/smartway/documents/420f07027.htm)

development, emissions abatement; and recovery/recycling (separation of fluorinated compounds from other gases for further processing and reuse).

Green Ports: This measure is recommended as an additional discrete early action measure. The strategy involves providing an alternative source of power for ships while they are docked. For example, the ships can use cables to receive electricity from the shore, thereby allowing them to shut off their auxiliary engines, reducing emissions of air pollutants. Staff proposes to present the draft regulation to the Board as a measure to reduce nitrogen oxides (NO_x) and diesel particular (PM) emissions and to quantify the associated (carbon dioxide) CO_2 emission reductions. By focusing on NO_x and PM reductions, staff will address the local and regional health impacts of ships docked in California's ports, including any disproportionate impacts those emissions may have on surrounding communities.

Measures Recommended as Additional Early Actions

The ARB staff's recommendations concerning the addition of early actions are summarized below. In addition to these recommendations staff closely evaluated many other measures such as a green ship incentive program, and refinery methane emission reductions. However, for reasons such as a substantial lack of available information, technological barriers, implementation timeline, and others, they are not recommended for addition to the list of early actions. Additional information, including the specific rationale for the disposition of each strategy evaluated, may be found in Appendices B or C and is summarized in Table 2.

Refrigerant Tracking, Reporting, and Recovery Program: This measure is recommended as an additional early action. The strategy involves the reduction of emissions of high GWP GHGs through establishing requirements for enhanced monitoring, enforcement, reporting, and recovery. It may be determined that more than one strategy is required to effectively address the sources of interest and that the strategy or strategies are likely to include both regulatory and non-regulatory elements. Such strategies could include:

- Refrigerant Recovery from Decommissioned Refrigerated Shipping Containers*:* This consists of an assessment of the magnitude of the emissions from refrigerated shipping containers. Depending on results, the strategy may be similar to the one enforcing the federal ban on releasing refrigerants to the atmosphere from the servicing or dismantling of MVACS. After the recovery from a decommissioned container, it may be desirable to disable the refrigeration unit as well, which may require a regulation.

- Residential Refrigeration Program*:* This involves supporting existing voluntary programs to promote the upgrade of residential refrigeration equipment in need of repair, such as refrigerators and freezers. The program could potentially be expanded to include window unit air conditioners.

- <u>High-GWP Refrigerant Tracking, Reporting, and Deposit Program</u>: This strategy involves 1) expanding and enforcing the national ban on venting high-GWP GHGs (including fully emissive processes) during equipment/process lifetime; 2) requiring high-GWP GHG sales, use and energy use reporting as well as inspection and maintenance (I/M) and leak repair for equipment, cylinders, products, or systems with capacities above some CO_2E threshold; 3) requiring technician certification for sales, purchase, transport, recovery, reclamation, resale, I/M; and 4) establishing a high-GWP GHG deposit program and/or fines for emissive processes or leaky systems.

Cement (A): Energy Efficiency of California Cement Facilities: This measure is recommended as an additional early action. The strategy involves reducing CO_2 emissions from fuel combustion, calcination, and electricity use by converting to a low-carbon fuel-based production, decreasing fuel consumption, and improving energy efficiency practices and technologies in cement production.

Cement (B): Blended Cements: This measure is recommended as an additional early action. The strategy to reduce CO_2 emissions involves the addition of blending materials such as limestone, fly ash, natural pozzolan and/or slag to replace some of the clinker in the production of Portland Cement. Currently, ASTM cement specifications allow for replacement of up to 5% clinker with limestone. Most manufacturers could in fact replace up to 4% with limestone. Caltrans allows for 2.5% average limestone replacement until testing of the long term performance of the concrete is complete. Caltrans currently has over $1 million in task orders and is devoting considerable staff resources to the evaluation of limestone blending in cement. Caltrans also currently has standards for using flyash and slag in concrete. Other blending practices will be explored.

Anti-idling Enforcement: This measure is recommended as an additional early action. The strategy guarantees emission reductions as claimed by increasing compliance with anti-idling rules, thereby reducing the amount of fuel burned through unnecessary idling. Measures may include enhanced field enforcement of anti-idling regulations, increased penalties for violations of anti-idling regulations, and restriction on registrations of heavy-duty diesel vehicles with uncorrected idling violations.

Collaborative research to understand how to reduce GHG emissions from nitrogen land application: This measure is recommended as an additional early action. The strategy involves the identification of methodologies for better characterizing California's nitrogen cycle. An important first step to better characterizing the relationship between nitrogen land application and nitrous oxide formation in California agriculture, landscaping and other uses as well as opportunities for emission reductions is a collaborative research effort with stakeholders. The research is expected to focus on identifying optimal ways to reduce nitrous oxide emissions while increasing soil retention of nitrogen for plant uptake. As part of the research the ARB will collaborate with the California Department of Food and Agriculture, Department of Pesticide Regulation, commodity groups, and other stakeholders. The research is expected to ultimately support the development of guidance to improve the characterization of nitrous oxide emissions from nitrogen land applications as well as identify effective strategies for emission reductions.

Process Forward for Regulatory Items

All discrete early action measures and the majority of the other early actions will enter into the conventional regulatory development process. This process involves public workshops and the consideration of stakeholder input, followed by the formal regulation development, which includes a public hearing where the Board considers the staff recommendation. If the Board adopts the regulation or an amended regulation, then it must be reviewed and approved by the Office of Administrative Law (OAL) before becoming law. Though the non-regulatory strategies such as guidelines will not become binding mandates, they will go through a similar process of public participation. This open process ensures that the regulatory development of each strategy that the staff recommends to the Board is informed by the best and most up-to-date information.

ADDITIONAL CONSIDERATIONS / CAT STRATEGIES

ARB has or will be adopting several strategies not discussed explicitly in this report that will yield significant GHG reductions by 2020. Most notably, the regulation that the Board adopted in response to AB 1493, which mandated the reduction of greenhouse gas emissions from passenger vehicles, is expected to account for 30 $MMTCO_2E$ by 2020. Other diesel PM, ozone-precursor, and State Implementation Plan (SIP) measures are also expected to have climate co-benefits whose magnitudes are yet to be determined.

In its April 2007 draft report entitled ‘Climate Action Team Proposed Early Actions to Mitigate Climate Change in California’, the CAT identified early actions external to the ARB that may yield up to 68 $MMTCO_2E$ reductions by 2020. In addition to ARB, members of the CAT have begun work on implementing many of the strategies outlined in the April 2007 draft report. Although not under statutory mandate to do so, the other CAT members expect to have several items implemented through regulations by January 1, 2010; these 13 strategies are expected to result in emission reductions of approximately 7 $MMTCO_2E$ with some reduction estimates still to be calculated. The same CAT members have also identified 41 additional measures for the post-2010 timeframe, which are expected to yield reductions in greenhouse gas emissions on the order of 61 $MMTCO_2E$ by 2020.

The ARB is in the process of developing a comprehensive Scoping Plan, due in late 2008, which will outline the multifaceted approach to meeting the 2020 emissions reduction target required by AB 32. The Scoping Plan will evaluate opportunities for sector-specific reductions, integrate synergistically all ARB and CAT early actions and additional GHG reduction measures, and define the role of any potential market mechanisms. The analyses of many potential GHG emission reduction strategies that are not recommended as early actions are currently underway and will continue as part of the Scoping Plan development. Recommendations regarding the form of these additional GHG reduction measures (e.g. regulatory, non-regulatory, market-based) will be included in the Scoping Plan.

CONCLUSIONS / RECOMMENDATIONS

At its June 2007 hearing, the Board asked staff to conduct additional analyses of stakeholder suggestions for early actions. Staff has completed this task as well as the further evaluation of additional potential early action measures, and recommends that the list of early action measures be expanded to 44. Nine of these strategies meet the AB 32 definition of discrete early action measures, which is three times the number of original discrete early action measures currently approved by the Board. The ARB recognizes that California must act quickly and decisively now to begin the long road to mitigating the most serious impacts of global warming, and is committed to pursuing the full list of 44 early actions.

The revised list of early actions as recommended by ARB staff is a more ambitious plan than originally proposed and is a complement to the actions of the Climate Action Team members and many other entities in California, the U.S., and the world who are acting now for climate protection. Discrete early action measures that will be in place and enforceable by 2010 include the original list of 3 strategies, plus an additional 6 measures in the transportation and commercial sectors. In addition, 5 new measures as suggested by stakeholders or staff analysis will also be pursued as early actions, but will be implemented post-2010 or are not necessarily regulatory in nature. Cumulatively, all 44 early actions have the potential for reductions of 42 $MMTCO_2E$ by 2020.

The revised early action plan is a comprehensive framework of regulatory and non-regulatory elements that will result in significant and effective GHG emission reductions. The revised early action plan will receive public input at a September 17, 2007 workshop and will be considered by the Board at its October 25-26, 2007 hearing. If approved, each early action will be developed through an open public process.

GLOSSARY OF TERMS AND ACRONYMS

AB 32 – Assembly Bill 32, the Global Warming Solutions Act of 2006

ARB – Air Resources Board

CAPCOA – California Air Pollution Control Officers Association

CAT – Climate Action Team, a committee of multiple state agencies led by the Secretary of Cal/EPA

CO_2 – carbon dioxide; a byproduct of fossil fuel combustion, cement production, and other natural processes

Discrete Early Actions – Greenhouse gas reduction measure underway or to be initiated by ARB that meets the AB 32 legal definition as identified by the Health and Safety Code Section 38560.5. Discrete early actions are regulations to reduce greenhouse gas emissions adopted by the Board and enforceable by January 1, 2010.

Early Actions – Greenhouse gas reduction measures underway or to be initiated by ARB in the 2007 – 2012 timeframe. These measures may be regulatory or non-regulatory in nature.

EJAC – Environmental Justice Advisory Committee

GHG – greenhouse gas or gases; defined in AB 32 as including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride; also known as “the Kyoto six”

GWP – global warming potential, the relative warming of a greenhouse gas as compared to carbon dioxide which has a GWP of 1.0.

HFCs – Hydrofluorocarbons; a class of compounds whose molecules consist of carbon, hydrogen, and fluorine atoms typically used in air conditioning systems and as propellants

HSC – (the California) Health and Safety Code

LCFS – Low Carbon Fuel Standard

$MMTCO_2E$ – million metric tons (of) carbon dioxide equivalent (gases)

MVAC – motor vehicle air conditioning (systems)

OAL – California Office of Administrative Law

OHRV – Off Highway Recreational Vehicle

PFCs – perfluorocarbons, a class of compounds derived from hydrocarbons by replacement of hydrogen atoms by fluorine atoms. PFCs are made up of atoms of carbon, fluorine, and/or sulfur, and are mostly used in the semi-conductor industry

SCAQMD – South Coast Air Quality Management District

SF_6 – sulfur hexafluoride; a highly stable non-conducting chemical used for and emitted from various industrial processes and in the manufacturing of electrical circuitry

APPENDIX A – EJAC, CAPCOA, and SCAQMD Recommendations

ARB Discrete Early Action Measures
as proposed by
the Environmental Justice Advisory Committee on the Implementation of the Global Warming Solutions Act of 2006

Number	Description
1	Improved landfill methane capture
2	Require HFC-134a reductions through evaluation of refrigerants in de-commissioned or stored cargo containers, commercial and residential HVAC system leakage, auto dismantling/crushing facilities (i.e., requiring HFCs be removed from cars prior to scrappage)
3	Manure management[1]
4	Reduce venting/leaks from oil and gas systems
5	Heavy-duty vehicle emissions, efficiency improvements[2]
6	Cool automobile paints[3]
7	Port electrification
8	Transportation refrigeration, electric standby
9	Truck stop electrification with incentives for truckers
10	Tire inflation program
11	Require low GWP refrigerants for new MVACs[4]
12	Add AC leak tightness test and repair to Smog Check
13	Wafflemat system for concrete slab foundations
14	Demonstrate use of shoreside generators as bridge to electrical hook-up
15	Green ship incentive program
16	Anti-idling requirement for cargo handling equipment at ports
17	Require the electrification of airport ground support equipment
18	Require the electrification of construction equipment at urban sites
19	Adopt a regulation and or incentive program to take advantage of emerging hybrid technology for medium duty delivery trucks
20	Relatively inexpensive energy savings measures with short pay back times for cement industry
21	Explore a greenhouse gas and mercury emission performance standard for cement facilities equivalent to the level achievable through conversion from coal to natural gas
22	Relatively inexpensive energy savings measures with short pay back times for fossil fuel power plants built prior to 1980[5]
23	Relatively inexpensive energy savings measures with short pay back times for refineries[6]
24	Accelerate the replacement of cargo handling equipment at ports[7]
25	Enclose dairy barns to capture methane[8]
26	Adopt South Coast and San Joaquin rules on enclosed composting facilities statewide[9]
27	Establish necessary rules and or emissions thresholds for transmission to local Air Districts for the phase out, by 2010, of power plants built prior to 1980 that generate over 100 MW of electricity and provide incentives for clean energy production in their place[10]
28	Prohibit fuel oil burning for base load generation of electricity in facilities100 MW or greater and built prior 1980[11]
29	We recommend CARB undertake and adopt regulatory measures that require recycling of waste gases at refineries instead of dumping or incinerating them[12]
30	Adopt regulatory measures to eliminate the methane exemptions granted to refineries and require methane control measures at refineries[13]

31	Identify and implement energy efficiency measures at refineries that include, but are not limited to, conducting an energy audit. This audit shall consider and address, at least: a) Use of clean, renewable energy for refinery electricity consumption b) The impact of heavier crude oil modifications on GHG emission c) Other energy efficiency measures[14]
32	We recommend CARB undertake and adopt regulatory measures that require recycling of waste gases at oil production sites instead of dumping or incinerating them[15]
33	Adopt regulatory measures to eliminate the methane exemptions granted to oil production sites and require methane control measures at oil production sites[16]
34	Identify and implement energy efficiency measures that include, but are not limited to, conducting an energy audit at oil production sites. This audit shall consider and address, at least: a) Use of clean, renewable energy for oil production site electricity consumption b) Other energy efficiency measures.[17]

Early Action Measures to be Forwarded by ARB to the CAT Team

The Committee recommends that all CAT agencies with jurisdiction in the area of energy generation, procurement, siting, permitting, rate-setting and renewable energy deployment in both electricity and transportation sectors, conduct the following:

1) Quantify and publicly provide the air emission and cumulative impacts of new power plant construction in CA and report to CARB the implications for the achievement of the state's climate and air quality goals;
2) Require proponents of new power plant construction to conduct a thorough and robust renewable energy alternatives assessment. If a more carbon-beneficial combination of energy producing or saving sources is available, then the utility should be required to pursue that avenue. This process should begin with all currently approved and expected power plants;
3) Report to CARB on the progress of existing renewable energy deployment programs and identify obstacles to the achievement of the state's renewable energy goals;
4) Perform an audit, to be publicly available, of existing and planned low-income rate assistance, energy efficiency, solar, and green building programs and identify barriers that impede local community participation.

Note: The Committee supports electrification of engines when coupled with efforts to increase use of clean, renewable energy sources such as wind and solar.

---

[1] During the development of this measure ARB must identify methods that would eliminate the NOx emissions which result from this technology in order to comply with the prohibition in AB 32 against backsliding on criteria pollutants.
[2] Particularly promising avenues include requiring or incentivizing: Use of wide base tires, Use of automatic tire inflation systems, Use of low viscosity lubricants, Improving freight logistics, and Pursuit of hybrid truck technology. ARB should undertake a complete life cycle analysis before suggesting use of fuel additives.
[3] Any regulation developed would have to ensure that the new paint formulations did not cause backsliding on criteria pollutants.
[4] Any chosen replacements must first undergo a complete life cycle analysis and multi-media toxicity analysis.

[5] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[6] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[7] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[8] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measure because it met the criteria established by the committee.

[9] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[10] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[11] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[12] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[13] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[14] This measure was not included in the CARB report on Early Action Measures, but was received by CARB and the committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[15] This measure had not been previously received by CARB and was added to the Early Action Measures list by the Committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[16] This measure had not been previously received by CARB and was added to the Early Action Measures list by the Committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

[17] This measure had not been previously received by CARB and was added to the Early Action Measures list by the Committee. The measure was evaluated and recommended as Early Action Measures because it met the criteria established by the committee.

07-7-4

CAPCOA
CALIFORNIA AIR POLLUTION CONTROL OFFICER'S ASSOCIATION

980 Ninth Street, 16th Floor
Sacramento, CA 95814
(916) 449-9603 (916) 449-9604 FAX
www.capcoa.org

May 14, 2007

Ms. Catherine Witherspoon
Executive Officer
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: Proposed Early Action Measures Under AB 32

Dear Ms. Witherspoon,

The California Air Pollution Control Officers Association is writing to support your efforts to identify discrete early action measures to help secure the earliest possible reductions in greenhouse gas emissions, and to urge you to include additional measures and timeframes in your final proposal. We also would like to offer the support and resources of local air districts in developing and implementing early action measures.

Local air districts recognize the critical importance of early reductions to delay the approach of a climate change "tipping point" and to effect a meaningful slowing of the process of climate change. We also recognize the extraordinary resource demands facing the ARB as you implement the requirements of AB 32. We believe that by relying on local air districts for specific tasks, the ARB will be able to reserve crucial resources for those activities that should be developed and implemented centrally.

CAPCOA supports the inclusion of the measures listed in the ARB's April 20, 2007 draft proposal. We believe additional measures can and should be identified as Group 1 measures. We also believe that more specific time frames should be included for measures in Group 2 and Group 3. Most importantly, we believe there are existing processes and programs that can be effectively leveraged for early reductions of greenhouse gases, and we urge you to include specific tasks and milestones for them in your final list of measures.

The local districts understand the difficulties identifying specific measures that can be adopted and implemented in the short time period called for in AB 32. We recommend actions in five key areas that ARB can take to secure these reductions quickly and without investing significant additional resources.

*

Recommendation 1: Prioritize SIP rulemaking. CAPCOA recommends that ARB review proposed SIP measures and rank them on the basis of criteria pollutant reductions, public health protection, and greenhouse gas reduction potential. Rules that rank high in all three areas should be given higher priority in the rulemaking calendar. This additional review will not add substantially to workload already planned, but will define GHG reductions that can be achieved in the near term without compromising progress towards clean air or undermining protection of public health.

Recommendation 2: Review Existing Rules. CAPCOA recommends that you perform a review of existing state and local rules, similar to an "All Feasible Measures" review that would identify existing rules that, whether expressly intended or not, result in significant reductions of GHGs. Rules that are so identified could be more quickly adapted for statewide implementation and adopted by the ARB. Some local districts have already adopted and implemented regulations intended to reduce GHG emissions; many others have regulations for criteria pollutants which, by virtue of the way the rules are structured, also secure significant collateral GHG reductions. We believe that with a modest investment of resources, perhaps relying on a contractor who could work with a CAPCOA committee, ARB could identify rules with potential for statewide GHG reductions. Because these rules have already been adopted and implemented, much of the preparatory work has been done and the feasibility and costs are well documented; this should shorten both the time and resources needed for state rulemaking. CAPCOA has already begun this review and we look to share initial results with you in the near future.

CAPCOA also recommends that ARB use a focused workgroup process (which you have already discussed with us) to tap district staff resources and expertise with specific source categories to identify discrete early reductions that could be achieved in each category. We believe this process could identify early reduction potential in the six categories ARB has identified for reporting and rulemaking, and could be used to accomplish some of the necessary steps to speed adoption by the ARB. The workgroup process could also be used to build on the review of local regulations (described above) and identify opportunities for additional reductions of greenhouse gases within the existing air pollution program structure. Some local districts have already begun this review and others plan to begin soon. CAPCOA believes such a coordinated workgroup process could identify potential GHG reductions and secure them in the near term through local rule amendments that implement a consistent statewide standard – similar to a suggested control measure. We recommend that this process be included in your final list, and would be happy to work with you in defining an appropriate schedule and associated emission reduction potential.

Recommendation 3: Minimize Impacts of New Stationary Sources. CAPCOA recommends that ARB work with the districts to develop a coordinated approach to reviewing greenhouse gas emissions from significant stationary sources in categories that also emit significant amounts of GHGs. As you know, the most environmentally effective and cost effective emission reductions are those implemented before a project is built. The challenge of reaching the 1990 baseline will be easier to meet if we ensure that economic growth occurs along the path of least climate impact. Local air districts already require permits and preconstruction review for such sources, which provides an efficient and effective platform to identify and address GHG emissions from new or modified sources in categories of concern. ARB could establish a general framework for including a review of GHG emissions in the local permitting process. The framework should also identify appropriate local, regional, or global mitigation strategies. This process would be analogous to the development of review programs for toxic air contaminants in the late 1980s and early 1990s. In fact, because of district obligations under CEQA, districts may be required to address GHG emissions associated with new permits regardless of any action by ARB. The outcome would be better coordinated with ARB participation at the outset to identify the scope of the review and the mitigations to be considered.

Recommendation 4: Leverage CEQA Mitigations. CAPCOA recommends that ARB work with local districts to coordinate approaches to the review of GHGs under CEQA and capture the reductions that result from mitigation. Local air districts routinely review the impacts of a variety of development projects under CEQA. Local governments are currently contacting air districts with questions about how to incorporate climate change and address GHG emissions of projects, and are seeking specific guidance on GHG significance thresholds for projects. CAPCOA's Climate Protection Committee and Planning Managers Committee are working on this now, and we would like to include ARB staff in this effort. We believe that a focused effort to identify thresholds and mitigation measures could result in practical reductions in the near term through the CEQA process. We recommend that ARB include timelines and commitments to such a process on the early action measures list, and we would be happy to work with you on an appropriate schedule and associated emission reduction potential.

Recommendation 5: Capture Voluntary Reductions. CAPCOA recommends ARB work with local districts to establish mechanisms to promote, track, verify, and capture voluntary reductions in GHGs. As you are well aware, there is tremendous interest in voluntary reductions on the part of business, local government, and the general public. CAPCOA believes this interest should be aggressively pursued. Many local air districts are already working with local stakeholders to identify and organize voluntary reduction efforts. CAPCOA also has a Climate Protection Committee that is tasked, among other things, with compiling voluntary reduction strategies and other materials to support individual districts in this area. We suggest ARB work with us to compile information, and that ARB rely on local districts to help form your reporting, verification, and tracking structure for early reduction efforts. We believe ARB should include milestones for implementing this in your final list of measures, and will work with you to identify associated emission reduction targets.

Summary

In closing, CAPCOA applauds ARB's efforts to identify and secure early reductions of greenhouse gases under AB 32. We urge you to include additional Group 1 early action measures on your final list, and to establish time frames for the measures in Group 2 and Group 3. We specifically recommend that ARB 1) prioritize SIP reductions to maximize collateral GHG reductions, 2) review existing local rules to identify potential statewide measures or local enhancements, and use district resources in workgroup efforts on specific source categories with significant GHG emissions, 3) coordinate with districts on a strategy to use existing permit programs to review and mitigate greenhouse gases from significant stationary sources, 4) coordinate with districts on review and mitigation of GHGs under CEQA, and 5) rely on local air district resources to implement early reductions through coordinated voluntary programs,

Thank your for your consideration of our recommendations.

Sincerely,

Larry R. Allen
President

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

May 7, 2007

Via email

Mr. Bart Croes
Division Chief
California Air Resources Board
1001 I Street
Sacramento CA 95812

Re: Proposed Early Actions to Mitigate Climate Change in California

Dear Mr. Croes:

Thank you for the opportunity to comment on the State's Proposed Early Actions to Mitigate Climate Change in California. This effort will contribute significantly to the overall strategy to reduce greenhouse gases in the state. The following comments are offered for your consideration.

The report includes 3 tables: Table 1, Group 1 – Early Action Measures; Table 2, Group 2 – Additional GHG Reduction Measures Underway or Initiated by ARB in 2007 – 2009 Period; and Table 3, Group 3 – ARB Air Pollution Controls for 2007 – 2009 Adoption with Potential GHG Reductions or Other Climate Co-Benefits. Relative to the measures in Group 1, which will be adopted and implemented by January 1, 2010, SCAQMD staff recommends including a measure to accelerate hybrid penetration, as this technology is already well developed and readily available. At a minimum, this measure should be added to Group 3 if it is not added to Group 1. In addition, the measure on Low Carbon Fuel Standard (1-1) needs to be evaluated in light of the recent Stanford study regarding potential negative implications of E-85.

For Group 2, it would be very helpful for CARB staff to identify years for adoption and implementation for each measure to enable a better sense of priority. Providing preliminary information for potential reductions would also help to understand these measures and their relative benefits. Measure 2-16, Port Electrification should be moved to Group 3 as part of the port measures. There are also several measures that SCAQMD staff would like to see adopted by 2009, not just underway or to be initiated. These are measures 2-9 - Energy Efficiency, 2-13 – Transportation (light-duty vehicle standards), and 2-14 – Transportation (heavy-duty vehicle emission reductions and efficiency improvements.

For Group 3, there are SIP measures in the SCAQMD 2007 Air Quality Management Plan that should be added:

- Evaporative Emission Standards for Recreational Boats and Off-Road Recreational Vehicles; and
- Auxiliary Ship Engine Cold Ironing.

In addition, CARB staff should consider adding one of the SCAQMD measures in the 2007 Air Quality Management Plan – Accelerated Use of Plug-In Hybrids for Light- and Medium-Duty Vehicles, if it is not added to Group 1.

The report also includes tables in Attachment A with the status of assignment to Groups 1, 2, or 3, or deferred to the Scoping Plan. Sixteen of the 24 items in the table are deferred to the Scoping Plan, which is not due for another 18 months. SCAQMD staff recommends that work on these concepts be initiated right away so emission reductions can be realized as soon as possible.

SCAQMD staff also concurs with comments made at the April 30th Environmental Justice Advisory Committee meeting that the report could be improved by adding information on the more than 70 proposals received and the reasons why many ideas were not included in this report.

Thank you again for the opportunity to contribute to this important policy document. If you have any questions or would like to discuss this further, please call me at (909) 396-3104 or Elaine Chang at (909) 396-3186.

Sincerely,

Jill Whynot

Jill Whynot
Planning and Rules Manager

EC:JW

cc: Alberto Ayala, CARB
M. Robert, CARB

South Coast
Air Quality Management District
AQMD
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

May 9, 2007

Via email

Mr. Bart Croes
Division Chief
California Air Resources Board
1001 I Street
Sacramento CA 95812

Re: Additional SCAQMD Comment - Proposed Early Actions to Mitigate Climate Change in California

Dear Mr. Croes:

South Coast Air Quality Management (SCAQMD) staff sent comments on May 7, 2007 regarding the Proposed Early Actions to Mitigate Climate Change in California. We have an additional comment that CARB staff should consider for inclusion.

An early action measure should be added to require that natural gas supplies for the state be at a Wobbe index of 1360 or lower. As you know, higher carbon content will result in increased carbon dioxide emissions. It is possible to achieve this level by securing natural gas sources with low Btu content, removing heavier hydrocarbon components by a condensing process, injection of inert gas such nitrogen, and blending high Btu gas with low Btu gas. This would have concurrent nitrogen oxides benefits, as well. Please see control measure #2007CMB-04 in the draft 2007 Air Quality Management Plan for additional information.

Thank you for considering this addition to the early action list. If you have any questions or would like to discuss this further, please call me at (909) 396-3104 or Elaine Chang at (909) 396-3186.

Sincerely,

Jill Whynot

Jill Whynot
Planning and Rules Manager

EC:JW
cc: Alberto Ayala, CARB
M. Robert, CARB

Cleaning the air that we breathe...

Jill Whynot
07-7-4

Suggested Changes to Early Action Measures
by SCAQMD Staff
June 21, 2007

Add New Group 1 (Early Action Measures)

- Accelerate hybrid penetration
- Wobbe index $\leq$ 1360 for natural gas

Group 2 Measures (underway or to be started in 2007 – 2009)

- Add specific adoption and implementation dates

▪ 2-9	Energy Efficiency	adopt by 2009
▪ 2-13	Transportation (LD)	adopt by 2009
▪ 2-14	Transportation (HD)	adopt by 2009
▪ 2-16	Port Electrification	adopt by 2009

Add to Group 3 Measures (adopt 2007 – 2009)

- Evaporative Emission Standards for Recreational Boats and Off-Road Recreational Vehicles
- Auxiliary Ship Engine Cold Ironing
- Accelerated Use of Plug-In Hybrids (if not added to Group 1)

Consider Other Measures Suggested by CARB Environmental Justice Advisory Group

APPENDIX B – Staff Evaluation of Stakeholder Recommendations / Additional Strategies

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B01*
ID NUMBER:	*N/A*
TITLE:	*CAPCOA RECOMMENDATIONS*
PROPONENT:	*CALIFORNIA AIR POLLUTION CONTROL OFFICERS ASSOCIATION (CAPCOA)*

2. Staff Recommendation

Work with CAPCOA to pursue its recommendations. The proposed CAPCOA working group can provide input into the development of the scoping plan for AB 32. Other recommendations could help in quantifying greenhouse gases reductions.

3. Action Description

CAPCOA makes five recommendations. These recommendations can support identification and quantification of greenhouse gas reductions as we proceed on AB 32 implementation.

PRIORITIZE SIP RULEMAKING

CAPCOA recommends that ARB's SIP rulemaking be ranked taking into consideration greenhouse gas emissions. The requirements of the federal Clean Air Act dictate that we proceed expeditiously with the measures needed to meet ozone and PM2.5 standards. The most critical near-term SIP rulemakings are already underway and all must be considered top priorities in order to meet federal deadlines. However, as we develop new longer-term SIP measures we will look for opportunities to reduce both criteria pollutants and greenhouse gases.

REVIEW EXISTING RULES

CAPCOA recommends a workgroup process that taps district resources and expertise to identify potential greenhouse gas reductions that could be achieved consistently statewide through local rulemaking. This would be similar to the "suggested control measure" approach that has been used for criteria pollutants. We propose to work with CAPCOA to initiate this process to support development of the AB 32 scoping plan.

MINIMIZE GHG IMPACTS OF NEW STATIONARY SOURCES

CAPCOA recommends that ARB work with local air districts to minimize impacts of new stationary sources. It suggests a coordinated approach to reviewing significant stationary sources in categories that also emit significant amounts of greenhouse gases.

The local permitting process and the environmental review (CEQA) process are suggested as possible mechanisms for achieving GHG emissions mitigation.

Staff suggests a joint effort to identify stationary source technologies for new sources that would reduce both criteria pollutant and greenhouse gases. This could include promoting development of new technologies that achieve multiple benefits.

LEVERAGE CEQA MITIGATIONS AND CAPTURE VOLUNTARY REDUCTIONS

CAPCOA recommends that ARB work with local air districts on approaches to the review of greenhouse gas impacts under the California Environmental Quality Act (CEQA) process, including GHG significance thresholds for projects, and to develop a process for the capturing of reductions that result from CEQA mitigations.

The Governor's Office of Planning and Research is charged with providing statewide guidance on CEQA implementation. With respect to quantifying any reductions that result from project level mitigation of greenhouse gas emissions, we would like to see air districts take a lead role in tracking such reductions in their regions.

4. Potential Emission Reductions

To be estimated during scoping plan development or rulemaking process.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

To be assessed during scoping plan development or rulemaking process.

6. Technical Feasibility

To be assessed during scoping plan development or rulemaking process.

8. Division: Planning and Technical Support Division
Staff Lead: Jeff Weir
Section Manager: Ravi Ramalingam
Branch Chief: Kurt Karperos

9. References:

Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan, April 26, 2007.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B02*
ID NUMBER: *NA*
TITLE: *REFRIGERANT TRACKING, REPORTING AND RECOVERY PROGRAM*
(REFRIGERANT RECOVERY FROM DECOMMISSIONED REFRIGERATED SHIPPING CONTAINERS, RESIDENTIAL REFRIGERATION PROGRAM, HIGH-GWP TRACKING/REPORTING/REPAIR/DEPOSIT PROGRAM)
PROPONENT: *STAKEHOLDER SUGGESTION- ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE, ARB STAFF*

2. Staff Recommendation

This combination of measures is recommended for addition to the list of early actions. The Board date for consideration of these items is anticipated in 4^{th} quarter of 2011. It is presented as one strategy given the interrelated objective, which is to reduce emissions of high-GWP GHGs through establishing requirements for enhanced monitoring, enforcement, reporting, and recovery. It may be determined that more than one strategy is required to effectively address the sources of interest and that the strategy or strategies are likely to include both regulatory and non-regulatory elements.

3. Early Action Description

Below is a brief description of potential approaches for addressing each of the source categories considered. Staff will explore the most efficient opportunities for achieving the largest reductions from the below categories which may translate into a single or multiple strategies.

Refrigerant Recovery from Decommissioned Shipping Containers: This action consists of an assessment of the magnitude of the emissions from refrigerated shipping containers. Depending on results, the strategy may be similar in scope to the measure aimed at enforcing the federal restrictions on refrigerant venting during servicing or dismantling of motor vehicle air conditioning systems (MVACS). After the recovery from a decommissioned container, it may be desirable to disable the refrigeration unit, which may require a regulation. Enforcement personnel and federal and local air management district assistance would be needed.

Residential Refrigeration Program: This involves supporting existing voluntary programs to promote the upgrade of pre-2000 residential refrigeration equipment in need of repair, such as refrigerators and freezers. The program could potentially be expanded to include window unit air conditioners (A/Cs); upgraded HVAC units are not recommended, as the costs are likely significant and would disproportionately impact lower-income people.

A statewide effort to support programs for expanding the upgrading of old appliances to Energy Star efficiencies or better should be coordinated with various local utilities' voluntary programs and the US EPA's RAD program[1]. Given the utilities lead role in such programs, the ARB's role would be expected to consisting of enhancing its outreach efforts to underscore the benefits of participating in such programs. This program could also be coordinated with a foam recovery program, especially if automated recovery of refrigerant, foam, and scrap metal is implemented.

This program will likely result in an increased number of refrigerators entering the waste stream that will need to be properly recycled to achieve GHG emission avoidance. However, if all waste refrigerant, foam, and other materials are properly recycled/destroyed, direct GHG emissions avoidance benefits may be significant, as well as indirect GHG emissions avoidance due to energy efficiency gains[2].

Part of the residential refrigeration program includes a strategy to be developed in collaboration with the US EPA to enhance the enforcement of end-of-life (EOL) recovery of refrigerant[3].

Insulation foam contained in residential appliances will be addressed in another strategy, but there may be some overlap between refrigerant and foam recovery for appliances if the entities involved in manual refrigerant removal (which requires US EPA technician certification) are also able/willing to perform manual foam removal on appliances at end-of life (EOL).

The proposed measure will be voluntary, and ARB's role will be to promote replacement through coordination/outreach efforts with the utilities, the US EPA, and the California Energy Commission (CEC), which will enhance public awareness of energy savings and GHG benefits associated with the program.

For maximum effectiveness, this program will also have to be coordinated with ARB's planned end-of-life enforcement and foam recovery measures to ensure that old residential appliances are properly disposed of and high global warming potential (GWP) refrigerants/foams are properly recovered/recycled or destroyed.

High-GWP Tracking/Reporting/Repair/Deposit Program: This strategy involves the following: 1) expanding and enforcing the national ban on venting high-GWP GHGs (including fully emissive processes) during equipment/process lifetime; 2) requiring high-

[1] http://www.epa.gov/ozone/snap/emissions/radp.html

[2] Dave Godwin, USEPA, personal communication, 7/06.

[3] The CFC-12 refrigerant/CFC-11 foam blowing agent combination was used for many years in residential refrigerators and freezers, and phaseout of HCFC-141b from appliance foam has only been occurring in the past four years. New refrigerators and freezers generally contain HFC-134a as the refrigerant and HFC-245fa as the foam blowing agent. Currently, ODS recovery is mandated by federal law, and venting HFCs is forbidden, but enforcement is weak and venting is not well-defined. Additionally, EOL technician certification for recovery/reclamation is only required for ODSs and is subject to little oversight/enforcement; the EOL recovery regulation would extend the certification requirement to other high-GWP GHGs and would call for additional oversight/enforcement at transfer stations, landfills, and other disposal facilities.

GWP GHG sales, use and energy use reporting as well as inspection and maintenance (I/M) and leak repair for equipment, cylinders, products, or systems with capacities above some CO_2E threshold; 3) requiring technician certification for sales, purchase, transport, recovery, reclamation, resale, I/M; and 4) establishing a high-GWP GHG deposit program and/or fines for emissive processes or leaky systems.

Currently, Section 608 of the CAAA limits intentional venting of ODSs and HFCs, requires record keeping for systems employing more than 50 lbs of an ODS, and requires technician certification for ODS systems (I/M, repair, recovery, reclamation). High-GWP GHG sales are only restricted to ODSs in cylinders (not pre-charged equipment); the sales restriction does not apply to HFCs.

Reporting, in addition to record-keeping for ODS systems > 50 lbs, is required in SCAQMD (Rule 1415), and it is proposed that ARB implements a high-GWP GHG reporting requirement rather than record-keeping only. Reporting would be for any high-GWP GHG above a specified CO_2E threshold (extending beyond ODSs). The permanent reporting protocol could apply to any high-GWP GHG bought, sold, or used, by any manufacturer, retailer, distributor, repair person/technician, auditor, facility/corporate parent. Production plus imports into California (gas in cylinders or as an equipment charge) can be checked against use and exports out of California for mass balance purposes.

High-GWP GHG sales will be restricted to certified technicians (i.e., consumers cannot not buy cans or cylinders of high-GWP GHGs over some threshold value), which differs from current federal law which only limits sales of ODSs to certified technicians (except for ODS refrigerants contained in air conditioners and refrigerators).

The deposit program could apply to cylinders (raw chemical) or pre-charged equipment (such as refrigerators, A/Cs, vending machines, etc.)[4]. Furthermore, fines could be assessed based on annual use reporting and auditing for systems above some CO_2E threshold. Reporting will have little to no impact on leaking/emissive equipment if there are not financial disincentives in excess of refrigerant costs (i.e., the deposit or fine should cost more than refrigerant needed to recharge a leaky system, so that leaks are promptly fixed).

Deposit/return and/or fine programs would encourage leak-tightness and recovery of high GWP GHGs, as well as encourage upgrading of old, leaky equipment. A similar program has been adopted in Australia, and industry groups are voluntarily considering a deposit/return program in the US.

Adoption of this measure will require a blend of regulatory/non-regulatory approaches, as it will extend current regulations and also require a collaborative effort with the US EPA to enforce what is already established by law.

4. Potential Emission Reductions

[4] Consumer goods would be more difficult to subject to deposit and return since they are intended to be fully emissive, but it is believed that purchases over a given CO2E limited to certified technicians will inhibit consumers from buying more than small numbers of product.

Refrigerant Recovery from Decommissioned Shipping Containers: There is insufficient data on the emissions from this source. For the decommissioned shipping containers, it is estimated that the HFC-134a refrigerant bank at end-of-life could be approximately 15,000 $MTCO_2E$ per year in the area surrounding the Ports of Long Beach and Los Angeles. This is based on the estimated Los Angeles-Long Beach fraction of world shipping container activity of approximately 8 percent and 30 percent of the total container population consists of refrigerated shipping containers. The percent of refrigerated containers that a ship may carry varies between 10 to 50 percent of the total container capacity. The estimated Los Angeles-Long Beach fraction of world refrigerated shipping container activity applied to the estimated annual turnover rate of refrigerated shipping containers has been estimated to be 100,000. The refrigerant charge in modern shipping containers ranges from 13 to 16 pounds. If these containers are allowed to accumulate, the bank could become on the order of 0.1 MMTCO2E in a 5 to 10 year period assuming a 10 pound refrigerant charge at decommissioning. Thus, the reduction potential of a mitigation strategy for this source would be less than 0.1 MMTCO2E in 2020. In addition, given that these shipping containers may last from 20 to 30 years, there may be a significant number of older CFC-based systems. Finally, it is important to determine what happens to the shipping containers as they approach end-of-life.

Residential Refrigeration Program: Estimated annual emission reductions of 0.8 $MMTCO_2E$ are possible for refrigerant recovery[5]. Of the 0.8 $MMTCO_2E$ of annual emissions avoided for refrigerant recovery, about 0.7 is due to recovery of R-12 refrigerant. This estimate does not include the benefits from deploying more efficient systems sooner (see energy efficiency calculations, below).

Although refrigerant recovery is currently supposed to occur at the time of disposal, destruction of refrigerant is not required, and it is generally assumed that recovered/reused refrigerant will eventually be emitted.

The CO_2E emissions avoidance was calculated for 2005, and only refrigerators and freezers going to landfills were considered; numbers of pre-2000 appliances in need of repair were not available. Inclusion of portable A/C units could increase emissions benefits, but numbers of portable units that are repaired or landfilled each year are unknown. Without knowledge of the numbers and age distributions of appliances in California, 2020 emissions reductions based on sector growth and transitional refrigerant/blowing agent use estimates were not possible. However, it is reasonable to assume that approximately 0.8 $MMTCO_2E$ reductions will be possible every year until refrigerators and freezers containing R-12 are gone, which will happen in large part by 2020.

Energy efficiency emissions avoidance in 2020 resulting from appliance retirement could not be calculated due to lack of data regarding age distribution of California appliances,

[5] The following assumptions were used: 1) 20 year lifetimes for refrigerators, 2) R-12 use in refrigerators stopped in 1995; from 1995 – 2005 HFC-134a was used, 3) in 2005, half of disposed refrigerators contain R-12 as the refrigerant and the other half contain HFC-134a as the refrigerant, 4) 13,000,000 refrigerator/freezers are disposed of annually in the US and 60% go to landfills or transfer stations, 5) the California population fraction was roughly 13% in 2005, 6) 100-year direct GWPs of 8100 and 1300 were used for R-12 and HFC-134a, respectively, 7) refrigerant masses of 0.23 kg/appliance and 0.16 kg/appliance for R-12 and HFC-134a, respectively, were obtained from USEPA (Dave Godwin, personal conversation, 2/07).

but again it is reasonable to assume that an additional 0.45 $MMTCO_2$ reduction is possible annually[6].

To summarize, by 2020, annual emission reductions of roughly 1.25 $MMTCO_2E$ are possible by recovering refrigerant from pre-2000 refrigerators and freezers, and by requiring upgrading to Energy Star or better appliances.

High-GWP Tracking/Reporting/Repair/Deposit Program: Staff believes that significant emission reductions may be realized through the proposed strategy; however, emission reductions cannot be estimated for this strategy, as there are no data to support emission avoidance calculations.

Total Reductions: The combined annual reductions possible with this group of strategies is 1.25 $MMTCO_2E$, which is a lower-bound estimate that does not include CFC-containing shipping containers, appliances that are upgraded rather than repaired, and the impacts of requiring reporting/repair/deposits for systems over a given CO2E threshold.

5. Estimated Costs/Economic Impacts and the Impacted Sectors/Entities

Refrigerant Recovery from Decommissioned Shipping Containers: Very little specific information on costs and economic impacts is known today. Per the federal regulation (40 CFR 82), refrigerant cannot be released to the atmosphere. Specialized equipment and certified technicians are required to properly carry out this measure. Equipment to recover the refrigerant may cost $5,000. The training cost for servicing certification is minimal. Both the equipment and the certified technicians are something that businesses should already have if they are in compliance with the existing federal regulation. It is possible that existing businesses in the air conditioning and refrigeration servicing industry may be able to handle recovering the refrigerant from the decommissioned refrigerated shipping containers. There will also be a requirement to remove or disable the decommissioned refrigeration unit, which should be a minimal cost. It is believed that as these shipping containers age, they get sold to smaller shipping businesses and these may bear the brunt of the measure for decommissioned containers. In addition, some of these units may be sold to restaurants and other businesses for increased refrigeration capacity. If the federal regulation is applied to in-use containers, then all segments of the business would be affected.

Residential Refrigeration Program: The US EPA states that because of reduced energy demand, appliance incentive/disposal programs cost about $0.04 on average to reduce each kWh of demand. This translates into about $\$63/MTCO_2$, which includes the incentives and credits given to upgrade older appliances[7].

---

[6] USEPA estimates that 700 kWh/year savings are possible by replacement of a 20 yr old refrigerator with a current energy star appliance; an emission factor of approximately 1.4 lbs CO2/kWh for gas-generated electricity was obtained from Carbon Dioxide Emissions from the Generation of Electric Power in the United States, DOE, 7/2000: http://tonto.eia.doe.gov/FTPROOT/environment/co2emiss00.pdf

[7] See above footnote.

The impacted sectors and entities would mostly be appliance salvagers/recyclers and individuals disposing pre-2000 appliances; however, with incentives and rebates, the cost associated with disposal and some of the cost of a new appliance is avoided.

The US EPA RAD program was started in 2006 and the success of the program has not been gauged yet, although it is anticipated that a mandatory program would be more effective.

High-GWP Tracking/Reporting/Repair/Deposit Program: Record-keeping, I/M and repair is already required for systems containing > 50 lbs of an ODS refrigerant; in SCAQMD, reporting is required for these systems in addition to record-keeping. Even those entities who are not yet keeping records for reporting purposes must still have some records of refrigerant/product purchases for resale and income tax purposes. Therefore, the costs associated with record-keeping and reporting are believed to be negligible.

I/M costs are not believed to be significant[8], but leak repair and/or high GWP GHG recovery for some processes may be expensive. The costs associated with I/M and leak repair cannot be estimated due to the large variety in numbers and types of equipment covered by this strategy. Costs associated with a deposit and return program are unknown, but will presumably be passed on to the consumer at the time of purchase.

6. Technical Feasibility

The technology required to remove refrigerants from shipping containers and appliances is feasible and commercially available. Automated refrigerant and foam removal from appliances is also technically feasible, and can be performed during scrap metal processing and recovery[9].

There are no anticipated technical feasibility issues for the tracking/reporting/repair/deposit program other than recovery of high-GWP GHGs for certain unknown, emissive processes.

7. Additional Considerations

---

[8] Presently, owners or operators of large RAC systems should maintain and repair their systems for optimal performance and reduced energy costs, so the incremental cost of the new rule is not expected to be significantly higher than current costs, unless leaks are going undetected and unrepaired. The costs to pay for yearly inspection and maintenance by certified technicians is not expected to be more than about $200 (based on one 8-hour workday by a HVAC technician at a rate of $22/hour in California:
http://www.payscale.com/research/US/Job=HVAC_Service_Technician/Hourly_Rate/by_State).

The incremental costs per system associated with an owner, operator, or HVAC technician/auditor filling out several short reporting forms is also expected to be less than $200 (see above).

[9] Guidance on the Recovery and Disposal of Controlled Substances Contained in Refrigerators and Freezers, SEPA, 2002:
http://www.sepa.org.uk/pdf/consultation/closed/2003/fridge/fridge_consultation.pdf

All Strategies: Ozone depleting substances (ODSs) were used in the past as refrigerants and foam-blowing agents; each of the strategies described above include ODSs as they exist in older refrigeration systems, appliances, and foams. Recovering and destroying ODSs from containers and appliances is a cost-effective way to reduce high-GWP gas emissions, and also reduces negative impacts on stratospheric ozone.

An enforcement component for the decommiossioned container and tracking/reporting/repair/deposit measures is anticipated, since these are regulatory measures rather than voluntary measures.

Refrigerant Recovery from Shipping Containers: Staff will perform a needs assessment to improve the current understanding of overall refrigerant leakage emissions and refrigerant banks for both active and decommissioned refrigerated shipping containers. This is particularly important for the major port areas of Los Angeles, Long Beach, and Oakland. If mitigation action is supported by the analysis, the measure should involve a program enforcing the existing provisions of the existing federal regulation, 40 CFR 82. A basic inventory is needed to determine the extent that refrigerant emissions are unaccounted for. In addition, end-of-life accounting for these different types of refrigerated containers needs to be explored.

Residential Refrigeration Program: The impacted sectors and entities would mostly be appliance salvagers/recyclers and possibly individuals disposing of foam-containing appliances, as recovery costs are expected to be passed along to the user.

California trade associations associated with Certified Appliance Recyclers and recyclers of scrap metals are unknown.

Coordination with the US EPA with respect to this regulation is ongoing. Further coordination with utilities participating in appliance trade-in programs is anticipated.

High-GWP Tracking/Reporting/Repair/Deposit Program: The affected entities will be owners/operators/purchasers/sellers of high-GWP GHGs and systems containing those chemicals, as well as contractors/technicians who install/repair such systems.

A partial list of trade associations possibly impacted, either positively or negatively, by the regulation follows: ARAP (described previously), the Air-Conditioning and Refrigeration Institute (ARI), American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), North American Technician Excellence (NATE), and many others unknown to staff (equipment trade associations, building trade associations, industrial chemical and consumer trade groups, semiconductor and other industrial process trade groups, etc.).

Coordination with the US EPA and SCAQMD with respect to this strategy would be ongoing.

8. **Division:** Research Division
Staff Lead: Whitney Leeman/Winston Potts
Section Manager: Michael Robert/Tao Huai
Branch Chief: Vacant/Alberto Ayala

9. References

American Association of Port Authorities (AAPA) web site: http://www.aapa-ports.org/home.cfm

Arthur D. Little, Inc., Global Comparative Analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire Protection Applications, Final Report to the Alliance for Responsible Atmospheric Policy, March 21, 2002.

David Godwin (USEPA), Marian Martin Van Pelt and Katrin Peterson (ICF Consulting), Modeling Emissions of High Global Warming Potential Gases from Ozone Depleting Substance Substitutes, 2003.

David Hatch, Carrier Transcold, personal communication, 5/07.

DOE, Carbon Dioxide Emissions from the Generation of Electric Power in the United States, DOE, 7/2000: http://tonto.eia.doe.gov/FTPROOT/environment/co2emiss00.pdf

EU (F-Gas Regulation), REGULATION (EC) No 842/2006 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL:
http://www.fluorocarbons.org/documents/library/Legislation/JO_L161_1_842_2006_Regulation.pdf

Federal Register, Section 608 of the CAAA, and USEPA's related website:
http://www.epa.gov/oar/caa/caa608.txt
http://www.epa.gov/ozone/title6/608/index.html

Harrison, R., "The Potential Impacts of Megaship Operations on Gulf Port," Center for Transportation Research, University of Texas

IPCC/TEAP, IPCC Special Report on Safeguarding the Ozone Layer and the Global Climate System, Issues related to Hydrofluorocarbons and Perfluorocarbons, 2005.

SEPA, Guidance on the Recovery and Disposal of Controlled Substances Contained in Refrigerators and Freezers, 2002:
http://www.sepa.org.uk/pdf/consultation/closed/2003/fridge/fridge_consultation.pdf

The Netherlands (STEK Regulation), "Order on leak-free refrigeration equipment", Dec. 18th 1994. SCAQMD, Rule 1415: http://www.aqmd.gov/rules/reg/reg14/r1415.pdf

USEPA, Draft Proposed Measures Arising from the IPCC/TEAP Special Report & its Supplement, by End-Use, Expert Workshop on IPCC/TEAP Special Report, July 2006.

USEPA, RAD program website: http://www.epa.gov/ozone/snap/emissions/radp.html

USEPA, U.S. High GWP Emissions 1990-2010: Inventories, Projections and Opportunities for Reductions, EPA 000-F-97-000, June 2001.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B03*
ID NUMBER:	*ARB 2-1 / EJAC-2*
TITLE:	*MANURE DIGESTER PROTOCOL FOR CALCULATING GREENHOUSE GAS MITIGATION*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 3rd quarter of 2008.

Specifically, staff recommends Board endorsement of the California Climate Action Registry (CCAR) manure digester protocol in order to promote voluntary greenhouse gas emissions reductions.

3. Early Action Description

Description of Protocol – The manure digester protocol provides methodologies for calculating reductions in the emissions of greenhouse gases resulting from the installation of a manure digester at an animal agricultural facility.

Technology Description – Manure digesters (also called biogas control systems) are systems which trap gaseous emissions from manure (primarily methane) and combust the gas. The trapping process is achieved by enclosing the manure, which often involves covering a manure lagoon with plastic or otherwise isolating the manure from the ambient environment. The combustion process occurs either by combusting the trapped methane biogas in an engine in order to generate electricity, or by venting and flaring the gases.

CCAR Protocol Development Process – CCAR began developing a protocol for calculating manure greenhouse gas emission back in April 2006. The protocol development process began with a first scoping meeting, included multiple working group meetings and document reviews, and included representatives from nearly every stakeholder group, including industry, government, academia, and the general public.

Need for Digester Protocol Endorsement – Although this protocol was adopted by CCAR, endorsement by the Board would send a clear signal that the ARB considers the protocols to be accurate and acceptable for voluntary GHG emissions reductions. To achieve this end, the ARB is initiating a process to continue discussions on the protocol by holding workshops to solicit comments on the protocol and to identify potential improvements. The ultimate goal is to present the protocol to our Board for endorsement as a voluntary greenhouse gas reduction measure.

Establishing a voluntary protocol can help incentivize the installation of manure digesters by legitimizing the technology and offering a pathway to quantify and verify the greenhouse gas benefits. Keeping this protocol a voluntary measure helps avoid premature technology mandates which could have significant cost and environmental drawbacks due to digesters currently being a costly, combustion-oriented technology.

4. Potential Emission Reductions

Digesters have the potential to provide a 50 percent reduction in GHG emissions resulting from manure storage (0.006 MMT CO2E per digester) as well provide electrical energy, offsetting the production of additional GHGs.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Cost per digester can range from the low hundreds of thousands of dollars to over a million dollars, depending on the digester type (covered lagoon, plug flow, etc.) and the amount of manure and biogas being processed. The captured biogas can be valuable if used for heating (water, animal housing) or combusted in an engine/ generator to produce electricity. Thus, the digester can reduce farm costs and may provide income if the gas or electricity is sold to other entities or back to the grid.

6. Technical Feasibility

Manure digesters are currently installed and operating at a limited number of farms in California.

7. Additional Considerations

Affected Entities: Farmers, energy companies, and any companies involved in the business of mitigating greenhouse gases (AgCert, CEERT, etc.)

Trade Associations: California Farm Bureau, Western United Dairymen, California Dairy Campaign.

Government Agencies Coordination: State Water Resources Control Board, local Air Pollution Control Districts, California Department of Food and Agriculture, California Climate Action Registry and others.

Proposed Board Hearing Date: September 2008

8. **Division:** Planning and Technical Support Division
   Staff Lead: Kevin Eslinger
   Section Manager: Dale Shimp
   Branch Chief: Richard Bode

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B04*
ID NUMBER:	*EJAC-3/ARB 2-12*
TITLE :	*REDUCE METHANE VENTING/LEAKS FROM OIL AND GAS SYSTEMS*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE AND CALIFORNIA AIR POLLUTION CONTROL OFFICERS ASSOCIATION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4th quarter of 2010.

Staff recommends an evaluation of the effectiveness of the existing district rules. Most likely these rules can be amended and readily adopted by the ARB for statewide implementation. Staff also proposes to investigate the feasibility of deploying innovative technologies and to improve management practices, including the stakeholder's proposal to implement energy efficiency measures that will further promote recycling of otherwise vented gases. These combined actions could potentially reduce methane emissions from both gas and oil systems by approximately 1.0 $MMTCO_2E$ in 2020[1].

3. Early Action Description

Emissions from natural gas systems are primarily methane gas. There are four major sources of methane emissions from the systems: production, processing, transmission, and distribution of natural gas. These emissions are process related, mostly stemming from normal operations, routine maintenance, and system upsets. Also, a relatively smaller amount of methane emissions results from oil systems.

Several air districts have adopted and implemented rules to reduce volatile organic compound (VOC) emissions from natural gas and crude oil production and processing facilities. These existing rules may also reduce methane emissions. In addition, there are several proven cost-effective technologies and management practices that would result in a significant reduction of methane emissions.

Staff will take the following approach to achieve the GHG reduction goal from oil and gas systems as stated in the 2006 CAT report:

- <u>Amend existing rules</u>[2,3]
  Form a working group that consists of ARB, district, and interested stakeholders to review the existing rules to identify potential methane emissions reduction measures.

- <u>Improve management practices</u>[4]
  Encourage districts with oil and gas systems under their jurisdiction to practice directed and more frequent inspections of compressor stations, gate stations, surface and storage facilities, transmission pipelines, and off-shore platforms.

- <u>Require the installation of cost-effective technologies</u>[4]
  Numerous technologies have been identified and proven in the U.S. EPA Natural Gas STAR program[5], a voluntary program partnership with the oil and natural gas industries, that will pay back investments in a short period of time through saleable gas savings. These technologies include replacement of high- with low-bleed pneumatic devices, installation of a flash tank on glycol dehydrators, retrofitting compressors to capture vented gas, and using an infrared aerial imaging camera to detect leaks, etc.

4. Potential Emission Reductions

Among the above identified strategies, staff estimated installation of new technologies will provide the greatest potential GHG emissions reduction, about 70 percent of the targeted goal of 1.0 $MMTCO_2E$ in 2020, while the rest will come from the existing rule amendments (~10 percent) and enforcement (~20 percent). Collectively, these strategies will provide a medium potential of GHG emissions reduction. They will also provide further emissions reduction of VOCs and toxics, with no incurred fuel penalty.

5. Estimated Costs / Economic Impacts and the Impacted Sectors/ Entities

ARB will develop this measure in partnership with CAPCOA. ARB will need additional resources to develop and enforce the new rule. CAPCOA may also require additional resources for complementary rulemaking to ensure that the rules are consistent.

As for the oil and gas industries, investment in new technologies will likely pay for itself through net fuel savings to offset the costs. As a result, staff believes that none of the proposed strategies will cause any potential disproportionate economic impacts on small businesses or environmental justice communities from increased utility rates.

6. Technical Feasibility

Natural Gas STAR partner companies have implemented most of the new technologies identified through a voluntary program established by the U.S. EPA when the natural gas prices were relatively low. These technologies were proven to be reliable and cost-effective. With the higher gas prices today, these technologies are even more cost-effective and attractive to the industry.

7. Additional Considerations

Staff has reviewed several districts' rules, addressing VOC emissions, that may have reduced methane emissions, and will work together with the districts to identify if any oil and gas industries have implemented fuel saving technologies. The ARB has legal authority to develop regulations and outreach programs to speed up the deployment of these technologies. However, staff believes a comprehensive and uniform regulation for this CAT strategy cannot be achieved in 18 months.

Affected Entities:

> Oil and gas industries, pipeline operators, gas processing and storage facilities, utility companies

Trade Associations:

> American Gas Association (AGA), Gas Processors Association (GPA), Interstate Natural Gas Association of America (INGAA), Kinder Morgan, Natural Gas Supply Association (NGSA), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric (SDG&E), Western States Petroleum Association (WSPA)

Government Agencies to coordinate with:

> Air Districts, California Air Pollution Control Officers Association (CAPCOA), California Energy Commission (CEC), California Public Utility Commission (CPUC), California State Land Commission (CSLC), Federal Energy Regulatory Commission (FERC), United States Environmental Protection Agency (U.S. EPA)

8. **Division:** Stationary Source Division
   Staff Lead: Win Setiawan
   Section Manager: Terrel Ferreira
   Branch Chief: Barbara Fry

9. References:

[1]*California Climate Leadership: Strategies to Reduce Global Warming Emissions*
July 2005, Tellus Institute.

[2]Stakeholders' comments to the ARB Proposed Early Action Measures to Reduce Greenhouse Gases, June 2007 Board Hearing, Los Angeles:
http://www.arb.ca.gov/lists/ab32eam07/67-ab32eam07-ws-5.pdf
http://www.arb.ca.gov/cc/ejac/ghg_eams_finalcommitteerec.pdf
http://www.arb.ca.gov/cc/ejac/ghg_eamcommitteelist.pdf

[3]*Various Air Districts Rules.*

[4]*U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions*, EPA 430-R-99-013, September 1999, U.S. EPA.

[5]*The EPA Natural Gas STAR Program*:
http://www.epa.gov/gasstar/

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B05*
ID NUMBER:	*EJAC-4/ARB 2-14*
TITLE:	*SMARTWAY TRUCK EFFICIENCY*
PROPONENT:	*2006 CAT REPORT AND STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this measure be reclassified as a discrete early action. The Board date for consideration of this item is anticipated in 4^{th} quarter of 2008.

The rationale for staff's recommendation is based on the commercial availability of a wide variety of technologies that improve fuel efficiency of heavy-duty vehicles that pay for themselves from fuel savings in a very short time. Although these technologies are commercially available, the trucking industry has been reluctant in using them due to the high initial capital investment and logistic issues related to using some of the technology at loading docks and other locations. However, staff believes these issues can be resolved. Therefore, staff recommends developing a regulatory program and evaluate whether financial assistance would be needed to help small businesses comply with the proposed regulation.

3. Early Action Description

The strategy would require existing trucks/trailers to be retrofitted with the best available fuel efficiency "SmartWay Transport"[1] and/or ARB approved technology. Technologies that improve fuel efficiency of trucks may include devices that reduce aerodynamic drag and rolling resistance. Aerodynamic drag may be reduced using devices such as cab roof fairings, cab side gap fairings, cab side skirts, and on the trailer side, trailer side skirts, gap fairings, and trailer tail. Rolling resistance may be reduced using single wide tires or low-rolling resistance tires and automatic tire inflation systems on both the tractor and the trailer.

---

[1] The United States Environmental Protection Agency (U.S. EPA) in collaboration with the freight industry has developed a voluntary program designed to increase energy efficiency while significantly reducing greenhouse gases and criteria pollutants. The program, known as the SmartWay Transport Partnership (SmartWay Transport), encourages trucking companies to use technologies that improve fuel economy and reduce emissions. The SmartWay Transport also designates highly fuel efficient and emission reduction technology packages as SmartWay Upgrade Kits which can be purchased at various SmartWay partner centers, dealerships, and service centers. (http://www.epa.gov/otaq/smartway/documents/420f07027.htm)

The requirements would apply to California and out-of-state registered Class 8 trucks (gross vehicle weight rating greater than 33,000 pounds) that travel to California. Most of the newer Class 8 combination trucks are long haul trucks for which technologies that reduce both aerodynamic drag and rolling resistance would be appropriate. The older model combination trucks are typically considered short haul trucks and thus spend considerably less time at highway speeds, reducing significantly any benefits associated with aerodynamic improvements since drag varies with the square of the vehicle speed. Thus, it would be most appropriate to require only rolling resistance improvements for these trucks. Straight trucks (trucks with an integrated cargo area) would likely be required to be equipped with devices that reduce aerodynamic drag as well as rolling resistance.

Staff's preliminary thinking is that the rule could be implemented through a phase-in schedule with 10 percent of the trucks and trailers meeting the requirements in 2010, 25 percent in 2011, 60 percent in 2012, and 100 percent in 2013. This rule should also require that new 2010 and subsequent trucks and trailers that are sold in or service California be "SmartWay" certified tractors and trailers[2].

Although the cost of retrofitting the trucks and trailers would eventually be recovered through fuel savings, the upfront investment capital needed to comply with the requirements may become a financial burden to businesses, especially small businesses and those that own multiple trailers per tractor. Therefore, staff recommends that an evaluation be conducted to determine whether a financial assistance program would be needed to help small businesses comply with the requirements.

4. Potential Emission Reductions

Potential GHG emission reductions were estimated for calendar years 2010 and 2020. For 2010, the scenario assumes that 10 percent of the existing 2009 and older model year (MY) trucks and tractor-trailer combinations and all 2010 MY trucks and tractor trailer combinations comply with the requirements. MYs 2006 to 2010 trucks were assumed to be long haul, MYs 2000 to 2005 medium haul, and MYs 1990 to 1999 short haul. Based on these assumptions and considering the total vehicle miles traveled both inside and outside of California, in 2010, the estimated GHG reductions could be up to 6 $MMTCO_2E$ of which about 7% would occur within California. Similarly in 2020, MYs 2016 to 2020 were assumed to be long haul, MYs 2010 to 2015 medium haul and MYs 2000 to 2009 as short haul trucks. Thus, the 2020 estimated GHG reductions could be up to 20 $MMTCO_2E$ of which about 11% would occur within California. Requiring compliance by California registered trucks and trailers would significantly reduce the

[2] U.S. EPA Certified SmartWay tractors and trailers are long haul tractors and trailers equipped with components that significantly reduce fuel consumption and emissions. The specifications for a U.S. EPA Certified SmartWay tractor include a model year 2007 and later engine, integrated cab-high roof fairings, cab side fairing gap reducers, tractor fuel-tank side fairings, aerodynamic bumper and mirrors, options for reducing extended engine idling, and options for low-rolling resistance tires. The specifications for a U.S. EPA Certified SmartWay trailer are side skirts, weight-saving technologies, gap reducers on the front of the trailer or trailer tail, and options for low resistance tires. For further information refer to:
http://www.epa.gov/smartway/documents/420f07033.htm .

GHG benefits of this rule to 0.2 and 1.3 MMT CO_2e in 2010 and 2020, respectively. The strategy is also expected to reduce emissions of criteria pollutants and especially emissions of oxides of nitrogen (NOx) since NOx is directly related to the tractive power requirements. Staff has not yet precisely quantified the reductions in emissions of criteria pollutants that may result from this strategy, but expect them to be on the order of 10 percent reduction for pollutants such as NOx, which are closely related to fuel use.

5. Estimated Costs/ Economic Impacts and the Impacted Sectors / Entities

Entities that may be affected by this strategy include the freight industry, trailer manufacturers, truck manufacturers, tire manufactures, businesses that own trailers to haul their freight into and out of California, and cab and trailer aerodynamic device manufacturers. The strategy is expected to provide cost savings to trucking businesses over the useful life of the tractor trailer combination by reducing fuel consumption. Assuming that add-on devices result in 13.9 percent fuel economy gain, the savings are approximately $5,400 per year for a truck with a baseline fuel economy of 6.1 miles per gallon and an average mileage accrual rate of approximately 90,000 miles per year, and a fuel cost of $3.00 per gallon. The cost of the add-on devices for a tractor trailer combination, which staff estimates to be approximately $12,000[3], can therefore be recovered within 2 to 2.5 years for a trailer-to-tractor-ratio of 1 and within 8 to 10 years for a trailer-to-tractor ratio of three[4]. Businesses that own only trailers and no tractors may not be able to recover the cost of retrofitting their trailers through fuel savings, and therefore, they may need to recover their investment either by paying less to haulers or by passing it to customers by increasing the cost of their merchandise.

6. Technical Feasibility

As indicated above, technologies that improve fuel economy of trucks are currently commercially available. Most of the tractors currently on the road are equipped with cab roof fairings and cab side fairing gap reducers. Trailer side skirts, trailer side fairing gap reducers, single wide tires and automatic tire inflation systems are also commercially available as SmartWay Upgrade Kits. However, there are some minor technical issues with these technologies that will need to be resolved. Retrofit of cab aerodynamics may or may not be possible depending on whether the tractor has factory installed reinforcements or not. Trailer side skirts may be problematic on some trailers where the side skirt interferes with access to equipment. Also, some fleets have expressed concern on trailer side skirts getting damaged when driving over road dips or bumps. The use of trailer tails is currently very limited due to functionality problems at loading docks. Currently, manufacturers of SmartWay devices are working on solutions to these problems and staff believes that these minor technical problems will be resolved by the time the rule is implemented or can be addressed in the development of this rule.

[3] The $12,000 estimate includes the cost for trailer aerodynamics (side skirts, gap fairings, and trailer tail), single wide tires and wheels for the tractor and trailer, automatic tire inflation system, and installation cost.

[4] The industry average trailer-to-tractor ratio is not exactly known. However, the most commonly cited numbers range between 2 to 3 trailers-per-tractor. The higher the number of trailers per tractor, the longer it takes to recover the cost from fuel savings.

7. Additional Considerations

This regulatory strategy is motivated primarily by its potential to reduce GHGs. All portions of this strategy can be accomplished under the authority granted by the California Global Warming Solutions Act of 2006, Assembly Bill 32 (AB 32). AB 32 provides the Air Resources Board (Board) with the authority to regulate sources of GHGs to achieve the maximum and cost-effective GHG emission reductions from these sources. The item can be taken to the Board by the 4th quarter of 2008 but requires additional resources.

Affected Entities:	Truck carriers, shipper carriers, trailer manufacturers, truck manufactures, truck and trailer aerodynamic device manufacturers, tire manufacturers, businesses that own trailers to haul their freight into and out of California
Trade Associations:	American Trucking Association, California Trucking Association, Truck Manufacturers Association, Truck Trailer Manufacturers Association, California Chamber of Commerce.

Government Agencies to coordinate with: None.

8. Division:	Mobile Source Control Division
Staff Lead:	Daniel Hawelti
Section Manager:	Stephan Lemieux
Branch Chief:	Michael Carter

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B06*
ID NUMBER: *EA 2-15*
TITLE: *COOL PAINTS FOR AUTOMOBILES*
PROPONENT: *EARLY ACTION REPORT OF APRIL 21, 2007 AND STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 2nd quarter of 2009.

3. Early Action Description

Cool paints are highly solar energy reflective coatings formulated with pigments that have low absorption (high reflectance) of sunlight. White is considered to reflect more sunlight than any other color. But while white paints reflect the visible light, they may or may not reflect the balance of the sunlight. The majority of solar energy is not in the visible range, therefore careful formulation of pigments can allow the reflectance of near-infrared (NIR) sunlight which contains about 52 percent of the solar energy, while maintaining visible light reflectance (i.e., perceived color). For vehicles, the more solar energy is reflected, the less the vehicle's interior will heat up when it is parked in the sun.

Cool paints have been demonstrated by the Society of Automotive Engineers as part of the Improved Mobile Air Conditioning Cooperative Research Program. They are technically feasible in the near-term for new vehicles. Researchers at Lawrence Berkeley National Laboratory (LBNL) tested various automotive paints formulated for use between 1992 and 2002[1]. Using a solar spectrometer, they determined the reflectance of both visible and NIR light wavelengths. Table 1 presents the reflectance of light (higher reflectance equals cooler paint). As expected, the dark colors tended to reflect less light; more light energy is absorbed. The potential of cool paints can be readily seen when examining the results for red paints, shown in **bold** on the table. The red paints ranged from a reflectance of 0.13, not much better than the black paint tested, to a high of 0.37. While that does not approach the 0.70 seen for the white vehicle, it is nearly three times more reflective than the worst performing red paint.

[1] These paints were all tested with a white primer.

Table 1. Reflectance of Vehicle Paints

Vehicle Paint Color	**Visible light**	**NIR**	**Total**
Black, 1998 Ford	0.04	0.04	0.04
Dark Grey, 1998 Dodge Intrepid	0.06	0.05	0.06
Grey Metallic, 1992 GM Buick	0.21	0.25	0.22
Silver, 1992 Ford Escort	0.49	0.54	0.50
Gold Metallic, 1998 Ford Taurus	0.46	0.56	0.49
Light Blue Metallic, 1994 Honda Accord	0.33	0.44	0.39
Blue Metallic, 2001 GM	0.06	0.13	0.10
Green, 1995 Chevy Camero	0.07	0.08	0.08
Red, Chevy	0.08	0.18	**0.13**
Red, 2000 Ford Escort	0.14	0.50	**0.33**
Red, 2002 Chevy Avalanche	0.15	0.35	**0.25**
Red, 1993 Chevy S10 Blazer	0.15	0.57	**0.37**
White, 1997 GM Park Avenue	0.70	0.77	0.70

4. Potential Emission Reductions

The concept behind this proposed action item is that the use of cool paints would reduce the solar heat gain in a vehicle parked in the sun. A cooler interior would provide drivers with less need to activate the air conditioner (A/C).

LBNL researchers have investigated the CO_2 reduction that would result from a 5^oF reduction in vehicle temperature at start up.[2] LBNL's Dr. Hashem Akbari estimates that such a reduction in temperatures, applied to the light duty vehicle fleet in California, would reduce CO_2 emissions from A/C use by about 25 percent, reducing current CO_2 estimates of A/C related emissions of 10.2 million metric tons per year (MT/yr) to 7.8 MT/yr, a 2.4 MT/yr reduction.[3]

Staff also requested input from Dr. John Rugh, National Renewable Energy Laboratory, on the probability of A/C use for a given reduction in temperatures. Dr. Rugh is currently involved in a global effort led by the Society of Automotive Engineers (SAE) to come up with an agreed upon method to determine life cycle climate performance. This effort is known as SAE's Improved Mobile Air Conditioning Cooperative Research Program. Dr. Rugh provided a draft analysis from Phoenix, showing the percent of time the A/C is in use for given ambient temperature ranges. As would be expected, at low ambient

[2] A 5^oF reduction in interior temperature has been measured by Toyota when changing from a metallic blue paint with a solar reflectivity of 10 percent to one with a reflectivity of 20 percent. Table 1 shows NIR reflectivity of 0.77 for white paint. This could be applicable to all paints, and could probably be improved to reach values closer to 100 percent reflectivity. Therefore, even the metallic blue paint should be able to achieve a reflectivity of at least 50 percent. Thus, the anticipated CO_2 reduction should be conservative.

[3] Literature on cool paints and window glazings typically model the potential for downsizing the A/C unit that exists due to measured reductions in soak temperature. Statements of the amount of downsizing feasible for equivalent cooling times are typically followed by an associated reduction in CO2 emissions. Dr. Akbari presumes improvements in emissions would result whether the A/C unit was downsized or the existing unit was simply used less frequently.

temperatures, very little A/C is used: As temperatures increase to around 18^oC, A/C use begins to increase. Use continues to increase steadily until the A/C is in use nearly 100 percent of the time, around 38^oC. During the rising portion of the curve, A/C use increases about 5 percent per ^oC. If it is presumed that increased ambient temperatures are associated with increased soak temperatures, it would be logical to correlate a reduction in soak temperature in the midsection of the graph with a reduction in A/C use. Thus, a reduction in temperature of about 2.7^oC (5^oF), as seen in the Toyota test, would be expected to result in 14 percent less A/C use when ambient temperatures are in the rising portion of the curve. Staff applied that figure to the methodology developed by Dr. Akbari, and found a predicted reduction in CO_2 emission from a 2.7^oC reduction in temperature of 2.1 MT/yr, which is comparable to the estimate presented by Dr. Akbari.

The following bullets summarize the issue:

- Slightly over half of all solar energy is in the form of NIR radiation, which is not visible to the naked eye. Cool paints use pigments that have low absorptance of NIR while maintaining a variety of visible colors.
- The benefits of cool paints include:
  - Lower external surface temperatures, reducing burn hazard and the transfer of heat to the interior of the vehicle.
  - Lower interior temperatures, resulting in greater driver comfort and potentially reduced A/C demand.
  - Potential to reduce size of air conditioner. According to LBNL staff, a vehicle's A/C is currently designed to cool a black vehicle parked for 4 hours in the summer sun in Phoenix within a set time period. If that vehicle is painted with cool black paint, the soak temperature would be reduced and the A/C load reduced. Downsizing the A/C would allow it to operate at more efficient loads while maintaining desired interior temperatures.
  - Reduced use of and/or downsizing of an A/C would result in reduced GHG emissions. Analyses indicate a reduction of 2.1 to 2.4 MT/yr CO_2e could be achieved for the light duty fleet with a relatively small improvement in solar reflectivity. Additional reductions for the medium and heavy duty fleets would likely increase this figure.
  - Possible increased lifespan of exterior paint, interior plastics and other materials

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

There are few disbenefits to this technology beyond a slight increase in coating cost. This may be more than offset by reduced A/C use or A/C downsizing, if this occurs. Cool paints currently cost about $10 more per vehicle than traditional paints. Literature indicates these paints are applied with standard equipment and methods. The small increased cost could be more than offset by a downsized A/C unit, and would be offset by improvements in operational costs due to reduced A/C use. In addition, the increased comfort should be of value to many consumers.

These paints would have the most benefit if used in conjunction with other technologies (e.g., window glazing, passive ventilation) to reduce a vehicle's interior temperatures. Therefore with the development of this rulemaking, staff will also evaluate other technologies that will reduce the heat load on the vehicle's A/C and determine if it would be appropriate to include these technologies in the "cool paints" proposal.

6. Other Considerations:

Cool paints can be formulated with existing paint formulations such that supply should not be an issue. BASF, DuPont, Sherwin Williams, many other paint manufacturers do have cool versions of at least some paints developed. Cool paints do not limit consumer choice of color. Cool paints use pigments that have low absorbance of the non-visible spectrum while maintaining the same variety of visible colors that consumers demand. Presently, cost and car maker acceptance appear to be the only show-stoppers for the use of cool paints and other complimentary cool car technologies.

An evaluation should be done to determine if the reformulated "cool paint" will result in an increased toxic exposure risk during the paint application process and disposal. Staff believes this exposure risk should be minimal due to the fact that research thus far, shows that "cool paints" can be formulated using existing pigments; however it is an issue that needs to addressed during the formal rulemaking process.

7. Division:	Mobile Source Control Division
Staff Lead:	Marijke Bekken
Section Manager:	Sharon Lemieux
Branch Chief:	Michael Carter

8. References:

Akbari, Hashem, "Coatings for Cool Vehicles" Presentation, March 16, 2007

Lawrence Berkeley National Laboratory, Heat Island Group, http://CoolColors.LBL.gov

Rugh, J., "Assessing the Vehicle Level and National A/C Fuel Use Impact of Advanced Climate Control Technologies," International Energy Agency Workshop – Cooling Cars with Less Fuel, Paris, France, Oct. 23, 2006.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B07*
ID NUMBER:	*EJAC-14/SCAQMD-6/EA 2-16/ARB A-14*
TITLE:	*GREEN PORTS*
PROPONENT:	*2006 CAT REPORT AND STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this measure be reclassified as a discrete early action. The Board date for consideration of this item is anticipated in 1st quarter of 2008.

Staff proposes to present the draft regulation to the Board as a measure to reduce nitrogen oxides (NO_x) and diesel particular (PM) emissions and to quantify the associated (carbon dioxide) CO_2 emission reductions. By focusing on NO_x and PM reductions, staff will address the local and regional health impacts of ships docked in California's ports, including any disproportionate impacts those emissions may have on surrounding communities.

3. Early Action Description

This early action allows docked ships to shut off their auxiliary engines by plugging into shoreside electrical outlets or other technologies. The Air Resources Board identified port electrification as a strategy to reduce the emissions of nitrogen oxides (NO_x) and diesel particulate matter (PM) when the Board approved the Goods Movement Emission Reduction Plan in April 2006. Furthermore, the Climate Action Team (CAT) recommended port electrification as a greenhouse gas (GHG) emission reduction strategy in 2006.

While a ship is docked at a berth, or "hotelled," it continuously runs at least one auxiliary engine to power lighting, ventilation, pumps, communication, and other onboard equipment. Ships can hotel for several hours or several days.

Port electrification provides an alternative source of power for these ships while they are docked. The ships can use cables to receive electricity from the shore, thereby allowing them to shut off their auxiliary engines, reducing emissions of air pollutants. Although the generation of electricity creates emissions—typically from power plants located elsewhere—these emissions are much less than those from the auxiliary engines located on the ships. Port electrification of a ship can reduce its emissions of NO_x and diesel PM by more than 90 percent. Greenhouse gas (GHG) emissions, as carbon dioxide (CO_2), are also reduced, depending on the source of electricity provided to the berth.

To be an attractive candidate for shore electrification, a ship must visit a California port frequently, spend a sufficient number of hours in berth, and have an ample power demand while docked. The ship categories that typically meet these criteria are container ships, passenger ships, and refrigerated cargo ships. (Passenger ships, although in port for only about 10 hours, visit frequently and have tremendous power needs.) Ship categories that are not attractive candidates include bulk cargo ships, vehicle carriers, and most tankers. The ports that receive numerous calls by container ships, passenger ships, and refrigerated cargo ships—and therefore the ports most likely to employ port electrification—are Los Angeles, Long Beach, San Diego, Oakland, San Francisco, and Hueneme.

ARB staff is currently working with ports, ship operators, utility companies, local air districts, and other interested stakeholders to develop a regulation to reduce emissions from ships while docked. Although the proposed regulation will allow alternative technologies to reduce emissions, the key component of the regulation will be port electrification. Staff expects to take the proposed regulation to the Board for its consideration by the end of 2007.

4. Potential Emission Reductions

ARB staff is pursuing the port electrification strategy as a measure to reduce NO_x and diesel PM emissions. This strategy was identified in the Goods Movement Emissions Reduction Plan (GMERP), approved by the Board in April 2006. The reduction of these pollutants is essential for protecting public health near California's ports and for the South Coast Air Basin to eventually achieve and maintain health-based ambient air quality standards for ozone and fine particulate matter. The reduction of CO_2 is a co-benefit of the proposed at-berth emission reduction regulation.

Although the proposed regulation is not yet fully developed, staff estimates that the regulation may result in the following emission reductions:

Pollutant	**2015**	**2020**
NO_x (Tons)	15,000	19,000
Diesel PM (Tons)	400	500
CO_2 (Million Metric Tons)	0.3	0.5

Staff expects port electrification to achieve emission reductions in 2010—largely due to the commitments of the Port of Los Angeles and the Port of Long Beach through their Clean Air Action Plan—however, the emission reductions from the proposed regulation will not be substantial until after 2010.

The potential CO_2 emission reductions of port electrification are dependent on the source of the electricity provided to the port. If the electricity portfolio of the utility company has a significant portion of renewable sources, such as wind, solar, or biomass, then the CO_2 reductions may be substantial. Similarly, if the portfolio contains sources of electricity that generate considerable amounts of CO_2—say, out-of-state coal-fired plants—then the potential CO_2 emissions would be diminished.

For the purpose of this analysis, ARB staff used a CO_2 emission factor of 0.25 MMT CO_2/MW-hr for the electrical grid and 0.69 MMT CO_2/MW-hr for the auxiliary engines. Staff will consider utility-specific CO_2 emissions and marginal electricity generation CO_2 emissions (typically combined-cycle gas turbines) as the development of the regulation proceeds.

As mentioned earlier, the proposed regulation will allow alternative technologies to achieve required emission reductions. These alternatives may include ship-side technologies, such as post-combustion devices, alternative fuels, or cleaner engines, or shore-side technologies, including distributed generation or emission-capture-and treatment devices. These technologies will probably be less effective in reducing GHG emissions when compared to port electrification; however, their overall deployment and impact are uncertain.

As a GHG emission reduction strategy, port electrification has the potential to reduce CO2 emissions on the order of 0.3 to 0.5 MMTCO_2 per year. This estimate does not consider the climate benefit associated with reduction of black carbon, a component of diesel PM.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Staff estimates that port electrification, as currently proposed, will cost more than $1.2 billion, roughly one-third of that cost borne by the ports and terminals, two-thirds by the ship operators.

The growth in port activity—especially the substantial increase in containers expected to be handled by the ports and the projected surge in cruise-ship vacations—will have a significant impact on the number of ships that must be built or retrofitted to accommodate port electrification. ARB staff estimates the number of ships to be affected by the proposed regulation as:

Ships Affected	**2015**	**2020**
Container	500	1,200
Passenger	76	110
Refrigerated Cargo	10	25

In addition to the recovery of that capital expenditure, annual operating expenses will include labor costs necessary to connect and disconnect the ships to shore power and the cost of the electricity itself. Fuel savings realized by shutting down the auxiliary engines will help offset the electricity costs.

Staff estimates that the annual costs of port electrification are as follows:

Annual Costs	**2015**	**2020**
Capital Costs	$148 million	$250 million
Operating Costs	$42 million	$ 75 million
Total	**$190 million**	**$325 million**

As mentioned above, port electrification is considered foremost a measure to reduce NO_x and diesel PM emissions with GHG emission reductions being a co-benefit. The cost effectiveness of port electrification for 2020 is estimated at $17,000/ ton for NO_x or $640,000/ ton for PM. These values represent the cost of the regulation completely allocated to either NOx or diesel PM; a sharing of the total costs between these two pollutants would further enhance their cost effectiveness.

If NO_x and diesel PM emission reductions were not considered, and port electrification were considered solely as a GHG emission reduction measure, the cost effectiveness in 2020 would be $650/MT CO_2.

Staff proposes to present the draft regulation to the Board as a measure to reduce NO_x and diesel PM and to quantify the associated co-benefit of CO_2 emission reductions. By focusing on NO_x and PM reductions, staff will address the local and regional health impacts of ships docked in California's ports, including any disproportionate impacts those emissions may have on surrounding communities.

6. Technical Feasibility

Port electrification is a proven technology. The U.S. Navy has been employing it worldwide for decades. Princess Cruise Lines currently uses port electrification in Juneau, AK and Seattle, WA, as does China Shipping at the Port of Los Angeles (POLA). The NYK Atlas has recently plugged in at POLA, and British Petroleum is expected to utilize port electrification by the end of the year at the Port of Long Beach for two of its diesel-electric tankers.

Although technically feasible, port electrification is not without its challenges, including the availability of electricity, the standardization of electrical hookups, and sufficient visits to electrified berths by retrofitted ships to make the emissions reductions cost-effective. Staff has been discussing the necessary electrical infrastructure and supply with the major ports and utility companies. The International Maritime Organization (IMO) is considering standard electrical connections for port electrification, and several California ports and other organizations are participating in that effort.

7. Additional Considerations

California will be the first state to require port electrification, or its equivalent, if the Board adopts a proposed regulation within the next six months. Current port electrification projects within California and the United States have been required on a case-by-case basis.

The requirement to reduce emissions from ships while docked at California ports is clearly within the jurisdiction of the Air Resources Board. Port electrification has been identified as a strategy to reduce NO_x and diesel PM in the Goods Movement Emission Reduction Plan and as a GHG emission reduction strategy by the CAT. Staff will bring a proposed regulation to the Board within the next six months.

8. Division: Stationary Source Division
Staff Lead: Grant Chin

Section Manager: Mike Waugh
Branch Chief: Mike Tollstrup

9. References:

Draft Evaluation of Cold-Ironing Ocean-Going Vessels at California Ports (ARB, March 2006)

Documentation to Climate Action Team, December 2006

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Action Strategy Name and Proponent

SUMMARY #	*B08*
ID NUMBER:	*EJAC-7/ARB 2-17*
TITLE:	*TRANSPORT REFRIGERATION UNITS, ELECTRIC STANDBY*
PROPONENT:	*2006 CAT REPORT AND ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This strategy was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this strategy is recommended. Costs for this strategy are high and new information indicates costs may be 30 to 50 percent higher than originally estimated. An extensive amount of coordination with industry remains to be completed before any regulatory action can proceed. This is due to a variety of factors, including the lack of industry standards for electric power use on transport refrigeration units (TRUs). For example, more than four optional voltages are used, along with both single phase and 3-phase frequencies, and many electric power plug configurations are in use (see Part 7 for more information). Therefore, a Board hearing date is not indicated.

3. Description

Transport refrigeration units are refrigeration systems powered by integral internal combustion engines designed to control the environment of temperature sensitive products that are transported in trucks, trailers, shipping containers, and railcars. In 2004, the TRU Airborne Toxic Control Measure (ATCM) was adopted to reduce diesel particulate matter (PM) emissions from TRU engines. ARB staff is currently implementing this ATCM. As conceived, this strategy would go beyond current ATCM requirements with a regulatory action to require that no TRU-equipped trucks, trailers, shipping containers, or railcars that are used at a large distribution center for outbound loads would be allowed to be powered by internal combustion engines for more than 30 minutes in a 24-hour period.

An optional component of this strategy would prohibit the use of internal-combustion engine-powered TRUs on trucks, trailers, shipping containers, and railcars from being used for extended cold storage at California distribution centers, grocery stores, and elsewhere. This practice occurs during the 4-to-6 week period before all of the major holidays because distribution center cold storage warehouse capacity is exceeded at about 30 percent of the distribution facilities and at an unknown number of grocery stores.

4. Potential Emission Reductions

For this strategy, staff estimates a reduction of 3.4 to 4.3 million gallons of diesel fuel used per year (with 51 to 64 GWh of new electricity use); the optional component (extended cold storage prohibition) would result in an additional reduction of 1.7 million gallons of diesel fuel used per year (with 26 GWh new electricity use). This strategy would also provide emission reduction co-benefits due to reduced diesel engine operating times; therefore, emissions of ozone precursors and diesel PM particulates would also be reduced. However, ARB staff estimates only about 0.04 million metric tons per year of CO_2 reductions could be achieved (0.45 million metric tons total by 2020).

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Capital costs are estimated to be $105 million for the first year and $3.1 to $3.6 million per year thereafter. The optional component would require an additional one-time capital cost of $44 million. New information indicates capital costs may be 30 to 50 percent higher than these early estimates. Without including these potential increases, inflation or discount factors, ARB staff estimates rough annual costs at $16.7 million per year (total accrued costs, with savings, would be approximately $167 million in 2020). Staff is still working on refining cost and is not able to provide a cost-effectiveness estimate at this time.

6. Technical Feasibility

Compliance is a critical issue which will most likely require the use of various technologies in order to ensure that adequate enforcement of the regulation occurs. Technologies exist that could be applied toward automated compliance assurance and reporting systems, but it may take several years to develop and test the reliability of such systems such that they could be used for this application. Additional regulatory action may also be necessary to ensure these compliance assurance systems provide an enforceable reporting mechanism.

7. Additional Considerations

Industry standards need to be developed and adopted to address compatibility issues, plug types, and configurations. Although electric standby (E/S) technology is available for some TRU models, less than one percent of trailer TRUs are currently equipped with E/S and retrofitting with E/S is extremely expensive and has never been attempted. Extensive design and development work is needed before E/S use could be required. Most existing TRU models will need to be redesigned to use smaller, more efficient refrigeration compressors or to use larger, more powerful electric motors to provide enough capacity for quick initial trailer cool-down prior to loading perishable goods. Current E/S designs use under-powered electric motors that are intended only to maintain a temperature set point after the diesel engine completes the initial chill down. Additionally, further investigation on the feasibility of prohibiting the use of diesel-powered TRUs for extended cold storage is needed as it may require a significant change in business practices and have unforeseen economic impacts.

8. **Division:** Stationary Source Division
Staff Lead: Rod Hill
Section Manager: Richard Boyd
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B09*
ID NUMBER:	*EJAC-9/ARB 2-19*
TITLE:	*TRUCK STOP ELECTRIFICATION WITH INCENTIVES FOR TRUCKERS*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is waiting to be determinate.

Staff recommends that ARB considers an incentive-based strategy to expedite a comprehensive deployment of on-shore electric power infrastructure to eliminate idling emissions from heavy-duty trucks. This incentive program must consider the existing requirements of the idling regulations in order to design an approach that would yield surplus emissions through the use of financial incentives. The incentives could be structured to pay a portion of the plug-in usage fee either to the truckers or to the technology vendors. The advantage of this strategy would be the elimination (exclusive of power plant emissions) of greenhouse gas and criteria pollutant emissions resulting from truck idling activities. This approach would also provide an alternative for the trucking industry to not just comply with the idling requirements, but would allow them to go beyond those requirements to achieve zero emission through the use of financial incentives. The disadvantage of this strategy would be the high costs to obtain relatively small incremental benefits since existing regulations have already established very low emission thresholds for this source category.

3. Early Action Description

This strategy would require truck stops to install electrical power infrastructure (i.e., on-shore electrical power) to reduce heavy-duty trucks idling emissions, perhaps through the use of financial incentives. On-shore electric power involves the electrification of truck parking spaces to provide power for heating, cooling and on-board truck accessories. Affected entities of this strategy include owners and/or operators of heavy-duty trucks, truck stops owners and technology vendors.

Heavy-duty trucks idle their engines an estimated 6 hours per day, resulting in emissions of criteria pollutants and greenhouse gases. These emissions could be eliminated with the proposed electrification strategy as a result of eliminating the combustion of diesel fuel from either the truck engine or the auxiliary power unit (APU) engine. The ARB has already adopted regulations limiting the idling time of heavy-duty trucks unless the truck is installed with appropriate low-emission technology. Starting in 2008, all trucks must comply with a 5-minute idling limit unless it has a certified APU coupled with a PM trap. Engine manufacturers also have the option of certifying model year 2008 and newer main truck engines to a low idling NOx emission level of 30 grams per hour (ARB, 2005). Since the existing regulations have already set limits and requirements on truck idling activities, this proposed strategy would provide additional emission reductions beyond those regulations by eliminating the emissions resulting from operation of the APU, or from low-idling emission engines.

Currently, there are already two on-shore power technologies that have been commercially established and have been used to eliminate truck idling emissions. The two technologies are commonly referred to as on-board power infrastructure and off-board infrastructure technologies.

On-board power infrastructure provides trucks with 110-volt AC electrical power at truck stops to run the air conditioning, heating and on-board accessories. This would require truck stops to be equipped with electrical outlets throughout the parking spaces and trucks need to be equipped or retrofitted with inverter/chargers, electrical power connections and electrically driven heating and air conditioning units. The drawbacks of this approach include the high initial infrastructure cost, cost for equipment add-ons to trucks, and its availability, which is limited to where the infrastructure is installed. The aftermarket cost for add-ons and installation is about $4,000 per truck and power infrastructure installation is about $3,500 to $6,000 per truck parking space depending on the number of power pedestals installed (Perrot, et al, 2004).

Off-board power infrastructure provides 110-volt AC electrical power through an externally installed heating and air conditioning unit, as well as hook-ups for basic telephone, internet and television services at each truck parking space. The unit is connected to the truck through a console installed to the truck window using a template insert. The console contains all the necessary connections and controls, including a card reader for the billing system. Currently the usage fee for basic services range from $1.25 to $1.50 per hour. The off-board power infrastructure installation cost is approximately $12,000 to $20,000 per parking space depending on the number of parking spaces installed (Antares, 2005). The advantage of this system is that the truck does not need to be modified with any alternative cab comfort technology, resulting in immediate benefits to the truck owner using the service through reduced fuel consumption and maintenance savings.

This strategy could be crafted as a regulation requiring all truck stops to install electric infrastructure that could be used by truckers to eliminate truck engine idling. To be effective, that regulation would also need to require the truckers to use the electric infrastructure for their idling needs instead of idling the truck engine or using the APU. However, since ARB already has existing idling regulations, one of which has already been implemented and the other will become effective in January 2008, it will be challenging to develop another regulation on top of the existing idling regulation. A less contentious approach would be through an incentive-based program to spur the installation of the appropriate electric infrastructure that would allow truckers the option to “plug in” when they park at these truck stops.

ARB has already had direct experience in implementing an incentive-based on-shore power infrastructure program. ARB executed a grant with IdleAire, a company that developed an off-board power infrastructure technology, to assist in the installation and operation of off-board power infrastructure at various truck stops located in the San Joaquin Valley. The grant, totaling $1,334,536, was used to pay for usage ($1.50 per hour) of the IdleAire device at the 415 parking spaces at six truck stops that are spread throughout the San Joaquin Valley. The South Coast Air Quality Management District (SCAQMD) has also funded IdleAire projects in the South Coast with funding from the Carl Moyer Program and the U.S. EPA. In addition to paying for usage, at a rate of $3.94 per hour, the SCAQMD program also pays for a portion of the installation cost ($8,726 per unit) of the IdleAire power unit.

4. Potential Emission Reductions

The existing truck idling regulation limits idling time from heavy-duty trucks to 5 minutes unless the truck is equipped with an APU coupled with a particulate trap or, alternately, unless the truck is a 2008 and later model year that is certified to the low idling NOx emission standard of 30 grams per hour. Because of this requirement, the NOx idling emission rate of 30 grams per hour was used as the baseline emission level. Since existing idling regulations do not specify optional idling emission rates for pollutants other than NOx emissions, the truck baseline idling emission levels for other pollutants such as HC, PM, and CO2 were established using EMFAC2002 idling emission rates. The surplus emission reductions are calculated as going from these baseline levels to a zero emission level for each truck stop parking space that is electrified.

Based on data from Report to Congress of Adequacy of Parking Facilities, there is currently about 7,500 spaces at truck stops and 1,300 spaces in Caltrans public rest areas. Currently, about 900 parking spaces at truck stops are installed with electric power infrastructure, resulting in an estimated 2010 annual reduction of about 55,000 tons of CO2 per year (0.055 MMTCO2E). If the remaining truck stop parking spaces are electrified, an additional annual reduction of about 405,000 tons of CO2 (0.4 MMTCO2E) would result. Depending on the expected growth of available parking spaces at truck stops, the 2020 emission benefits could be adjusted accordingly. The expected CO2 emission reduction from this strategy, if fully implemented, could be on the order of >0.1 to 1.0 MMTCO2E. Emission reductions of criteria pollutants (HC, NOx, and PM) are estimated to be about 530, 1,300, and 120 tons per year, respectively, in 2010.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Given the cost of the existing on-shore electric power infrastructure technology and the expected baseline emission rates, it is estimated that the cost to reduce CO2 emissions to range from a low of about $135 per metric ton to a high of about $359 per metric ton. There are about 6,600 parking spaces at truck stops and about 1,300 parking spaces in Caltrans public rest areas that are currently do not have electric power infrastructure, for a total of about 7,900 truck non-electrified parking spaces. Assuming the cost of on-shore power infrastructure to range from $7,500 to $20,000, including the cost of on-truck equipment in the case of the on-board power infrastructure technology, the total cost to electrify all 6,600 parking spaces at truck stops would be about $49,500,000 to $132,000,000. If the 1,300 parking spaces at Caltrans public rest areas are also to be installed with on-shore electric power infrastructure, it would cost an additional $9,750,000 to $26,000,000.

A requirement for an on-shore electric power infrastructure would impact truck stop owners, truck drivers, and technology vendors. The economic burden on truck stop owners would depend on how they structured their approach towards establishing the required infrastructure. They could purchase the equipment and have it installed at their facilities, or they could opt to lease the parking spaces to technology vendors for them to install the equipment. The cost to truckers could range from the cost to install the necessary equipment on their trucks in the case of an on-board technology to simply just paying for the hourly cost of plugging in when they use the facility. The cost to technology vendors would be the cost to manufacture, install, and operate the power infrastructure.

6. Technical Feasibility

On-shore electric power infrastructure is an established, proven commercial technology. This technology is currently being deployed at various truck stops throughout the country. In California, approximately 900 truck stop parking spaces already have on-shore electric power infrastructure. The main obstacle to more widespread deployment of this technology appears to be the relatively high initial cost of installing the necessary infrastructure.

7. Additional Considerations

Additional analysis is needed before deciding on an implementation path. It is possible that other jurisdictions have taken this action as an incentive program. Also, this strategy clearly falls under ARB jurisdiction and authority as idling limits have been adopted. Although an incentive program appears to be the best option, a regulation could be developed in the next 18 months, making the strategy a discrete early action.

Affected Entities: Truck stop owners, truck drivers, technology vendors

Trade Associations: Trucking associations, utilities companies

Government Agencies to coordinate with: Local air districts, local governments regarding permitting requirements

8. Division: Mobile Source Control Division
Staff Lead: Bob Nguyen
Section Manager: John Kato
Branch Chief: Jack Kitowski

9. References:

ARB, Notice of Public Hearing to Consider Requirements to Reduce Idling Emissions from New and In-Use Trucks, Beginning in 2008, Sacramento, September 1, 2005

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B10*
ID NUMBER:	*EA 2-20*
TITLE:	*TIRE PRESSURE PROGRAM*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this measure be reclassified as a discrete early action. The Board date for consideration of this item is anticipated in 1st quarter of 2009.

Maintaining a vehicle's tire pressure to the manufacturer's recommended specifications is a practical strategy to achieving early greenhouse gas (GHG) emission reductions. Current Federal law requires auto manufacturers to install tire pressure monitoring systems in all new vehicles beginning September 1, 2007. Staff recommends that the ARB investigate strategies to ensure that the tire pressures in older vehicles are also monitored, as well as requiring the tires to be checked and inflated at regular service intervals. One potential strategy would be to require all vehicle service facilities, such as, dealerships, maintenance garages, and smog check stations, to check and inflate tires.

Staff also recommends that the feasibility of conducting an extensive outreach program be investigated. The outreach program could entail placards being placed above each fueling dispenser to encourage drivers to properly maintain their tires each month. The placards would highlight the amount of money consumers could save as a result of lower fuel consumption, as well as, how each consumer is doing their part to help prevent climate change.

3. Early Action Description

According to the National Highway Traffic Safety Administration (NHTSA), 74% of all vehicles have at least one significantly under inflated tire[1]. The U.S. Department of Energy (DOE), California Energy Commission (CEC), and NHTSA, state that every 1 pound per square inch (PSI) drop in tire pressure equals an approximate 0.4% drop in a vehicle's gas mileage. Establishing a program to monitor and correct vehicle tire pressure could save Californians a minimum of 61 million gallons of fuel, which equates to 0.54 MMT of CO_2 emissions in 2010 (first year of implementation) and 22.5 million gallons of fuel and 0.20 MMT of CO_2 emissions in 2020. Potential savings from a program that was 100 percent effective in ensuring proper tire inflation are on the order of 96 millions gallons of fuel saved in 2010.

4. Potential Emission Reductions

The GHG emission benefit of this program is associated with the reduction in gallons of fuel consumed by California drivers. The reduction in gallons of fuel consumed is based upon 10 million vehicles visiting a repair facility at least once a year and having their tires checked and inflated to the manufacturer's recommended pressure[2]. Approximately 74 percent of vehicles in California have under inflated tires, of which, 27 percent have at least one tire severely under inflated (25 percent or more of the manufacturer's recommended pressure)[1]. On average, a vehicle tire loses approximately 1 PSI per month[2]. For every loss of 1 PSI in tire pressure, a corresponding loss in fuel economy of 0.4% can be expected[2].

It is estimated that Californians will consume approximately 14.1 billion gallons of gasoline in 2010 and 16.2 billion gallons in 2020[3]. In 2010 (first year of implementation), the predicted reduction in the consumption of fuel is 61 million gallons which equates to 0.54 MMT of CO_2. This is based on 27 percent of vehicles having at least one tire severely under-inflated, 47 percent having tires under inflated by 1 PSI, and 26 percent having the correct pressure[1]. In 2020, emissions reductions are expected to be lower due to the recommended strategy and outreach programs and the federal requirement for tire pressure monitoring systems in all new vehicles. The reduction in gallons of fuel consumed will be approximately 22.5 million gallons which equals 0.20 MMT of CO_2.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Costs associated with this program include public outreach and education, equipment costs such as compressors and accessories, and labor. One study suggested the labor rate to check and inflate tires will be approximately $3.75 per vehicle[2]. In addition, some vehicle repair facilities may be required to purchase an air compressor and accessories at an approximate cost of $500[4].

Retrofit technologies exist that can monitor tire pressure at costs ranging from $20 to $600 depending on the system and installation variables (i.e., make and model of vehicle, brakes, ABS, hourly installation rate, etc.)[4]. Additional staff work is needed to determine the feasibility and cost effectiveness of retrofits.

6. Technical Feasibility

There are no technology limitations for this strategy.

7. Additional Considerations

Several State and Federal agencies have public outreach websites that highlight the relationship between tire pressure and saving money (e.g., U.S. DOT – It All Adds Up, CEC – Fuel Efficient Tire Program, California's Energy Efficiency Program – Flex Your Power, IWMB – National Tire Safety Week). Enforcement of this type of strategy will be extremely difficult.

Affected Entities: California's vehicle repair facilities and refueling stations and vehicle owners.

Government Agencies to coordinate with: U.S. DOT, CEC, IWMB, and others as outreach information becomes available.

8. Division: Stationary Source Division
Staff Lead: Theresa Anderson
Wayne Sobieralski
Section Manager: Mike Miguel
Branch Chief: Mike Tollstrup

9. References:

[1] *U.S. Department of Transportation, NPRM on Tire Pressure Monitoring System FMVSS No. 138, 09/2004*

[2] *California Inspection and Maintenance Review Committee, Review of the Smog Check Program, 11/2006*

[3] *Based on Air Resources Board's California Emissions Forecasting System, Population and Vehicle Trends Report, Statewide Daily Vehicle Fuel Consumption (Gasoline), EMFAC 2002, Version 2.2*

[4] *Based on retail quotes obtained by the Air Resources Board, 07/2007*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B11*
ID NUMBER:	*EJAC- 11/ARB 2-22*
TITLE:	*REQUIRE LOW GWP REFRIGERANTS FOR NEW MACS*[1]
PROPONENT:	*2006 CAT REPORT AND ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4th quarter of 2010.

This strategy is also not a stand-alone measure. It is anticipated to be integrated into larger new measures focused on new vehicle GHG emission standards (e.g., *Pavley II* described as Summary # B33, page B-110 later in this appendix).

The central premise of the proposed strategy is the replacement of high global warming potential (GWP) refrigerants used in California's mobile air conditioning systems (MACS) with lower GWP alternatives that also represent better lifecycle climate performance (LCCP) than the current refrigerant. MACS in today's motor vehicles use nearly universally the refrigerant HFC-134a with a GWP of 1,300. A two-fold approach will be explored under the proposed new regulation. First, the core of the strategy would focus on developing new regulations requiring that new MACS use refrigerants with a lower GWP (e.g., 150 or less) in new vehicles currently not subject to the existing vehicle GHG emission standards (AB 1493). For vehicles subject to AB 1493, this strategy would explore further MACS improvements after the regulation is fully phased in 2016. Second, staff will explore the potential climate benefits from a universal phase out of HFC-134a (or other high GWP refrigerants) used in other remaining vehicle classes in the California fleet such as heavy-duty on- and off-road vehicles including new as well as in-use systems. Again, the identification of suitable alternatives would be based on lifecycle climate performance.

Alternative refrigerant development has been a highly contested arena in recent times. Driven primarily by Europe's landmark directive to phase out the use of HFC-134a in the MACSs of new vehicle types starting in 2011, several low GWP refrigerants are currently

[1] New alternative low GWP refrigerants in MACS are desired to the extent that these alternatives have lifecycle climate performance (LCCP) that exceeds the performance of the current refrigerant HFC-134a. Thus, new low GWP refrigerants are sought in systems that leak less and are more efficient than current systems.

under investigation and evaluation for toxicity, safety, energy efficiency, and technical feasibility by multiple industry entities. Identification of an eligible replacement for the European car market, the largest in the world, would boost efforts in California and could accelerate the implementation of new regulations mitigating the impact of refrigerants in MACS.

3. Early Action Description

This strategy explores the phase out of HFC-134a in all MACS in new vehicles certified for sale in California (heavy- and light-duty, on- and off-road) with the intent to reduce direct and indirect emission impacts and promote only the use of alternative refrigerants with superior lifecycle climate performance. Opportunities in the in-use fleet will also be evaluated.

Regulation of refrigerants is happening globally. The European Union (EU) is taking the lead. In 2006, the European Parliament and the Council decided that the dates for the phase-out of refrigerant HFC-134a in the European community shall be set at January 1, 2011 for new types of vehicles and January 1, 2017 for all new vehicles[1]. The US EPA's I-MAC Program[2] has generated significant debate and progress regarding alternative refrigerants and the options for the US car MACS market with the best lifecycle climate performance. Extensive cooperation between government agencies, NGOs, and industry is needed to accomplish this strategy and fully realize its benefits.

4. Potential Emission Reductions

The proposed strategy was included in the Climate Action Team report of March 2006 and it emerged from ARB's regulatory work for the motor vehicle greenhouse gas emissions regulation (AB1493). That work suggests that potential GHG emission reductions for a universal phase out of HFC-134a in new and in-used MACS in California are on the order of 2.5 MMTCO2E by 2020. However, the uncertainty with the estimate is on the order of 50%.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Preliminary cost estimates were developed for the revisions to the Climate Action Team Report of March 2006 that ARB and other agencies are undertaking. The numbers generated for that report are first-order estimates based on simple assumptions gleaned from the published literature about alternative MACS. Only estimated capital costs were considered. Additional staff analysis is needed to determine operating costs, cost savings, and economic impacts. The air conditioning system life is expected to be the same as current systems. Capital costs for the introduction of new refrigerants in the California fleet were estimated to be on the order of $150 million by in 2020 based on assumptions that changes begin to phase in around 2013. This estimate is based on an incremental cost per vehicle of €20 to €25 per LDV in 2003[3] and is also applied to the other vehicle categories. For the HFC-152a alternative refrigerant, it is not expected that maintenance costs will change significantly or that there would be cost implications when converting an existing HFC-134a system design to use HFC-152a since development is fairly advanced. Selection of some other alternative refrigerants, for example CO_2, could be significantly costlier. Incremental energy consumption estimates are not presented here. The reference below cites a potential 10% reduction in energy consumption for the

HFC-152a alternative for LDVs, but this will almost certainly vary significantly with vehicle category, engine type, operating cycle, extent of optimization achieved during system redesign, etc. Also, energy consumption for some other alternative refrigerant selections, for example CO_2-refrigerant systems, can actually show an increase under some operating conditions. Significant additional analysis is needed to enable and improve cost and performance estimates of the various alternative technologies.

6. Technical Feasibility

New HFC refrigerants with GWP values less than 150, such as those currently under development for the US market by Honeywell and DuPont, and existing alternative refrigerants such as HFC-152a (with GWP approximately 120[4]) or R744 (CO_2, GWP=1), are possible substitutes for HFC-134a in new vehicles. The feasibility of these low GWP refrigerants is being investigated and evaluated extensively by multiple entities. As suggested by the European directive, all indications are that a feasible refrigerant alternative to HFC-134a is eminent.

7. Additional Considerations

The EU regulation timeline calls for the phase out of HFC-134a beginning with new vehicles types in 2011. Thus, auto makers serving that market face at present time a critical go, no-go decision point regarding refrigerant selection for their systems.

The outcome of the AB1493 legal challenges, including the pending California waiver request to the US EPA, will impact significantly the form and function of the measure as proposed.

Each alternative new refrigerant will be evaluated from a lifecycle emissions standpoint to ensure that the net impact on greenhouse gas emissions is properly characterized and in order to promote improvements not only on refrigerant containment to minimize leakage, but also in system performance to reduce the parasitic impact of the MACS on the vehicle engine.

Affected Entities: Vehicle owners and operators, vehicle manufacturers, mobile air conditioning system repair facilities, mobile air conditioning system and component manufacturers, and air conditioning refrigerant manufacturers.

Government Agencies to coordinate with: U.S. EPA and the European Commission.

8. Division: Research Division
Staff Lead: Pablo Cicero
Section Manager: Tao Huai
Branch Chief: Alberto Ayala

9. References:

[1] *Schulte-Braucks, R., "Implementation of the R134a Phase Out," 2006 Mobile Air Conditioning Summit, Saalfelden, Austria, Feb. 17, 2006.*

[2] *The I-MAC Program is a consortium of government, industry, academia, and other stakeholders led by the US EPA with the objective to develop superior and improved HFC-134a mobile air conditioning technology with 50% lower leakage and 30% greater efficiency than current production-ready systems.*

[3] *Alternative Refrigerants Assessment Workshop, Presentation at the SAE 2003 Alternative Refrigerant Systems Symposium, Phoenix, Arizona, July 14, 2003*

[4] *The GWP limit is intended to be that of HFC-152a, for which the IPCC 3rd Assessment Report suggested a 100-year forcing of 120. The more recent IPCC/TEAP Special Report on HFCs and PFCs suggests a direct forcing of 122.*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B12*
ID NUMBER:	*EJAC-12/ARB 2-23*
TITLE:	*ADDITION OF AC LEAK TEST AND REPAIR REQUIREMENTS TO SMOG CHECK*
PROPONENT:	*2006 CAT REPORT AND ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 1st quarter of 2011.

The strategy proposes to explore the addition of a new motor vehicle air conditioning system (MVACS) leak test and repair requirements to the existing California Smog Check program for HFC-based MVACSs. To the extent that a cost-benefit analysis supports this measure, implementation will require the 1) identification, selection and verification of one or more reliable and low cost HFC refrigerant leak detectors to be used in the Smog Check station setting; 2) development of a new Refrigerant Leak Check I/M procedure and protocol; 3) new and additional training of the Smog Check technicians including achieving appropriate technician A/C repair certification; and 4) working with the Bureau of Automotive Repair (BAR) of the Department of Consumer Affairs (DCA) for mandating the new procedure to be integrated into the statewide Smog Check program. Research will be needed to evaluate the feasibility of the new test and extensive discussions among multiple stakeholders, including first and foremost BAR and legislature staff are anticipated. For this reasons, this strategies cannot be developed before 2010 to meet the definition of a discrete early action.

3. Early Action Description

The proposed strategy will explore the addition of a refrigerant leak check to the “pass” criteria for the California vehicular inspection and maintenance (I/M) program, Smog Check, for all vehicles that undergo the test. As a result, all vehicles that pass Smog Check would have MACS that are either nearly leak-free or empty and excluded from further use of the AC system unless the leak is repaired. Vehicles that are determined to have unacceptable leak rates would be required to be repaired as a condition for registration. A similar requirement is already in place and enforced by some local air quality management districts. Thus, the proposed early action seeks to expand these local requirements statewide.

4. Potential Emission Reductions

The proposed strategy was included in the Climate Action Team report of March 2006 and it emerged from ARB's regulatory work for the motor vehicle greenhouse gas emissions regulation (AB1493). That work suggests that potential GHG emission reductions for a leak test and repair program in California are on the order of 0.45 MMTCO2E by 2020. However, the uncertainty with the estimate is on the order of 50%.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Some preliminary, but incomplete cost information exists. In 2005, BAR licensed approximately 9,700 Smog Check stations and almost 14,000 Smog Check technicians. Approximately 9.2 million Smog Check inspections were conducted at these Smog Check stations in 2005[1]. Each Smog Check station would have additional one-time estimated expenditures of about \$200~\$300 for each hand-held HFC leak detector. Technician training for AC service certification would cost up to \$280 per person. Based on above information, the total cost for equipment and training in California would be approximately \$6M; \$2M for equipment and \$4M for training. In addition, the leak test would add time to the current Smog Check test, impacting the shop and the customer. Finally, in the case where a MVACS is found to require repairs, the customer would incur additional and potentially significant costs. Technology is also rapidly evolving and improving. Today's MVACS are much tighter than older system and the industry, in response in part to regulatory interest, is proactively seeking refrigerant leak improvements in the system sold to car makers. These factors and many other economic impacts have not been thoroughly researched and additional time is needed to complete a full cost-benefit analysis of the proposed measure.

6. Technical Feasibility

There are several commercially available hand-held HFC leak detectors or "sniffers" on the market. These detectors are currently in use by the AC service and repair industry. The detectors would need to be demonstrated capable of reliable and accurate determination of refrigerant leaks in the Smog Check station setting at rates as determined in the proposed strategy. All MVACSs leak refrigerant naturally as the systems are not hermetic and deterioration is expected. A pass criterion based on a reasonable threshold leak rate requiring professional AC servicing or system disabling needs to be defined rigorously, perhaps as a fraction of the original system charge or other appropriate metric. The current commercially available sniffers can detect a concentration of refrigerant in a sample volume of some currently unknown combination of leakage and ambient air. Further investigation is needed to define the pass criterion for either a threshold concentration or leak rate.

Currently, the service industry standard established by the Society of Automotive Engineers, SAE J1628 Standard[2], requires charging the AC with sufficient refrigerant prior to conducting a leak check. This procedure might be not suitable for the implementation of this strategy because the leak check would be conducted at Smog Check Stations, which normally do not have AC charging equipment. A new leak check protocol would be necessary. The measure must also require professional AC servicing or system disabling when leakage is found. Other methods, such as injection of dye gases, are under investigation.

7. Additional Considerations

ARB and BAR would need to work closely as both agencies share responsibility for Smog Check. Roles and responsibilities for both agencies in the context of the proposed strategy should further analysis suggest to proceed to full development and implementation will need to be defined.

Affected Entities: The I/M program operators at the Smog Check stations, the owners of all vehicles required to undergo I/M, shops that repair vehicular AC systems, BAR, and DCA, The I/M operators would have to become certified for AC maintenance, purchase new instruments for detection of HFC emissions, and adopt the new protocols for including the new test into the Smog Check procedure. BAR and DCA would be expected to develop a new I/M procedure and protocol to accommodate the new HFC leak check. The agencies would be impacted with additional enforcement requirements for the proposed strategy.

8. Division: Research Division
Staff Lead: Tao Zhan
Section Manager: Tao Huai
Branch Chief: Alberto Ayala

9. References:

[1] *California Inspection and Maintenance Review Committee, Review of the Smog Check Program, September 29, 2006. http://www.imreview.ca.gov/reports/final_report.pdf*

[2] *SAE J1628, Technician Procedure for Using Electronic Refrigerant Leak Detectors for Service of Mobile Air-Conditioning Systems, November 1998.*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B13*
ID NUMBER:	*EA B-1, B-2*
TITLE:	*WAFFLEMAT SYSTEMS*
PROPONENT:	*STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009.

3. Early Action Description

The WAFFLEMAT System (registered trademark) is a set of interconnected WAFFLEBOXES equally spaced within the area of a new foundation. Concrete is then poured over the WAFFLEBOXES to create a concrete slab, thereby decreasing the volume of concrete used on new foundations and indirectly reducing the amount of CO_2 emitted from the production and transportation of Portland cement. The WAFFLEMAT System is advertised by the manufacturer to reduce CO_2 emissions by 20% when used for new residential home concrete slab foundations built on "marginal" soils (e.g., expansive soil, rocky soil, and/or hydro-collapsible soil), where an increase in slab thickness is required. The 20% CO_2 emission reduction was calculated by comparing the WAFFLEMAT System to a 10 inch uniform thickness slab. The actual percentages of CO_2 emission reductions will vary depending on the type and thickness of the slab which the WAFFLEMATs are compared against.

4. Potential Emission Reductions

Based on information from the manufacturer, ARB staff estimated that utilization of the WAFFLEMAT System on new residential home construction may reduce 3.5 metric tons (MT) of CO_2 emissions per slab for a 2,000 square foot home. If one assumes that 200,000 new residential homes are built each year in California, 25% of those homes are located on marginal soils and all 25% of those homes utilize the WAFFLEMAT System, there may be an annual CO_2 emission reduction of 0.18 million MT. Using 2008 as the baseline year, by 2010 there will be a cumulative 0.35 million MT CO_2 emission reduction and by 2020 there will be a 2.1 million MT CO_2 emission reduction. The primary purpose of the WAFFLEMAT System is to displace the total amount of concrete needed in a residential foundation and still meet or exceed construction requirements. In theory, if less concrete is needed, less needs to be produced. Emission reductions of oxides of nitrogen (NO_x), particulate matter (PM), hydrocarbons, and carbon monoxide

(CO) will also be achieved with the use of the WAFFLEMAT System if it is assumed that overall less concrete will have to be used.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The WAFFLEMAT System is estimated to cost $1.20 per square foot of foundation. When compared to the cost of concrete for a 10 inch uniform thickness slab foundation on a 2,000 square foot footprint, the WAFFLEMAT System and its reduced volume of concrete may increase the price of a foundation by $1,200. This equates to an approximate cost effectiveness of $340 per MTCO2E. Additionally, the WAFFLEMAT System is advertised to provide cost savings in labor and ground preparation. ARB staff does not have information to quantify labor and ground preparation cost savings at this time.

The use of the WAFFLEMAT System is limited to use with marginal soils that generally require thicker slab foundations. Use of the WAFFLEMAT System with good soils may result in an increased use of concrete.

6. Technical Feasibility

The WAFFLEMAT System was developed in 1995 and has had over 6.5 million square feet of concrete poured on it without one structural callback or failure. Pacific Housing Systems, Inc. (the distributor) and two engineering firms conducted studies to determine the design compliance and capability of the WAFFLEMAT System. Their results showed that the WAFFLEMAT System is technically feasible and has advantages over the traditional slab foundation in areas with marginal soils. Those advantages include, but are not limited to: the slab's ability to withstand larger cantilevers, reductions in labor costs, provides a more definite value for concrete costs, and reductions in overall installation time.

7. Additional Considerations

- The use of the WAFFLEMAT System does not ensure reduction in the production of cement. CO_2 emission reductions are achieved with the use of the WAFFLEMAT System if cement plant operators reduce the production of Portland cement.
- Currently, not every new single-family residence home is built on marginal soils. We are not certain what percentage of new homes is built on marginal soils versus good soils. This could impact the CO_2 emission reduction estimates.
- Geotechnical engineers should be employed to recommend which foundation is suited for a site's soil type.
- ARB will need to work with other state and local agencies to ensure that the use of the WAFFLEMAT System meets building codes.
- ARB staff needs to work closely with legal to determine scope of authority for requiring the use of WAFFLEMAT Systems on new construction.

8. Division: Stationary Source Division
Staff Lead: Alicia Violet
Section Manager: Todd Wong
Branch Chief: Michael Tollstrup

9. References:

Altshuler, Sam. "Lowering the Carbon Footprint When Using the Wafflemat System for Concrete Slab Foundations." Suncoast Post-tension - Pacific Housing System, Inc.. February 2007.

Charlton, Aurora. "Structural Engineering Case Study Report: Wafflemat Slab On Grade Post Tensioned Foundation System." Front Range Engineering, LLC. August 2006.

Cook, John. "Wafflemat System Design Considerations." Pacific Housing Systems, Inc. and MKM and Associates. April 2006.

Richards, Tom. "A Sales/Marketing Comparison and Positioning Statement of the WAFFLEMAT System to Post-Tensioned Slabs." Pacific Housing Systems, Inc.. March 2006.

Richards, Tom. Telephone Interview and email. July 16 and 24, 2007.

State of California – Business, Transportation, and Housing Agency; Department of Housing and Community Development. "California's Deepening Housing Crisis." June 2007.

Treanor, Rich. "Wafflemat Frequently Asked Questions." Pacific Housing Systems, Inc.. March 2006.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B14*
ID NUMBER:	*EJAC-15/ARB A-15*
TITLE:	*GREEN SHIP INCENTIVE PROGRAM*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

This measure is focused on reducing emissions of diesel particulate matter (PM) and nitrogen oxides (NOx) by phasing in the installation of emission control devices on new or existing vessels. While reductions in NOx and the elemental carbon portion of PM may reduce global warming, other aspects of this measure may contribute to it. For example, some of the emission control devices that can be used to significantly reduce PM and NOx will have fuel penalties associated with them, resulting in higher carbon dioxide (CO_2) emissions. Other control strategies may reduce fuel consumption and CO_2 emissions. However, the overall effect of this measure on GHG emissions is expected to be minimal.

We do intend to analyze the potential to modify this measure to also address GHG emissions. However, for several reasons, this analysis cannot be conducted in a short timeframe due to the complexity of the technical and jurisdictional issues. For example, more advanced ship hull and propeller designs have been proposed as a way to reduce fuel consumption and CO_2 emissions in some studies. However, it is uncertain whether we can influence design changes on vessels built outside the United States. In addition, it is expected that ship operators would already incorporate such changes to reduce their operating expenses unless there are extremely high capital cost impacts or other barriers. Furthermore, to fully address GHG emissions, a review of all the various emissions from ships and their impact on global warming would need to be conducted. The relevant emissions would include CO_2, methane, black carbon PM, sulfur oxides, refrigerants, and NOx. Some of these emissions contribute to global warming, while others have the opposite effect. In addition, some emissions effects may be localized whereas others are not. Finally, the potential control strategies for each type of emissions would need to be determined.

3. Early Action Description

This measure is included in the ARB’s Emission Reduction Plan for Ports and Goods Movement. The measure, as currently proposed, seeks to reduce emissions of PM and

NOx by phasing in the use of cleaner ships at California ports. There are two levels of clean ships: "30/30 vessels" that are 30 percent lower in NOx and PM than current vessels meeting International Maritime Organization (IMO) standards, and "60/90 ships" that are 60 percent lower in PM and 90 percent lower in NOx than IMO compliant vessels. By 2020, the goal is to have clean ships make 90 percent of all California port visits, with 30/30 vessels making 40 percent of ship visits, and 60/90 vessels making 50 percent of ship visits. The ship operator would be expected to choose the specific emission control devices. Examples of potential emission controls include selective catalytic reduction, more advanced fuel injectors, fuel/water emulsions, onboard water scrubbers, and cylinder lubricant control systems. This measure seeks to encourage or direct ship operators to either retrofit existing vessels or incorporate emission control devices into new build vessels. The measure could be and incentive program, a voluntary agreement, a regulation, or use some other mechanism.

Although this measure is currently designed to focus on PM and NOx emissions, it could be modified to also control GHG emissions. As a first step, the impact of the existing NOx and PM controls on GHG emissions should be evaluated. Next, additional opportunities to address GHG emissions would need to be investigated. Existing studies suggest a number of potential control measures that would reduce fuel consumption and therefore CO_2 emissions (as well as other pollutants). These measures include the incorporation of optimized hull and propeller designs in new ship builds, operational changes focused on fuel efficiency, new methods of hull maintenance to reduce fouling, and the use of wind, solar power, and fuel cells.

4. Potential Emission Reductions

As mentioned above, this measure is not currently designed to reduce GHG emissions, and the potential impact on GHG emissions has not been quantified. Staff believes that the impact will range from a slight increase to a slight reduction in GHG emissions.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

TBD

6. Technical Feasibility

Improved engine design in new marine engine can improve combustion characteristics and reduce CO_2 emissions. However the impact of control measures to reduce PM, NOx, and SOx may increase CO_2 emissions.

7. Additional Considerations

See discussion under **"Staff Recommendation."**

8. Division:	Stationary Source Division
Staff Lead:	Paul Milkey
Section Manager:	Peggy Taricco
Branch Chief:	Daniel Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B15*
ID NUMBER:	*EJAC-16/ARB A-19*
TITLE:	*ANTI-IDLING REQUIREMENT FOR CARGO HANDLING EQUIPMENT AT PORTS*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

Staff believes significant informational gaps or constraints exist due to the dynamics of mobile cargo handling equipment operations, union labor contracts, and safety and security concerns, which prevent the implementation of an anti-idling requirement within the timeframe required for early action measures. The very nature of these operations makes it extremely difficult to determine what constitutes unnecessary idling. To illustrate, cargo handling equipment is often required to move rapidly from one location to another; and some equipment, such as rubber-tired gantry (RTG) cranes, have operator cabs approximately 50 feet above the ground, making it unsafe for the operator to exit the cab (i.e., idling limitations prevent air conditioner operation). It is inherently problematic and may complicate the development of idling restrictions at port terminals because they are generally larger than 200 acres and at any given time may have hundreds of pieces of equipment operating. All of these issues need further evaluation and many concerns need to be addressed.

In order to pursue this strategy, it would be necessary to collect complete equipment and facility specific operational data by facility type and/or operation. This data must be analyzed to identify similarities/dissimilarities in idling (equipment specific) at each facility and determine whether certain idling durations can be minimized and still not inhibit the functionality or efficiency of their operation. The next step would be to take this information and determine the extent to which cargo handling equipment engines idle, and what fraction of this total could be considered as unnecessary idling. Data logging would be the recommended method of collecting the various operational data needs. However, the variability in facility operations and the fact that the data must be equipment specific, taking into account the duty cycle of the engine, makes this a significant challenge, albeit achievable. While many data gaps prevent us from determining what is considered unnecessary idling at existing port or intermodal rail yard operations at this time, upcoming emission control retrofit demonstration programs for port equipment (such as top picks, side picks, RTG cranes, and reach stackers) include data logging components that will provide some data to help us evaluate this issue.

These efforts will be undertaken over the next two years and will help inform the decision on the appropriateness of pursuing an anti-idling measure.

3. Action Description

This early action strategy proposes to adopt a statewide regulation to limit or prohibit unnecessary idling of mobile cargo handling equipment that operates at California ports or intermodal rail yards. The limiting or prohibiting of unnecessary idling will result in reduced fuel usage, fuel cost savings, and environmental/health benefits. A reduction in fuel consumption should result in greenhouse gas emission reductions, as well as, reductions of criteria or toxic air contaminants. However, the magnitude of these reductions is unquantifiable at this time due to lack of operational data. In the event it is determined feasible to establish restrictions on idling, the proposed strategy could be considered as amendments to the existing regulation for cargo handling equipment at ports and intermodal rail yards.

4. Potential Emission Reductions

The potential greenhouse gas emission reduction potential of idling restrictions on cargo handling equipment cannot be quantified with any certainty at this time, but is anticipated to be low given the limited number of cargo handling equipment statewide.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Information is not available to estimate costs or economic impacts of this proposed Early Actions Strategy. However, the sectors that may incur costs from a restriction on idling include engine manufacturers, distributors, dealers, facility owners or operators, shipping lines, industries that contract with the ports or intermodal rail yards for movement of goods, and ultimately the end-user of the applicable consumer products.

6. Technical Feasibility

Limiting or prohibiting engine idling of mobile cargo handling equipment is likely to be technically feasible. However, the environmental benefits, cost effectiveness, emission reduction potential, and potential economic impacts on their operations can only be determined once more research and data collection has been completed and that data substantiates the extent to which unnecessary idling occurs. (See discussion under **"Staff Recommendation."**)

7. Additional Considerations

See discussion under **"Staff Recommendation."**

8. **Division:** Stationary Source Division
Staff Lead: Lisa Williams
Section Manager: Cherie Rainforth
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B16*
ID NUMBER:	*EJAC-26/ARB A-17*
TITLE:	*ELECTRIFICATION OF AIRPORT GROUND SUPPORT EQUIPMENT*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering this recommendation.

Those categories of ground support equipment (GSE) most amenable to being electric powered already have a high percentage of zero emission vehicles (ZEV). There may be some other categories of GSE that could be candidates for either ZEV technology or hybrid electric vehicle technology. Assessing feasibility for the early action timeframe can be addressed over the next year. The potential greenhouse gas emission reductions from this discrete strategy appear to be negligibly small because the number of affected vehicles is small.

3. Action Description

This Early Action Strategy proposes to accelerate the replacement of airport GSE by specifying electrification. The proponents of this measure did not provide any details on the dates for the accelerated electrification, the categories of GSE units specifically targeted, or the percentage of electrification required.

This measure would overlap with the implementation of two recently-adopted ARB regulations for off-road equipment that include GSE - large spark ignited (LSI) engines and in-use diesel equipment. The LSI regulation, that became effective May 12, 2007, incorporates requirements of the recently-terminated Memorandum of Understanding (MOU) with the airline industry that calls for 30% electrification of the airline-owned GSE fleet in the South Coast Air Basin by 2010. The LSI regulation applies to gasoline and liquid natural gas-powered GSE. On July 27, 2007, ARB adopted an in-use diesel off-road equipment regulation that requires diesel equipment fleet owners to reduce their fleet-average emissions of NOx and PM in future years by turnover of a specified percentage of their fleet horsepower. Until staff sorts through how this measure would mesh with these regulations, it is unclear how or if there would be conflicts between the measure and the regulations.

In addition to these two ARB regulations, the South Coast Air Quality Management District (District) has proposed a statewide measure for emission reductions from GSE in the South Coast Air Basin by requiring accelerated zero emission vehicle penetration and more stringent fleet-average emission standards for GSE. The District's proposed measure would require airlines in the South Coast to increase the percentage of ZEVs in their GSE fleets from 30% to 45% by 2014, an increase of 15% additional ZEV penetration.

4. Potential Emission Reductions

If the measure were to achieve an additional 15% electrification of the GSE fleet by 2014 as suggested by the SCAQMD, this measure would represent about 1,200 additional electric GSE units. The most likely categories of GSE that might be amenable for electrification include push back tractors and cargo loaders for which we have estimated energy requirements, fuel use, and electricity use for replacement ZEV units. Assuming that each diesel unit on average uses 2,800 gallons of diesel fuel per year (about 3.5 gallons per hour), this represents an emission reduction of 0.036 million metric tons per year of CO2 emissions. Providing electricity from the California utility grid to recharge batteries for replacement ZEV units would require approximately 67 million kWh per year and would emit approximately 0.027 million metric tons of CO2 annually, assuming each kilowatt-hour would require on average about 400 grams of CO2 (Source: CEC). Thus, the net expected CO2 emission benefit from this proposed measure would be on the order of 0.007 MMTCO2E per year.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

If we assume that the Early Action Strategy would require an additional 15 % ZEV vehicles in the GSE fleets, the airlines could incur significant costs, since the requirement would mandate the early replacement of nearly 1,200 units by 2014. Assuming average unit costs for ZEV GSE equal to $60,000, the total cost of the measure would be on the order of $70 million. For units that reach the end of their lifetime during this period, there would be no lost revenue from early replacement, but for units that have to be retired early, there would be a revenue impact on airlines.

6. Technical Feasibility

Airlines have already undertaken substantial electrification of certain categories of the GSE fleet including baggage tractors and belt loaders representing an estimated 46% of the total statewide GSE fleet, mostly in the South Coast Air Basin and at Sacramento International Airport. Other categories of GSE that might be targets for electrification are pushback tractors and cargo loaders and cargo tractors, representing about 41% of the 200 GSE fleet. Pushback tractors represent almost 70% of the potential CO2 emissions, while cargo loading and tractor equipment represents about 30% of potential CO2 emissions. Electric pushback tractors are currently deployed in limited quantities in airline GSE fleets, while electric battery powered cargo loading equipment and cargo tractors have not yet been successfully demonstrated.

7. Additional Considerations

None.

8. Division:	Planning and Technical Support Division
Staff Lead:	Jim Lerner
Section Manager:	Gary Honcoop
Branch Chief:	Kurt Karperos

9. References:

New Emission Standards, Fleet Requirements, and Test Procedures for Forklifts and Other Industrial Equipment, ARB's LSI Regulation, effective May 12, 2007

Regulation for In-use Off-Road Diesel Vehicles, approved by ARB July 27, 2007

Final Air Quality Management Plan, approved by SCAQMD June, 2007, Off-Road Measure 04

California Electricity Consumption by County in 2005, CEC.

Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004, Final Staff Report, December 22, 2006, CEC.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B17*
ID NUMBER:	*EJAC-18*
TITLE:	*ELECTRIFICATION OF CONSTRUCTION EQUIPMENT AT URBAN SITES*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

The ARB recently adopted an off-road diesel rule at its July 2007 Board hearing. This regulatory measure is believed to address the recommendations of the Environmental Justice Advisory Committee regarding the electrification of construction equipment at urban sites. That is because the measure requires or allows for the use of lower emission technologies including electrified equipment.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B18*
ID NUMBER:	EJAC-19
TITLE:	*HYBRIDIZATION OF MEDIUM- AND HEAVY-DUTY VEHICLES*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 1ST quarter of 2011.

ARB staff was asked to investigate the feasibility of "hybrid electric technology for medium- and heavy-duty trucks" as an early action item to address greenhouse gas (GHG) emission reductions mandated by Assembly Bill 32. Medium duty trucks are trucks with gross vehicle weight rating (GVWR) between 8,501 and 14,000 pounds and heavy-duty trucks are 14,001 pounds and greater. Staff's evaluation focuses on trucks with GVWR greater than 10,000 pounds, which hereinafter are referred to as heavy-duty trucks.

Despite the wide spread presence of hybrid electric technology in the passenger car industry, heavy-duty hybrid technology for commercial trucks are still in the pre-production development stage. The major factors hindering a rapid introduction of cost-effective hybrid technology in the heavy-duty vehicle sector are the high incremental cost and risk aversion by both hybrid builders and buyers.

Many of the present prototype heavy-duty hybrid vehicles use off-the-shelf components that are not designed and optimized for on-road heavy-duty hybrid vehicles. Some hybrid components are not commercially available and must be custom designed for the application. These components significantly increase the cost of the hybrid system due to the low production volumes. Also, reliability and maintainability of hybrid trucks are still being tested and long term durability of hybrid trucks has not been demonstrated for most applications.

Staff anticipates that hybrid technology will become available in the next 5 or more years as a commercial product for applications on urban delivery, utility, and other specialty work trucks with a potential to provide significant greenhouse gas emission reductions by 2020.

3. Early Action Description

Adopt a regulation and/or incentive program to take advantage of emerging hybrid electric technology for heavy-duty trucks.

Hybrid electric technology offers the potential to significantly improve fuel efficiency and performance while reducing emissions. However, these benefits are highly dependent on the duty cycle of the truck application. Hybrid technology provides the greatest benefit when used in vocational applications that have significant urban, stop-and-go driving, idling, and power take-off operations in their duty cycle. Such applications include parcel delivery trucks and vans, utility trucks, garbage trucks, transit buses, and other vocational work trucks. Line haul trucks are typically operated for long periods of time at high speed and load cruise driving modes and therefore, hybrid technology may not be as beneficial for this type of truck.

Several governmental and non-governmental organizations have been sponsoring research and developing programs that will bring together hybrid developers, truck and engine manufacturers, and truck users in an effort to speed up the introduction of heavy-duty hybrid technology into the marketplace.

Among the governmental organizations, the United States Department of Energy (DOE) has initiated a cost shared research and development program for advanced heavy-duty hybrid propulsion systems that will focus on improving fuel efficiency of heavy duty trucks and buses. DOE is funding approximately $4 million per fiscal year of cost shared projects with the heavy-duty hybrid industry (50/50 cost share) on this program[1].

The United States Department of Transportation (DOT) in partnership with the North American Bus Industries, invested over $50 million, in a program that demonstrated fuel efficiency improvements of a transit bus through hybrid propulsion and weight reduction using composite materials. In addition to investing in other hybrid and fuel cell demonstration programs, DOT also continues to fund the purchase of advanced hybrid electric transit buses[1.]

The United States Department of Defense is also a major sponsor in the development of heavy-duty hybrid technologies for combat vehicles and trucks.

The United States Environmental Protection Agency (U.S. EPA) has sponsored a program to develop and demonstrate the benefits of a hydraulic hybrid propulsion technology which is an alternative to hybrid electric propulsion. This system captures and stores a large portion of the braking energy by pumping hydraulic fluid into a high pressure hydraulic fluid accumulator and pressurizing an inert gas. The energy stored in the high pressure fluid is then used to help propel the vehicle during the next vehicle acceleration event[2].

Among the non-governmental organizations are the WestStart-CALSTART operated Hybrid Truck Users Forum (HTUF) and the North West Hybrid Truck Consortium. HTUF assists truck users and hybrid truck makers to move to pre-production manufacturing levels and deployment and reduce overall costs by creating common fleet requirements and joint purchase commitments. Under the HTUF program, working groups that are currently active include the Parcel Delivery Working Group, the Utility Working Group, the Refuse Truck Working Group, and the Shuttle Bus Working Group[3].

The Hybrid Parcel Delivery Truck Working Group focuses on Class 4 to 6 urban parcel delivery trucks and includes members from several major parcel delivery fleets in North America such as Federal Express (FedEx), United Parcel Service (UPS), Purolator Express, and the United States Postal Service (U.S. PS). FedEx was the first truck operator to test parcel hybrid electric trucks. It put 18 hybrid electric trucks on the road in 2005, 75 more in 2006 and is currently considering 75 more. Purolator Express has 10 hybrid electric parcel trucks and plans to add 115 trucks this year. UPS also plans to acquire 50 Eaton hydraulic hybrid trucks this year[3].

The Hybrid Utility Working Group is made up of 14 fleets and focuses on Class 5 to 7 utility and specialty work trucks. The work group has deployed 24 utility trucks nationwide and preliminary results indicate fuel savings ranging between 10 to 50 percent[3].

The Hybrid Refuse Working Group consists of 7 private and municipal refuse truck fleets. The purpose of this working group is to develop a common chassis and vehicle performance specifications in an effort to speed up the introduction of hybrid trucks for refuse fleet operations. In May 2007, the group released a request for proposals to purchase and deploy 8 preproduction hybrid refuse trucks for assessment[3].

The Northwest Hybrid Truck Consortium is a coalition of several county and city governments, and utility companies located in the state of Washington. The group works together with HTUF to identify hybrid opportunities and raise regional and state funding for hybrid deployment. In 2006, the consortium acquired $250,000 in funding from the U.S. EPA's West Coast Collaborative project, to support early hybrid truck deployments by reducing the incremental cost of the purchased hybrid trucks[4].

4. Potential Emission Reductions

To understand the potential of hybrid technology in reducing GHG emissions, staff estimated GHG emission reductions in 2020. Assuming that all new Class 3 to 5 (10,001 to 19,500 lbs) trucks sold in California beginning in 2015, use hybrid technology, the GHG emission reductions from these trucks are estimated to be 0.5 MMT of CO_2e in 2020. These hybrid trucks represent 20 percent of the total California fleet in the same class and their vehicle miles traveled represents 30 percent of the total California fleet of the same class. To put this in perspective, if 100 percent of the Class 3 to 5 trucks were hybrids in 2020, the potential GHG emission reduction could be up to 1.7 MMT of CO_2e.

Table 1

	CY 2020 (MY 2015-2020)	CY 2020 (ALL MYS)	
Vehicles (10,001 to 19,500 lbs)	53,421	273,739	- Fuel economy improvement: 35% - Base truck fuel economy: 7.2 mpg
Daily Vehicle Miles Travel	3,694,200	12,166,000	
GHGs Reduced in 2020 in MMT of CO_2e	0.5	1.7	

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

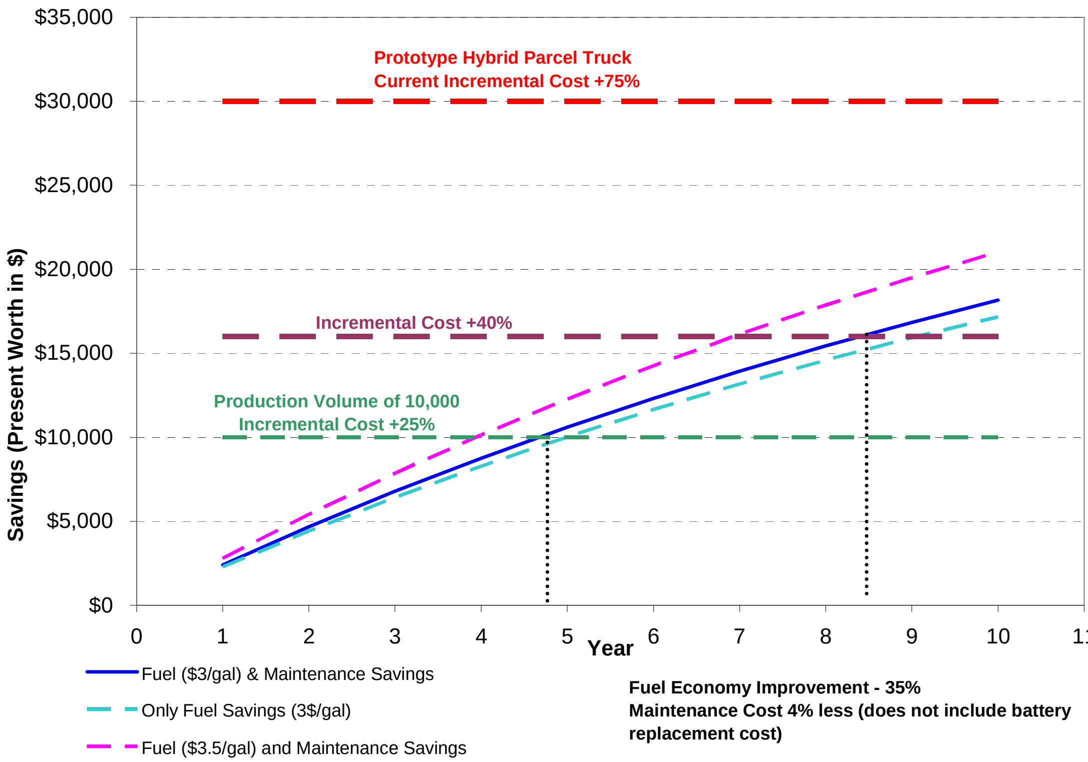
Table 2 compares a base truck with a "replacement" hybrid truck. As shown in the comments column of the table, the data were obtained from different sources. Incremental cost and in-use performance data were obtained from a hybrid truck builder and DOE published reports for hybrid buses and CNG trucks.

Table 2

	Base Diesel Truck	Parcel Hybrid Truck	Comments
Cost ($)	$40,000	$70,000	- Cost of the base truck is from a truck dealership. - Incremental cost is from a hybrid builder: $30,000 (75% above cost of base truck) for preproduction parcel trucks. ($10,000, or 25% above cost of base truck for production volume of 10,000 trucks or more)
Fuel Economy (mpg)	7	9.5	Fuel economy improvement 35% Base truck fuel economy is assumed to be 7 mpg.
Fuel Cost ($/gal)	$3.00	$3.00	In estimating fuel savings, the fuel price per gallon is assumed to remain constant during the 10 year lifetime period of the truck.
Annual VMT (miles)	22,000	22,000	Source: Parcel delivery truck feet operator
Life of the vehicle (years)	10	10	Source: Parcel delivery truck feet operator
Maintenance Cost	Unknown	Unknown	Being pre-production vehicles, the parcel fleet operator has not realized maintenance savings because of problems in software, transmission, parking brake, etc.
Assumed maintenance costs: ($/mile)	$0.16	$0.15	Base truck maintenance $0.16/mi[5] Hybrid truck maintenance cost is assumed 4% less – considers only labor and parts cost without battery replacement[6]

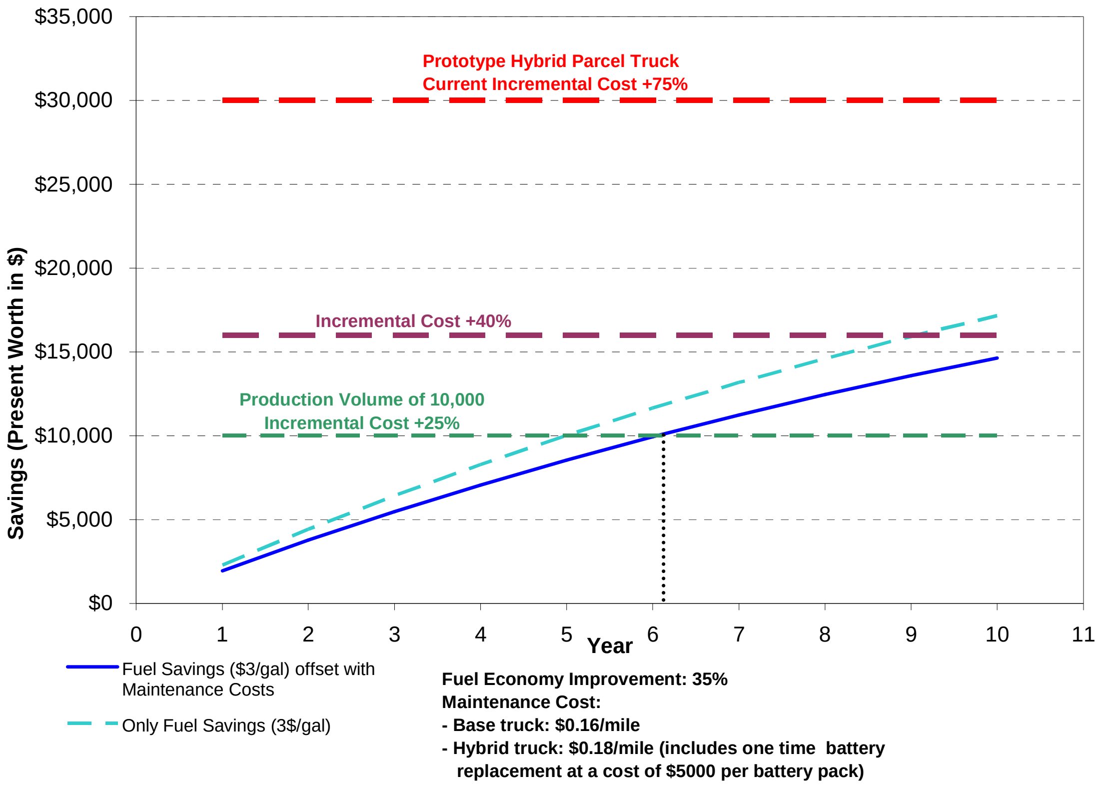
Figure 1 shows the savings realized from fuel economy improvements and reduced maintenance needs for the 10-year life of the parcel delivery truck. Future year savings were converted into 2007 dollars using a 7 percent discount rate. Assuming a 75 percent incremental cost difference, the chart shows that the preproduction hybrid parcel truck never recovers the incremental cost from fuel and maintenance savings. If production volume increases and the incremental cost drops to 25 percent of the cost of the base truck, then the hybrid truck will recover the incremental cost within 4 to 5 years. Note that in Figure 1 the maintenance cost for the hybrid truck is assumed to be 4% less than the base truck and does not include battery replacement.

Figure 1



According to one hybrid truck builder, the hybrid parcel delivery truck equipped with nickel metal hydride (NiMH) will require a one-time battery replacement during its life. The replacement battery pack costs between $5,000 to $8,000. Adding this cost to the maintenance cost of the hybrid truck results in $0.18/mile which is 10 percent higher than that of the base truck. Figure 2, below, shows the savings and payback period for this truck. It can be seen that the payback period for the high volume production hybrid truck (incremental cost of 25 percent) becomes 6 years.

Figure 2



6. Division:	Mobile Source Control Division
Staff Lead:	Daniel Hawelti
Section Manager:	Stephan Lemieux
Branch Chief:	Michael Carter

7. References:

[1] *U.S. Department of Energy. "21st Century Truck Partnership: Roadmap and Technical White Papers", Report No.: 21CTP-0003. December 2006. (http://www1.eere.energy.gov/vehiclesandfuels/pdfs/program/21ctp_roadmap_2007.pdf)*

[2] *U.S. Environmental Protection Agency. "World's First Full Hydraulic Hybrid in a Delivery Truck" EPA420-F-06-054, June 2006. (http://www.epa.gov/otaq/technology/420f06054.pdf)*

[3] *WestStart-CALSTART. "Hybrid Truck Users Forum". (website: http://www.calstart.org/programs/htuf/, accessed August 6, 2007)*

[4] *West Coast Collaborative. "Northwest Hybrid Truck Consortium" (website: http://www.westcoastdiesel.org/grants/wa-hybrid-trucks.htm, accessed: August 6, 2007)*

[5] *Chandler, K. and K. Walkowic. . "King County Metro Transit Hybrid Articulated Buses: Final Evaluation Results", U.S. DOE Technical Report: NREL/TP-540-40585. December 2006. (http://www1.eere.energy.gov/vehiclesandfuels/avta/pdfs/heavy/king_co_final_12-06.pdf)*

[6] *Chandler, K., K. Walkowic, and Nigel Clark. "United Parcel Service (UPS) CNG Truck Fleet: Final Results", August, 2002. (http://205.168.79.26/vehiclesandfuels/ngvtf/pdfs/31227.pdf)*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B19*
ID NUMBER:	*EA B-1, B-2*
TITLE:	*CEMENT (A): ENERGY EFFICIENCY OF CALIFORNIA CEMENT FACILITIES*
PROPONENT:	*STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure is recommended for addition to the list of early actions. The Board date for consideration of this item is anticipated in 4th quarter of 2010

Staff assessment indicates that significant near term carbon dioxide (CO_2) reductions might be obtained by implementing energy efficient practices and technologies at California's cement facilities.

A proposed measure to consider greater reduction from low-carbon fuels in the cement sector is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation, which could entail large cost impacts on cement production in California.

3. Early Action Description

California's eleven cement facilities manufacture between 10 to 15 percent of the United States cement production. Annually, these eleven facilities use large amounts of energy: 1440 gigawatt hours (GWh) of electricity (7.2% of total energy used), 17.6 million therms of natural gas (2.6%), 2.3 million tons of coal (87.9%), 0.25 tons of coke (<0.1%), and burns 5.9 million tires[1] (2.3%). The three sources that result in CO_2 emissions from cement facilities are: 1) direct emissions from fuel combustion, 2) direct emissions from limestone calcination, and 3) indirect emissions from electricity use. Reducing CO_2 emissions from fuel combustion, calcination, and electricity use requires facilities to convert to using a low-carbon fuel, decrease fuel consumption, and improve energy efficiency practices and technologies in cement production[2].

4. Potential Emission Reductions

In 2004, CO_2 emissions from fuel combustion, limestone calcination, and electricity use are estimated at 10.8 million metric tons of CO_2 equivalent per year ($MMTCO_2E$). Staff estimates that CO_2 emissions from fuel combustion are 4.1 $MMTCO_2E$, limestone calcination 5.9 $MMTCO_2E$, and electricity use at 0.8 $MMTCO_2E$.

Potential carbon dioxide reductions are estimated for all three of those categories listed below:

A. Fuel Combustion

Clinker production is the most energy-intensive stage in cement production, accounting for over 90% of total industry energy use[3]. The most prominent fuel source used for clinker production in California is coal. Coal accounts for over 95% of all CO_2 emissions from fuel consumption. Coal emits over 210 pounds of CO_2 per million Btu (MBtu) compared to 117 pounds of CO_2 per MBtu of natural gas[4, 5]. If a low-carbon fuel, such as natural gas, is substituted for coal, potential reductions could exceed 1 $MMTCO_2$ reduction per year can be obtained. Further evaluation and information is needed to determine the feasibility of this proposed measure. Issues such as cost, infrastructure, plant modifications, and operational requirements need to be evaluated in more detail to determine if switching to low-carbon fuels can be recommended as a strategy for reducing greenhouse gas emissions.

B. Energy-efficiency Practices and Technologies

Energy-efficiency practices and technologies in cement production can be implemented to decrease CO_2 emissions. Energy consumption in the cement plant sector consists of energy used for raw material preparation, clinker production and finish grinding[6]. Raw material preparation and finish grinding is an electricity-intensive (indirect emissions) production. However, electricity accounts for only 10% of the overall energy use at cement plants[7].

1. Raw Materials Preparation

The standard raw materials used in California for cement production are limestone, chalk, and clay. These materials are usually extracted from a quarry close to the plant. Approximately 1.5 tons of raw materials are required to produce one ton of Portland cement. Raw materials preparation involves transport systems, blending, grinding mills, and classifiers (separators). Using the most highly efficient equipment in this category can save electricity and reduce indirect CO_2 emissions by 0.2 $MMTCO_2E$ at power plants.

2. Clinker Production

The heating of cement kilns to produce clinker is the largest user of energy at these facilities. To improve the energy-efficiency in clinker production, improved control systems, improved combustion system, reduction in kiln heat loss, grate coolers, preheater/precalciner type systems, newer mill drives, and use of secondary fuels can be utilized. Staff lacks sufficient data to estimate potential CO_2 reductions from California facilities. Much of the information available is based on national averages of cement plant efficiencies. Using this data, potential energy efficiency improvements could result in up to 0.7 $MMTCO_2E$ annually. Staff believes this estimate overstates the potential CO_2 reductions because a study by Lawrence Berkeley National Lab[8] found that California plants operate more efficiently than the national average. In order to more accurately assess potential reductions, staff needs to obtain plant specific information from each California facility.

3. Finish Grinding

To produce powdered cement, clinker is ground to the consistency of face powder. Finish grinding involves process control, grinding mills, and classifiers. Carbon dioxide emissions reduction of 0.1 $MMTCO_2E$ can be accomplished with high-efficiency equipment.

5. Estimated Costs/Economic Impacts and the Impacted Sectors/Entities

The estimated cost impact to California's cement industry to use cleaner fuels and more energy-efficient equipment/technologies is about one billion dollars annually. These costs are discussed below.

Coal is the major fuel used in California to heat the kiln used in clinker production. If coal was replaced by natural gas, total annual cost increase for California facilities would be estimated at $500 million. This equates to approximately $200 per metric ton of carbon dioxide equivalent ($MTCO_2E$) reduced per year. It should be noted that this number only reflects the difference in fuel costs. Additional work is needed to determine infrastructure and other costs that may significantly change the cost effectiveness.

Several technologies and practices exist that can reduce the energy intensity of various process stages of cement production. If each cement facility changed to higher energy-efficiency equipment for raw material preparation, the total cost is estimated at $258 million. This corresponds to approximately $1,300 per $MTCO_2E$ reduced. The finish grinding process is estimated at $111 million if all cement facilities changed equipment for higher energy-efficiency. This equates to $1,100 per $MTCO_2E$ reduced. Finally, improved energy-efficiency for clinker production involves many technical stages. Total cost for modification is estimated at $90 million. This corresponds to $125 per $MTCO_2E$ reduced. Additional information is necessary to more accurately determine energy efficiency strategies.

6. Technical Feasibility

This measure is technically feasible by applying low-carbon fuels for heating cement kilns and using more efficient equipment at various process stages of cement production. However, staff lacks information regarding the actual benefits that would be achieved by replacing existing equipment with more energy efficient equipment used at each California cement facility. Administering these measures could be costly to industry.

7. Additional Considerations

- Applicability of technological changes will depend on the current and future situations regarding individual plants. Capital projects would be implemented only if the company has more than 50 years of limestone reserve remaining. Cement plants with a shorter supply would most likely implement minor upgrades and focus on energy management measures.

- Mercury emissions from coal and raw materials needs to be evaluated. An assessment needs to be implemented concurrently with greenhouse gas reduction strategies to better understand impacts to industry.

8. Division: Stationary Source

Staff Lead: Jim Stebbins
Section Manager: Todd Wong
Branch Chief: Michael Tollstrup

9. References

[1] *Coito F, Friedmann R, Powell F, Price L, and Worrell E. 2005. Case Study of the California Cement Industry. Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-59938*

[2] *Martin N, Worrell E, and Price L. 1999. Energy Efficiency and Carbon Dioxide Emissions Reduction Opportunities in the U.S. Cement Industry. Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-44182*

[3] *Ruth M, Worrell E, Price L. 2000. Evaluating Clean Development Mechanism Projects in the Cement Industry Using a Process-Step Benchmarking Approach. Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-45346*

[4] *ICF Consulting. 1999. Emissions Factors, Global Warming Potentials, Unit Conversions, Emissions, and Related Facts.*
Website: http://www.p2pays.org/ref/07/06861.pdf

[5] *Leonardo Academy, Inc. – Multiple Pollutant Emission Reduction Reporting System (MPERRS). 2007. Emission Factors and Energy Prices for Leonardo Academy's Cleaner and Greener Program.*
Website: http://www.cleanerandgreener.org/download/efactors.pdf

[6] *Worrell E and Galitsky C. 2004. Energy Efficiency Improvement Opportunities for Cement Making – An Energy Star Guide for Energy and Plant Managers. Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-54036*

[7] *Van Oss HG. 2005. Background Facts and Issues Concerning Cement and Cement Data. United States Geological Survey. Open-file Report 2005-1152*

[8] *Masanet E, Price L, de la Rue du Can S, and Brown R. 2005. Optimization of Product Life Cycles to Reduce Greenhouse Gas Emissions in California. Lawrence Berkeley National Laboratory for the California Energy Commission. CEC-500-2005-110-F.*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B20*
ID NUMBER:	*EA B-1, B-2*
TITLE:	*CEMENT (B): BLENDED CEMENTS*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for addition to the list of early actions. The Board date for consideration of this item is anticipated in 2nd quarter of 2009.

3. Early Action Description

From cement plants, carbon dioxide (CO_2) emissions are released into the atmosphere during the calcination process and the burning of fuels to produce clinker, the main ingredient in Portland Cement. The calcination process involves the decomposition of calcium carbonate (limestone) to calcium oxide (clinker or lime), in which CO_2 is released. Calcination is carried out in furnaces or kilns under very high temperatures.

A strategy to reduce CO_2 emissions involves the addition of blending materials such as limestone, fly ash, natural pozzolan and/or slag to replace some of the clinker in the production of Portland Cement. Currently, ASTM cement specifications allow for replacement of up to 5% clinker with limestone. Most manufacturers could in fact replace up to 4% with limestone. Caltrans allows for 2.5% average limestone replacement until testing of the long term performance of the concrete is complete. Caltrans currently has over $1 million in task orders and is devoting considerable staff resources to the evaluation of limestone blending in cement. Caltrans also currently has standards for using flyash and slag in concrete. Other blending practices will be explored.

Industrial wastes such as coal fly ash, blast furnace slag, and silica fume have cementitious properties and can be blended with clinker or added at the concrete mixing stage. The quality of these blended cements is comparable to Portland cement. The differences are lower initial strength, but higher final strength, and improved resistance to sulfates and seawater. In the United States, one study estimated that these blended cements account for about one percent of the domestic cement shipments. Limitations on further penetration of fly ash, slag, and silica fume into the concrete market depends on the availability, construction standards, transportation costs, and user preferences; however, the potential CO_2 emission reduction potential warrants further examination. Caltrans mandates 25% fly ash in almost all of its concrete and allows up to 35% fly ash replacement of cement. Caltrans also allows up to 60% slag replacement of cement in all concrete. Additional staff work is needed to determine other current blending practices in the State.

4. Potential Emission Reductions

In 2004, cement plants in California produced about 11.2 million metric (MM) tons of clinker, which corresponds to about 10.8 MM tons of CO_2 emitted from the production of clinker. Blending with 25% fly ash, slag, or silica fume has a potential to reduce CO_2 emissions by reducing the need to produce an equivalent amount of clinker. For each percent of cement replaced by these blending materials, CO_2 emissions may be reduced proportionally. At this time, ARB staff does not have information on how much of blended cements are used in California and further evaluations are needed to estimate the potential use of these blended cements to reduce CO_2 emissions. It should be noted that this strategy may not reduce CO_2 emissions in California, but is expected that cement imports would be reduced and thus result in reduced emissions elsewhere.

Fly ash that is typically blended is a by-product of coal combustion and may contain mercury. Mercury levels in fly ash need to be evaluated.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The production of clinker is an energy intensive process, which involves heating and maintaining high temperatures in the cement kilns and its associated equipment (pre-heaters/pre-calciners). This strategy may result in the production of less clinker per unit of cement produced. In blending with 5% limestone, it is estimated that clinker production could be reduced by 0.56 MM tons, resulting in a reduction in energy use of 2.14×10^6 MMBtu. This is equivalent to not burning 75,000 tons of coal and saving plant operators in the State about $3 million. Due to the lack of information, the economic impacts of blending 25% fly ash or slag can not be determined at this time.

6. Technical Feasibility

The replacement of Portland Cement with limestone is technically feasible and may reduce CO2 emissions per unit of cement produced. However, additional evaluations are warranted to assess the feasibility, availability, and cost of blended cements containing fly ash and slag.

7. Additional Considerations

- The cement plant industry and environmental groups support the use of blending cements.

- The production of clinker at cement plants is also a source of mercury emissions caused by naturally occurring mercury found in the raw materials and from the combustion of coal. ARB staff has begun its efforts to understand the processes involved with the production of Portland cement, gather information to assess the impacts of both CO2 and mercury emissions, evaluate control options for all pollutants, and assess the economic impacts to the industry and the public. It is not yet fully understood the potential impacts of blending on mercury emissions from cement manufacturing facilities.

- Ongoing and future discussions with Caltrans and other agencies will ensure that the addition of blended cements will meet their specifications and approval.

- Additional work is needed is needed to determine the extent to which blending currently is being done and the technical feasibility of establishing limits for the blending of fly ash and slag as a strategy to reduce CO2 emissions.

8. **Division:** Stationary Source Division
Staff Lead: Duc Tran
Section Manager: Todd Wong
Branch Chief: Michael Tollstrup

9. References

Van Oss HG. 2005. Background Facts and Issues Concerning Cement and Cement Data. United States Geological Survey. Open-file Report 2005-1152.

Website: http:www.ket.org/Trips/Coal/AGSMM/agsmmtypes.html

U.S Cement Plant Detail by State, PCA, December 31, 2004

Lisa J. Hanle, CO_2 Emission Profile of the U.S Cement Industry,
U.S. Environmental Protection Agency.
Kamala R. Jayaraman and Joshua S. Smith, ICF Consulting

PCA, Cement Kiln Dust Production Summary for California Portland Cement Plants.

Peter Hawkins, Paul Tennis, and Rachel Detwiler, The Use of Limestone in Portland Cement: A state-of-the-Art Review, PCA.

Climate Action Program at Caltrans, California Department of Transportation, December 2006.

Using Coal Ash in Highway Construction: A Guide to Benefits and Impacts
Website: http://www.epa.gov/epaoswer/osw/conserve/c2p2/pubs/greenbk508.pdf

Joe Seay, HeadWaters, Incorporated, August 2, 2007, Personal Communication.

Pam Herman Milmoe and Martin Ross, United States Environmental Protection Agency, Evaluation of the Environmental Impacts from APCA/CW Partnership, presented at the 1999 American Council for an Energy Efficient Economy (ACEEE)

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B21*
ID NUMBER:	*EJAC-22*
TITLE:	*RELATIVELY INEXPENSIVE ENERGY SAVINGS MEASURES WITH SHORT PAY BACK TIMES FOR FOSSIL FUEL POWER PLANTS BUILT PRIOR TO 1980*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid- 2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

In addition, the ARB staff recommends working with the local air districts to start a dialogue with power plant owners and operators to disseminate information on energy savings measures through an educational outreach program. For these measures, there is already inherent built-in advantages (cost savings and short payback times).

3. Early Action Description

This strategy proposes that the ARB implement relatively inexpensive energy savings measures with short payback times for fossil fuel-fired power plants constructed prior to 1980. The EJAC has identified these older electrical generating units as significant contributors to greenhouse gas emissions due to their lower thermoelectric efficiencies compared to new state-of-the-art combined-cycle power plants.

ARB staff determined that there are 59 fossil fuel-fired thermoelectric power plants within California that came online prior to 1980. In 2005, the CO_2 emissions from these facilities totaled 13.9 million metric tons of CO_2-equivalent per year (MMTCO2E) or about 25 percent of total CO_2 emissions from all power plants in California.

ARB staff has identified two potential measures that could generate energy savings with minimal investment. The U.S. Department of Energy's (DOE) Industrial Technologies Program helps industrial plants operate more efficiently and profitably by identifying ways to reduce energy use in key process systems. The program has identified that minimal improvements in burner efficiency can result in significant savings. The following case from the DOE website (www.eere.energy.gov/industry) provides an example of the potential savings:

> Case: Consider a 50,000 lb/hr process boiler with a combustion efficiency of 79% (E1). The boiler annually consumes 500,000 million Btu (MMBtu) of natural gas. At a price of $8.00/MMBtu, the annual fuel cost is $4 million. The installed cost is

$75,000 for a new burner that provides an efficiency improvement of 2% (E2). The cost savings is:

Cost Savings = Fuel Consumption x Fuel Price x (1 - E1/E2)
= 500,000 MMBtu/year x $8/MMBtu x (1 – 0.79/0.81)
= $98,760/year

The simple payback on investment is:
Simple Payback = $75,000 / $98,760/year = 0.76 year

The table below shows the annual dollar savings for 1% and 3% efficiency improvements.

Burner Combustion Efficiency Improvement	Annual Energy Savings (MMBtu/year)	Annual Dollar Savings
1%	6,250	$50,000
2%	12,345	$98,760
3%	18,290	$146,320

The second measure is the use of newly-developed “automated migration tools,” which consist of control and process optimization software to enhance operations by automatically balancing the process for optimum results, coordinating boiler/turbine control, emissions monitoring, economic dispatch, and fleet management. (Westinghouse Process Control, Inc., a subsidiary of Emerson, is one such vendor of this technology.) Some of the benefits include lower maintenance and materials costs, improvements in heat rate, and reductions in unit startup time. The software allows power plants to modernize their operations for greater efficiency and output, while at the same time minimizing their generation downtime.

These efficiency-enhancing measures may be of particular interest to the coastal power plants that have once-through cooling. Once-through cooling is an effective and relatively inexpensive method for re-condensing super-heated steam after it has been used to generate power. Once-through cooling draws sea water into the plant, where it flows through a heat exchanger to cool the steam, and then subsequently returns the heated water back into the environment. Sea water is abundant and cold and represents an efficient means of handling waste heat. However, once-through cooling may have a deleterious environmental impact due to the entrainment and impingement of marine life; therefore, the State Water Resources Control Board is currently developing a statewide policy to implement federal Clean Water Act requirements for power plants that utilize once-through cooling. If a less-efficient cooling method is required by these power plants, they could suffer an energy penalty ranging from 1.7 to 8.6 percent. ARB staff has identified 17 pre-1980 plants that may need to be retrofitted to comply with proposed once-through cooling requirements. Measures to mitigate this loss in overall efficiency may be especially pertinent.

4. Potential Emission Reductions

For the example case above for a single boiler, the potential emission reductions range from 0.12 to 0.34 $MMTCO_2E$ based on the fuel savings from the burner efficiency improvements. A plant-by-plant analysis is required to determine how many generating units in the State have not already gone through similar modifications and could benefit from this measure. In addition, ARB staff was not able to obtain information on specific efficiency rates associated with the optimization software. Further investigation is required. Therefore, ARB staff cannot yet determine the total emission reduction potential of this strategy. However, depending on annual fuel consumption rates for the 59 pre-1980 power plants and opportunities for at least one percent efficiency improvements, there is a potential for significant emission reduction.

A potential co-benefit of efficiency improvements that lower overall fuel use is a concurrent reduction in criteria pollutant emissions.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The cost of burner improvements will be site-specific. Also, ARB staff was not able to obtain information on upgrade costs associated with the optimization software, and further research is required. Therefore, the total cost of implementation cannot yet be determined due to the need to assess each generating unit on a case-by-case basis. Costs will be borne by the power plants, but the payback in efficiency and reduced fuel consumption should provide a short payback time and would not be expected to translate into increased electricity rates for consumers.

6. Technical Feasibility

In 2006, the DOE's Industrial Technologies Program completed 200 Energy Savings Assessments at U.S. industrial plants. Their website contains over 50 case studies for companies that have participated in past assessments and that are already saving energy and money. These studies describe demonstrated energy improvement projects, process improvement projects, and/or assessments at the plant level. These projects and accompanying savings can be replicated at similar plants.

With respect to optimization software, Westinghouse Process Control's website (www.emersonprocess-powerwater.com/solutions/pwr-successstories.cfm) describes experience with over 30 power generation projects across the U.S. and internationally.

7. Additional Considerations

- This measure would complement other actions taken by State agencies. In September 2005, the California Public Utilities Commission (CPUC) launched an ambitious energy efficiency and conservation campaign by authorizing energy efficiency plans and $2 billion in funding for 2006-2008 for the State's utilities.

- In addition, this item may be included under two CAT strategies to be implemented by the California Public Utilities Commission—specifically, "Investor Owned Utility Energy Efficiency Programs (including LSEs)" and "Investor-Owned Utility (IOU) Additional Energy Efficiency Programs/Demand Response."

Before taking this item to the Board, ARB staff recommends conducting further research to identify any additional low-cost energy savings opportunities for power plants and to obtain a more accurate quantification of the potential emission reductions based on a case-by-case analysis of options.

8. Division: Stationary Source Division
Staff Lead: Chris Gallenstein
Section Manager: Mike Waugh
Branch Chief: Mike Tollstrup

9. References:

California Air Resources Board, database on California power plants, based on air district permit information from 2001.

[2] California Air Resources Board, spreadsheet on greenhouse gas emissions from power plants for 2005, based on Energy Information Administration data.

[3] California Energy Commission, "Integrated Energy Policy Report," Appendix A: Aging Power Plant Study Group, publication #CEC-100-2005-1007-CMF, November 2005.

[4] California Energy Commission, "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004," Staff Final Report, publication #CEC-600-2006-013-SF, December 2006.

[5] California Energy Commission, "Status and Known Plans of Coastal Plants using OTC," April 2007.

[6] California Energy Commission, spreadsheet on pre-1980 generating unit ratings and status.

[7] California Public Utilities Commission, "PUC's Energy Leadership," January 2007: http://www.cpuc.ca.gov/static/070319_revenergystory0107.pdf

[8] Emerson Process Management's Power Success Stories, April 9, 2001: http://www.emersonprocess.com/solutions/power/success_story_1.asp

[9] U.S. Department of Energy, Industrial Technologies Program, Energy Efficiency and Renewable Energy, Steam Tip Sheet #24, DOE/GO-102006-2269, January 2006.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B22*
ID NUMBER:	*EJAC-23/EJAC-29/ EJAC-31*
TITLE:	*IDENTIFY AND IMPLEMENT ENERGY EFFICIENCY MEASURES AT REFINERS THAT INCLUDE, BUT ARE NOT LIMITED TO, CONDUCTING AN ENERGY AUDIT*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

Several of the measures that could be implemented to realize energy efficiency savings with potential greenhouse gas (GHG) benefits are listed in the section(s) below. Staff reviewed specifics of the necessary steps/processes necessary to implement such actions. This includes permitting and construction activities. Staff has concluded that all these measures could potentially provide moderate to significant GHG benefits. However, given the remaining uncertainties with identifying a viable strategy, staff does not recommend adding the suggested measures to the list of early actions. As part of its ongoing assessments, staff plans to:

a) Perform an evaluation to determine refiner's energy use and energy efficiency.

b) Develop a detailed strategy to define a plan to monitor changes in refinery energy uses and efficiency over time.

c) Define regulatory measures that could be implemented.

Each of these activities requires detailed analyses to ensure a comprehensive plan is adopted by each refinery before energy efficiency measures could be implemented.

3. Early Action Description

U.S. Department of Energy, the American Petroleum Institute, and large refinery facilities have completed a number of energy efficiency projects and demonstration studies in the last ten years. The results from these activities are the basis of the suggested measures for energy efficiency savings. The potential measures that could achieve modest to significant energy savings include: use of an energy management assessment system to continually optimize refinery processes, installation of new or expanding existing co-generating capacity, use of new (low-energy) technologies for desulfurization of fuels, incorporating low level heat streams back into refinery processes, reducing fouling and corrosion in cooling water streams, and treating and using low BTU refinery plant gas as an energy source. Some of these measures are currently under evaluation by refiners.

4. Potential Emission Reductions

Current ARB GHG combustion estimates suggest that California refineries emit 30 million metric ton equivalents of CO_2 annually. However, energy and GHG savings need to be determined for each refinery. Co-generation reduces CO_2 emissions by ~ 25% (not plant wide but just from this source of energy) compared to steam and electricity being delivered by an external utility. Savings are mainly derived by lower transmission losses, export of electricity and better heat management at the facility. The other measures when implemented could provide for marginal to moderate reductions (< 10%) reductions in energy needs for a given refinery with attendant GHG reductions.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

All the measures indicated above have moderate to significant costs associated with planning, design, permitting, construction and maintenance. Most if not all costs associated with implementation would be the responsibility of the refinery.

6. Technical Feasibility

Most of the proposed measures have been demonstrated to be feasible and cost effective by industry and government agency projects. However, refinery specific technical feasibility analyses need to be conducted to ensure that the specifics of each refinery are considered before adopting or mandating any energy efficiency measure.

7. Additional Considerations

Significant technical challenges exist to adapting findings from energy assessments of even a small refinery. Completing such assessments could take anywhere from 12-18 months before a report could be delivered. Based on the recommendation, construction, permitting, etc. may require additional time. Hence, adoption of measures to conduct such energy assessments is reasonable but not as discrete early action measures due to the time needed to conduct a complete assessment.

A study conducted by the California Energy Commission in participation with California refiners concluded that implementation would entail time frames of 3 or more years even for measures for which there was no significant technical, regulatory, enforcement, or other challenges. This conclusion is similar to staff's assessment of timelines necessary for adoption of any of the measures discussed above.

8. Division: Stationary Source
Staff Lead: Reza Lorestany
Section Manager: John Courtis
Branch Chief: Dean Simeroth

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B23*
ID NUMBER:	*EJAC-24*
TITLE:	*ACCELERATE THE REPLACEMENT OF CARGO HANDLING EQUIPMENT AT PORTS*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

Accelerating the replacement of cargo handling equipment at ports and intermodal railyards beyond that required by the Air Resources Board's (ARB) regulation for Mobile Cargo Handling Equipment at Ports and Intermodal Rail Yards (Cargo Handling Rule) could compromise the expected reductions in NO_x and diesel PM from that rule and would have negligible impacts on greenhouse gas emissions. Accelerating the implementation dates for compliance could potentially jeopardize the overall benefits that can be realized from the Cargo Handling Rule. While there may be some near-term increase in emission reductions, a large portion of the overall benefits that are scheduled to be realized would be lost since operators would not be able to purchase the cleaner Tier 4 engines that will be available in the post 2011 timeframe. For example, for some larger equipment, such as rubber tire gantry cranes (RTG) that have long useful lives (up to 20 years or more), high horsepower ratings, and are costly (upwards of over 1 million dollars), the regulation was designed to accelerate the turnover of this equipment such that, in most cases, a new RTG would be purchased when the ultra-low emission Tier 4 engines would be available. Having this equipment replaced sooner, as proposed in this early action measure, would result in the loss of the significant emissions benefits from a Tier 4 engine since the operator would have to purchase either a Tier 2 or Tier 3 engine. Since this equipment has a long useful life, the benefits of a Tier 4 engine would be foregone for up to 20 years.

Furthermore, it is expected that the Cargo Handling Rule, or the acceleration of that rule, would result in a negligible effect on global warming. Because the Cargo Handling Rule requires operators to move from uncontrolled engines to cleaner engines with NO_x and PM controls and in some cases to apply exhaust retrofits, there can be a fuel economy penalty as high as two to four percent. When more fuel is burned, more CO_2 is produced, and CO_2 is a greenhouse gas. However, the Cargo Handling Rule does result in the reduction of black carbon emissions which also contribute to global warming and this may offset the fuel penalty effects.

Accelerating the turnover would result in the loss of NO_x and diesel PM emission reductions over the life of the equipment resulting in a loss of public health protection and without achieving any measurable greenhouse gas benefits.

3. Early Action Description

The Cargo Handling Rule became effective December 6, 2006, and established performance standards based on the best available control technology (BACT) for new and in-use cargo handling equipment operating at these facilities. Compliance with the regulation will be phased in beginning in 2007 based on the age of the engine, whether or not it is a yard truck or non-yard truck equipment, and the size of the fleets. The performance standards and compliance dates in the regulation were designed to maximize the public health benefits from the rule, taking into account the useful life of the equipment, the use and cost of new equipment, the horsepower of the engines, and when cleaner new engines, in particular the 2007 on-road engines and Tier 4 off-road engines, would be available.

This Early Action Strategy proposes to accelerate the replacement of cargo handling equipment at ports and intermodal rail yards earlier that the compliance schedules required by the existing statewide regulation for Mobile Cargo Handling Equipment at Ports and Intermodal Rail Yards. The proponents of this measure did not provide any details on the dates for acceleration or the equipment targeted.

4. Potential Emission Reductions

As discussed under **"Staff Recommendation",** we do not expect any greenhouse gas emission benefits from this proposed early action measure.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The costs associated with accelerating the implementation dates in the Cargo Handling Rule could be significant. In most cases, the useful life of equipment would be decreased even more than required by the rule, resulting in increased costs to terminal operators, shippers, and consumers.

6. Technical Feasibility

It is technically feasible to require faster turnover of equipment at ports and intermodal rail yards. However, as discussed in "**Staff Recommendation**," accelerating the turnover would decrease the expected emission reductions of NO_x and diesel PM from the rule and have negligible impacts on greenhouse gas emissions.

7. Additional Considerations

8. Division: Stationary Source Division
Staff Lead: Lisa Williams
Section Manager: Cherie Rainforth
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B24*
ID NUMBER:	*EJAC-25*
TITLE:	*EVALUATE ENCLOSED DAIRY BARNS AS AN ADDITIONAL STRATEGY FOR THE CAPTURE AND COMBUSTION OF METHANE EMISSIONS AT DAIRIES*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

In addition to this measure, ARB staff will be evaluating potential measures for modified feed management, manure removal frequency, covered and treated lagoons, and digesters as potential strategies for reducing methane emissions.

This evaluation will be undertaken as part of ARB's actions for reducing methane emissions at dairies. These actions are not appropriate for consideration as early action measures because the time-frame is not sufficient to conduct the required in-depth cost-effective analyses, develop consistent emissions testing methods, and evaluate emerging technologies or technology-transfers. These activities must be conducted in advance of proposing any measures for reducing GHG emissions from dairy operations. ARB Planning and Technical Support Division (PTSD) staff is currently developing a protocol for calculating changes in GHG gas emissions resulting from the voluntary installation of a manure digester at animal agricultural facilities. The development of this voluntary protocol has been proposed as an early action measure and is discussed in a separate white paper prepared by PTSD.

3. Early Action Description

This strategy proposes that the ARB develop a regulation to require that housing and milking barns at dairies be vented to an incinerator or biofilter/bioscrubber as a means of controlling methane emissions from enteric fermentation. This strategy consists of fully enclosing barns and exhausting the air to an incinerator or a biofilter/bioscrubber.

Incinerators can achieve a 90 percent or greater reduction in methane emissions. However, incinerators emit oxides of nitrogen, carbon dioxide, toxic air pollutants and require the use of a fuel to promote the destruction of compounds such as methane.

Biofilter/bioscrubber technology can achieve approximately 80 percent control of emissions of volatile organic compounds (VOCs), ammonia, and hydrogen sulfide. ARB staff was not not able to confirm any control efficiencies for methane from biofilters/bioscrubbers. By-products of biofilters/bioscrubbers are water and carbon dioxide.

In their May 7, 2007 letter to the Chairman of the Air Resources Board, the Center on Race, Poverty & the Environment argues 1) that cow housing is where most enteric fermentation takes place, 2) biofilter systems are already in use for swine facilities and have been reported for dairies, and 3) have been proposed by industry in California. ARB staff has not been able to confirm the extent to which these statements are true. In addition, ARB staff is not aware of any information about the cost of these technologies or their ability to reduce GHG emissions at any enclosed animal facility.

4. Potential Emission Reductions

California's dairy cow population produces about 4.7 MMTCO2E of methane from enteric fermentation. Although biofilters/bioscrubbers and incinerators can reduce methane emissions, the overall net GHG emissions (that would occur after discounting the GHG emissions emitted from electricity required to operate the technologies and as a by-product of the technologies themselves) have not been determined.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

A detailed cost-effectiveness analysis of such systems needs to be performed prior to their application. In addition, the calculation of net reduction in GHGs must include the electricity used to move contaminated air from the barns to the filtration device or incinerator. The agriculture industry, particularly sectors involved in confined animal facilities, would be impacted by this proposal.

6. Technical Feasibility

These technologies could theoretically be transferred to dairies. However, the extent to which enclosed animal barns outfitted with these technologies could achieve a net reduction in GHG emissions, particularly carbon dioxide, has not been demonstrated.

7. Additional Considerations

This is an untested technology with likely high-energy requirements for airflow and high-water requirements for evaporative cooling. There may be some benefits in milk production by maintaining the proper temperatures inside the freestall barns. Manure handling in the confined spaces may be more difficult. An increased risk to animals will occur from overheating. Marketing campaigns based on “unconfined cows” might be compromised. Animal health and welfare issues may arise.

8. Division: Stationary Source Division
Staff Lead: Dan Weller
Regulatory Assistance Section
Section Manager: Kitty Howard
Branch Chief: Michael Tollstrup
Staff Attorney: George Poppic

9. References:

1. *Dairy Permitting Advisory Group, Recommendations to the San Joaquin Valley Air Pollution Control Officer Regarding Best Available Control Technology for Dairies in the San Joaquin Valley, Final Report – January 31, 2006, at 108-110 ("DPAG Report")*

2. *Letter to Dr. Robert Sawyer, Chairman of the California Air Resources Board. Dated: May 7, 2007. Received from Avinash Kar (Center on Race, Poverty, & the Environment) and Tom Frantz (Global Warming Environmental Justice Advisory Committee)*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Strategy Name and Proponent

SUMMARY #	*B25*
ID NUMBER:	*EJAC-26*
TITLE:	*COMPOSTING – ADOPT SOUTH COAST AND SAN JOAQUIN RULES STATEWIDE*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

3. Description

South Coast Air Quality Management District (SCAQMD) Rule 1133.2 and San Joaquin Valley Unified Air Pollution Control District (SJV) Rule 4565 were adopted for the purpose of controlling volatile organic compounds (VOC) and ammonia from co-composting facilities. This strategy would adopt SCAQMD and SJV rules for enclosed co-composting facilities statewide. Co-composting is the composting of a mixture of biosolids and manure with bulking agents to produce compost. Greenwaste facilities use green waste or food waste as the primary feedstock, and may add small amounts of manure or other biosolids as an amendment; chipping and grinding facilities reduce the size of greenwaste or wood waste to be used in composting, or as cover for landfills.

4. Potential Emission Reductions

This action is expected to have a low (0-0.1 million metric ton carbon equivalent) emissions reduction potential. The composting rules in SCAQMD and SJV were designed to reduce emissions of VOC and ammonia (as precursors to ozone and PM10). GHG emissions were not evaluated during the development of the district rules.

According to U.S. EPA, composting may result in emissions of methane from anaerobic decomposition, and non-biogenic emissions of carbon dioxide (CO_2) from the collection and transport of the organic materials to the composting site. U.S. EPA considers CO_2 emissions from aerobic decomposition to be "biogenic" and therefore does not include them in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Research indicates that efficient composting will not result in significant methane emissions, will have minimal CO_2 emissions from transportation and mechanical turning of compost piles, and can result in some carbon storage (sequestration) from the application of compost to soils. Methane emissions were estimated to be essentially zero and CO_2 emissions per ton of material composted was estimated to be 0.01 million ton carbon equivalent (MTCE) indirect CO_2. U.S. EPA estimated that centralized composting of organics results in net GHG storage of 0.05 MTCE/wet ton of organic inputs composted and applied to agricultural soil.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

SCAQMD evaluated the cost effectiveness of Rule 1133.2 under several scenarios. Under the most likely scenario for an existing facility, with enclosures for all phases of the operation, and biofiltration, the cost was $8,700 to $10,000 per ton of VOC and ammonia reduced, depending on the type of enclosure selected. Costs for a new facility were between $11,000 and $12,000 per ton. Although greenwaste composting facilities have the largest throughput of any composting operation, they are exempt because the control options were determined to be cost-prohibitive.

6. Technical Feasibility

It would be technically feasible to have all large composting facilities in the State comply with a statewide control measure similar to the SCAQMD or SJV rules. However, it is unclear at this time if the control measure would reduce GHG emissions.

7. Additional Considerations

While implementation of this strategy would certainly result in additional statewide VOC and ammonia benefits statewide, GHG reduction benefits are currently unclear. An analysis is needed to determine whether the controls (enclosure and biofilters) will reduce GHG emissions. Additionally, the Market Advisory Committee report on the establishment of a Cap and Trade Program reported that composting does not produce net greenhouse gas emissions. Furthermore, U.S. EPA has estimated that there is a net GHG storage of 0.05 MTCE/wet ton of organic inputs composted, once they are applied to agricultural soil. Data on GHG emissions from composting operations in the SCAQMD and SJV, as well as other areas of the State, need to be obtained and analyzed in order to determine if this strategy has the potential to result in GHG emission reductions.

With low-to-zero anthropogenic GHG emissions, regulating composting facilities for their GHG emissions alone may be cost prohibitive. The Market Advisory Committee noted that local governments have created incentives for increased composting based on the need to reduce the amount of material sent to landfills. Cities and counties were mandated to achieve a 50 percent source reduction by the year 2000, compared to a 1990 baseline. The current statewide diversion rate is 42 percent. If new regulations are imposed on these facilities, it could hinder further progress towards this goal. Composting, alternatively, may be considered a method of carbon sequestration and therefore a potential offset measure (for example, United States Department of Agriculture research indicates that compost usage can reduce fertilizer requirements by at least 20 percent thereby significantly reducing net GHG emissions), which would enhance the economic viability of composting. These issues need to be carefully considered and analyzed prior to proceeding with this strategy.

8. Division: Stationary Source Division
Staff Lead: Kate MacGregor
Section Manager: Richard Boyd
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B26*
ID NUMBER:	*EJAC-27*
TITLE:	*PHASE OUT PRE-1980 POWER PLANTS GENERATING AT LEAST 100 MW AND PROVIDE INCENTIVES TO REPLACE THEM WITH CLEAN ENERGY*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

ARB staff determined that the greenhouse gas reduction potential of this strategy appears to range from low (actually an increase in emissions) to large, depending on what assumptions are used. ARB staff recommends working with the local air districts to analyze the best options for each generating unit. This work would include determining to what extent natural phase-out is occurring and at what pace; considering how the existing power plants operate versus how the replacement plants will operate (combined-cycle generation is designed for baseload operation and using it as peaking capacity could result in higher emissions due to frequent startup and shutdowns where combustion systems and controls are not optimized); analyzing how planned transmission upgrades will affect the need for Reliability Must Run (RMR) units; and looking at whether new proposed power plant projects will replace the need for old generating units.

3. Early Action Description

This strategy proposes that the ARB develop a permitting system to phase out, by 2010, fossil fuel-burning thermoelectric power plants that generate at least 100 MW and were built prior to 1980. The EJAC argues that these represent the oldest, most inefficient units. The mechanism for this phase out would be through a scaled and planned annual reduction in CO_2 emissions between 2007 and 2010. The 2010 end-goal would be an emission standard equivalent to the 2007 cleanest combined-cycle plant operating at a heat rate of 6,500 Btu/kWh. Generating units that cannot meet the emission standard would be required to shut down. The proposed phase-out would occur according to the following increments of progress:

Year	Allowable CO_2 Emission Level
2007	equivalent to 2006 emissions
2008	at least 1/2 less than the difference between 2007 emissions and the 2010 standard
2009	at least 2/3 less than the difference between 2007 emissions and the 2010 standard
2010	equivalent to California's most efficient plants built in 2007 rated at 100 MW and 6,500 Btu/kwh

EJAC also suggests that ARB prohibit an RMR designation by the California Independent System Operator (CAISO) as a means to allow a unit that does not meet the emission levels to operate.

ARB staff assumes that the power plants in question will be replaced by modern combined-cycle power plants consisting of natural gas-fired combustion turbine generators where heat is recovered from the gas turbine exhaust gases to heat water and generate steam, which is sent through a steam turbine to produce additional electricity. Therefore, the amount of fossil fuel burned to generate electricity is less than older units with no heat recovery. For example, the typical electric generation efficiency of a combined-cycle plant is estimated from 40-58 percent, while a utility boiler is estimated from 25-40 percent.

ARB staff assumes that the power plants in question will be replaced by modern combined-cycle power plants consisting of natural gas-fired combustion turbine generators where heat is recovered from the gas turbine exhaust gases to heat water and generate steam, which is sent through a steam turbine to produce additional electricity. Therefore, the amount of fossil fuel burned to generate electricity is less than older units with no heat recovery. For example, the typical electric generation efficiency of a combined-cycle plant is estimated from 40-58 percent, while a utility boiler is estimated from 25-40 percent.

ARB staff determined there are 59 fossil fuel-fired thermoelectric power plants within California that came online prior to 1980. In 2005, the CO_2 emissions from these facilities totaled 13.9 million metric tons of CO_2-equivalent per year (MMTCO2E) or about 25 percent of total CO_2 emissions from all power plants in California. Of these, 30 power plants are also rated at 100 MW or more. The 30 plants represent three percent of the number of power plants statewide, yet contribute approximately 21 percent of the total MW plant capacity in the State. If all 30 plants are phased out by 2010, the State would need to secure about 20,000 MW of capacity. The facilities are located within the jurisdiction of the following air districts: Bay Area, South Coast, Mojave Desert, San Diego, San Luis Obispo, North Coast, and Ventura. The generating units consist of natural gas-fired utility boilers and combustion turbines, with the exception of one facility that uses jet fuel.

Of these 30 power plants, high heat rates and future longevity may soon be less of an issue due to several factors. First, ARB staff has determined that 18 plants have either replaced all or a portion of their generating units or the old generating units are retired or soon to be retired. Secondly, the State Water Resources Control Board is currently developing a statewide policy to implement federal Clean Water Act requirements for cooling water intake structures related to the mitigation of entrainment and impingement of marine life at power plants that utilize once-through cooling. ARB staff has identified 17 plants (14,479 MW) that may need to be retrofitted to comply with proposed once-through cooling requirements. These plants may be retired due to the cost to retrofit or may suffer an energy penalty ranging from 1.7 to 8.6 percent (at 67 percent load) to install wet or dry cooling.

Regarding reliance on RMR units, one of the ways to reduce the need to sign RMR contracts is to invest in transmission upgrades. Upgrades that increase the ability to import energy from neighboring states and Mexico, and increase the amount of energy that can be delivered to the major load centers in California, minimize the need to sign RMR contracts with aging facilities in these areas for local reliability purposes. Two major upgrades are scheduled to operating by 2008 and will increase the transmission networks import capability into Southern California by as much as 1,160 MW. The Miguel-Mission 230 kV line #2 will increase the import capability into San Diego by 560 MW and is expected to be operating by June of 2006. The short-term Southwest Transmission Expansion Plan upgrades will increase the import capability into the Los Angeles Basin by approximately 500 MW. There are no other major projects planned to increase the transmission capacity into California before 2009.

As a companion to the phase out of older, higher-emitting plants, this strategy proposes that incentives be provided to encourage clean energy substitutions. Identifying available incentive programs would be included as part of the evaluation for the Scoping Plan. However, there is a potential incentive in Assembly Bill 32 (AB 32) for facilities that implement voluntary reduction measures. AB 32 requires that adopted regulations ensure entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of these regulations receive appropriate credit for early voluntary reductions (Health and Safety Code Section 38562 (b)(3)). To support these reductions, ARB is required to adopt methodologies for the quantification of voluntary greenhouse gas emission reductions, and adopt regulations to verify and enforce any voluntary reductions that are authorized for use to comply with emission limits established by ARB (Health and Safety Code Section 38571).

4. Potential Emission Reductions

In 2005, the 59 pre-1980 power plants produced 13.9 million metric tons of CO_2-equivalent per year (MMTCO2E), which is equivalent to 24 percent of the CO_2 produced by power plants. Although available data were incomplete, plant numbers indicate capacity factors[1] ranging from 1.3 to 36.1 percent (average 13.2 percent). While recent data shows these plants operate infrequently, replacing them with new natural gas combined-cycle units would mean that the new plants will operate more because they are designed for baseload generation. Combined-cycle plants tend to have capacity factors around 85 percent[2]. Based on these assumptions, ARB staff estimates the potential emissions impact due to shut down of pre-1980 power plants and replacement with combined-cycle generation in 2010 ranging from a 2.4 MMTCO2E reduction (at

[1] A percentage that tells how much of a power plant's capacity is used over time. It is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

[2] Assumed CO_2 emission factor for combined-cycle generation is 1,100 lb CO_2/MWh, as proposed in SB 1368 regulations.

13.2 percent capacity factor) to a 60.4 MMTCO2E increase (at 85 percent capacity factor). Therefore, the emission reduction potential of this strategy is considered from low to large.

Depending on how well-controlled the existing plants are, there is the potential for criteria pollutant reductions from combined cycle. At the same time, depending on how the new facilities are operated, there is the potential for an overall increase in emissions due to frequent startups and shutdowns or higher capacity factors.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

ARB staff estimates that the cost to implement this strategy is simply the cost of replacing the old power plants with new combined-cycle power plants of identical capacity. As mentioned above, the potential replacement capacity is 20,000 MW. To replace this capacity with equivalent combined cycle generation is estimated to range from \$1.4 to 8.7 billion (using a levelized cost for combined cycle of 5.85 cents/kWh[3]) based on capacity factors from 13.2 to 85 percent. If there is a reduction in emissions, the cost effectiveness is \$564 per-MTCO$_2$E. The bulk of the costs will be borne by the electric utility industry. In turn, this could impact consumers in the form of increased electricity rates.

6. Technical Feasibility

The siting of large natural gas-fired combined-cycle plants in California started in 1997, coinciding with the passage of legislation in 1996 deregulating the California electric utility industry. Since then, 19 of these plants, totaling over 10,000 MW, are currently operating throughout the State. Therefore, the technology is proven and well-established.

7. Additional Considerations

Rules of the Oregon Energy Facility Siting Council set CO_2 emission standards for new energy facilities. The standards apply to baseload gas plants, non-baseload power plants, and non-generating energy facilities that emit CO_2. For baseload gas plants and non-baseload plants, the standard sets the net emissions rate at 0.675 pounds CO_2/kWh (675 pounds CO_2/MWh).

On October 30, 2006, the California Energy Commission (CEC) instituted a proceeding to establish a greenhouse gas emission performance standard to implement Senate Bill 1368 (Stats. 2000, Ch. 598). The bill directs the CEC, in consultation with the California Public Utilities Commission and the California Air Resources Board, to establish a greenhouse gas emission performance standard for all baseload[4] generation of local publicly owned electric utilities at a rate no higher than the rate of emissions for natural gas-fired combined-cycle baseload generation. The proposed standard was set at 1,100 pounds of CO_2/MWh, based on evaluating the performance of existing

[3] Represents an average of several cost estimates.
[4] ARB staff is awaiting interpretation from the CEC and California Public Utilities Commission regarding whether plants currently operating with low capacity factors (but which were originally designed and intended for baseload operation) are subject to SB 1368 regulations.

combined-cycle natural gas baseload plants throughout the west, with special attention paid to the performance of units in California.

The CEC adopted the regulations pursuant to SB 1368 on May 28, 2007. The final rulemaking package was submitted to the Office of Administrative Law on June 1, 2007. On June 29, 2007, OAL issued a decision disapproving the action. The CEC is currently working on addressing the decision and determining what changes should be made to the proposed regulations to address OAL's concerns.

8. Division:	Stationary Source Division
Staff Lead:	Chris Gallenstein
Section Manager:	Mike Waugh
Branch Chief:	Mike Tollstrup

9. References:

[1] *California Air Resources Board, database on California power plants, based on air district permit information from 2001.*

[2] *California Air Resources Board, spreadsheet on greenhouse gas emissions from power plants for 2005, based on Energy Information Administration data.*

[3] *California Energy Commission, "Comparative Cost of California Central Station Electricity Generation Technologies," Staff Report, publication #100-03-001, August 2003.*

[4] *California Energy Commission, "Initial Statement of Reasons for Adoption of Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities," Docket #06-OIR-1, February 2007.*

[5] *California Energy Commission, "Integrated Energy Policy Report," Appendix A: Aging Power Plant Study Group, publication #CEC-100-2005-1007-CMF, November 2005.*

[6] *California Energy Commission, "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004," Staff Final Report, publication #CEC-600-2006-013-SF, December 2006.*

[7] *California Energy Commission, Power Plant Licensing Cases, Status of All Projects, last updated 7/25/07: http://www.energy.ca.gov/sitingcases/all_projects.html*

[8] *California Energy Commission, "Proposed 15-Day Changes to Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities," Docket #06-OIR-1, May 2007.*

[9] *California Energy Commission, "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements," Draft Staff White Paper, publication #100-04-005D, August 13, 2004.*

[10] *California Energy Commission, "Status and Known Plans of Coastal Plants using OTC," April 2007.*

[11] *California Energy Commission, spreadsheet on pre-1980 generating unit ratings and status.*

[12] *Council of Industrial Boiler Owners, "Energy Efficiency & Industrial Boiler Efficiency: An Industry Perspective," March 2003.*

[13] Energy Information Administration Glossary: http://www.eia.doe.gov/glossaryindex.html

[14] Julie Gill, CAISO, personal communication, 7/24/07.

[15] Oregon's Power Plant Offset Program: http://www.climatetrust.org/programs_powerplant.php

[16] Siemens Power Generation, Combined Cycle Plant Ratings, January 2006: http://www.powergeneration.siemens.com/en/plantrating/index.cfm

[17] U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, "Annual Energy Outlook 2007 with Projections to 2030," February 2007.

[18] U.S. Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," Volume I, DOE/NETL-2007/1281, May 2007.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B27*
ID NUMBER:	*EJAC-28*
TITLE:	*PROHIBIT FUEL OIL BURNING IN PRE-1980 POWER PLANTS GENERATING AT LEAST 100 MW*
PROPONENT:	*ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

ARB staff determined that the greenhouse gas reduction potential of this strategy is low. All power plants in California built prior to 1980 and rated at 100 MW or more with oil-firing capability utilize fuel oil only for backup purposes. There is one small plant on Catalina Island rated at 9.3 MW that uses diesel as the primary fuel.

3. Early Action Description

This strategy proposes that the ARB develop a regulation to prohibit the burning of fuel oil at power plants that generate at least 100 MW and were built prior to 1980. ARB staff determined there are no power plants of 100 MW or more in California that were constructed before 1980 and that burn fuel oil as the primary fuel. There are, however, 11 plants greater than 100 MW that are permitted to burn fuel oil as backup. They are located within the jurisdiction of the following air districts: Imperial, San Diego, South Coast, North Coast, and Bay Area. During 2005, four of these 11 plants used fuel oil for some portion of the year. The combined diesel and residual fuel oil consumption during 2005 emitted an estimated 0.068 million metric tons of CO_2-equivalent (MMTCO2E), or only 0.12 percent of the total CO_2 emissions from all California power plants.

In addition, there are five power plants rated less than 100 MW that utilize fuel oil as the primary fuel. They are located in South Coast, Placer County, and Northern Sierra air districts. Generating units at four of the five plants have been retired; only the Pebbly Beach Generating Station on Catalina Island remains operational.

The longevity of four of the 11 power plants may be affected by proposed State Water Resources Board policy pertaining to coastal power plants that have once-through cooling. Once-through cooling draws sea water into the plant, where it flows through a heat exchanger to cool the steam, and then subsequently returns the heated water back to the source. Sea water is abundant and cold and represents an efficient means of handling plant waste heat. However, once-through cooling may have a deleterious environmental impact due to the entrainment and impingement of marine life; therefore, the State Water Resources Control Board is currently developing a statewide policy to implement federal Clean Water Act requirements for power plants that utilize once-through cooling. The policy may require retrofit with an alternative cooling system such as wet or dry cooling. These plants may be retired due to the cost to retrofit.

4. Potential Emission Reductions

To determine potential emission reductions, ARB staff looked at the difference in emissions due to use of alternative fossil fuels with a lower carbon profile using 2005 as the baseline and assuming 2010 consumption data will be similar. As stated above, diesel and fuel oil burning in 2005 produced 0.068 MMTCO2E. Replacing fuel oil with liquefied petroleum gas (LPG) would result in a 14 percent reduction (0.010 $MMTCO_2e$) in 2010. To replace with natural gas would result in a 25 percent reduction (0.017 $MMTCO_2e$). Therefore, the emission reduction potential of this strategy is considered to be low.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The primary cost associated with this strategy is expected to consist of either the cost of lost power when it is needed (i.e., during a gas curtailment) or the price and cost of an alternative fuel, such as LPG, and its associated infrastructure. It is also possible that some of the generating units (e.g., burners) may need to be retrofitted to accommodate a different fuel.

The costs to businesses and consumers for lost power requires more in-depth research and was not determined for purposes of this analysis; however, it is expected to be significant, particularly depending on the frequency, timing, and duration of these events.

With respect to the use of alternative fuels, the cost of an equivalent amount of LPG is less than the combined diesel and fuel oil consumption for 2005. However, without specific plant information, ARB staff cannot determine any additional costs associated with infrastructure and equipment retrofits at this time.

6. Technical Feasibility

Power generating boilers, combustion turbines, and reciprocating engines that operate on a variety of fossil fuels are not new technologies. Some of the generating units in question may already have dual-fuel firing capability and thus the conversion from oil burning to a lower carbon fuel is not expected to require any equipment retrofits. Other units will have to be looked at on a case-by-case basis to determine the feasibility of retrofits such as replacement of burner orifices to accommodate various fuels.

Another factor to consider with respect to feasibility is that facilities may be limited by geography in terms of fuel supply choices. For example, the Pebbly Beach Generating Station is located on Catalina Island just off the coast from Los Angeles and utilizes diesel fuel in their reciprocating engine generators. In addition, some regions have the need for dual-fuel capability due to natural gas curtailments. Adverse weather conditions, particularly in Northern California, during which commercial and industrial space heating loads are high, can result in natural gas curtailments and spur the need for dual-fuel capability to meet power requirements.

7. Additional Considerations

Some California local air districts have prohibitory rules that apply to power generating units that directly prohibit oil burning after a certain date. Other district rules may indirectly result in the phase out of oil burning through average emission standards that apply to multiple generating units. In order to maximize operation, these power plants would be motivated to switch to cleaner-burning fuels, install emission control technologies, or a combination of both.

8. Division:	Stationary Source Division
Staff Lead:	Chris Gallenstein
Section Manager:	Mike Waugh
Branch Chief:	Mike Tollstrup

9. References:

California Air Resources Board, database on California power plants, based on air district permit information from 2001.

[2] *California Air Resources Board, District Rules Database, main page last updated 3/24/05: http://www.arb.ca.gov/drdb/drdb.htm*

[3] *California Air Resources Board, spreadsheet on greenhouse gas emissions from power plants for 2005, based on Energy Information Administration data.*

[4] *California Energy Commission, "Integrated Energy Policy Report," Appendix A: Aging Power Plant Study Group, publication #CEC-100-2005-1007-CMF, November 2005.*

[5] *California Energy Commission, "Inventory of California Greenhouse Gas Emissions and Sinks 1990 to 2004," Staff Final Report, publication #CEC-600-2006-013-SF, December 2006.*

[6] *California Energy Commission, "Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements," Draft Staff White Paper, publication #100-04-005D, August 13, 2004.*

[7] *California Energy Commission, "Status and Known Plans of Coastal Plants using OTC," April 2007.*

[8] *California Energy Commission, spreadsheet on pre-1980 generating unit ratings and status.*

[9] *Energy Information Administration, Spot Prices for Crude Oil and Petroleum Products, last updated 7/25/07: http://tonto.eia.doe.gov/dnav/pet/pet_pri_spt_sl_d.htm*

[10] *Energy Information Administration, Spot Prices for Crude Oil and Petroleum Products, last updated 7/25/07: http://tonto.eia.doe.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm*

[11] *Energy Information Administration, Weekly Heating Oil and Propane Prices, last updated 4/19/07: http://tonto.eia.doe.gov/dnav/pet/pet_pri_wfr_dcus_nus_w.htm*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	B28
ID NUMBER:	*EJAC-30/ARB 1*
TITLE:	*REFINERY METHANE EMISSIONS*
PROPONENT:	*2006 CAT REPORT and STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure is recommended for evaluation in the Scoping Plan which will be developed as a draft by mid-2008 and must be considered by the Board prior to January 1, 2009. Evaluation as part of the Scoping Plan provides the most effective approach for fully considering the recommendation.

Currently, there is no reporting system that identifies the sources and quantity of methane emissions from refineries. However, the draft 2004 California GHG inventory lists California petroleum refinery emissions as 30 million metric tons of CO_2 equivalents. Using Air Resources Board (ARB) Emission Inventory Data[1] and ARB refinery speciation profiles it is estimated that refinery methane emissions are 1.4 million metric tons of CO_2 equivalents. Recent refinery studies[2] suggest that the majority of the methane emissions come from crude oil transfer operations, fugitive losses (valves and fittings), flares, cooling towers, and wastewater treatment.

Staff proposes to:

(a) Perform an evaluation to determine sources and magnitude of refinery methane emissions; and

(b) Develop a detailed strategy to define regulatory measures for monitoring and control of methane exemptions granted to refineries. This will include methane control measures for refinery processes currently controlled under non-methane volatile organic compounds emission limits, and for some sources with limited control requirements, e.g., cooling towers, wastewater treatment, and ponds.

3. Early Action Description

Methane is emitted from many refining operations. The major sources of methane emissions are vapor displacement from crude tanks from marine off-loading and refinery desalter emissions. During the refining processes, methane is separated from the crude oil through vacuum or atmospheric distillation. Methane emissions occur when gaseous streams are transported at various points in the refinery. The primary method for

[1] ARB Almanac database

[2] *Phone communication with Don Robinson, ICF Consulting, 7/20/2007. ICF Consulting is performing a methane study for the American Petroleum Institute. The study will determine the GHG emissions for refineries. This analysis will determine CO_2, methane, and N_2O for all U.S. refineries.* Email Communication: Don Robinson DRobinson@icfi.com

controlling methane emissions is the use of combustion devices, i.e., flare. If one excludes marine off-loading and refinery desalter emissions, most if not all refinery methane sources are low energy, i.e., low heating value, vapor streams[3] that cannot be economically recovered.

4. Potential Emission Reductions

The potential emission reductions from this measure are unknown.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

There is no accurate estimate of the costs or the economic impacts. It is expected that the costs, depending on the source, could range from low to high. For new or exempt sources the costs may be high. In contrast, existing non-methane hydrocarbon control systems already control methane emissions by default. The major impact on existing control systems would be to require that methane be included in emission capture or destruction efficiencies.

6. Technical Feasibility

Monitoring and implementation of methane emission control measures is technically feasible. However, many California refineries do not use Best Available Control Technology (BACT) for known methane sources. Use of methane BACT may require additional work for design, local planning approval, and installation. Technology that meets refinery methane BACT has been installed in some California refineries. Use of a catalytic combustion device at the Shell Martinez marine loading terminal is a good example of a methane BACT installation. Mandatory use of BACT for all crude transfer operations and refinery desalter emissions will control most methane emissions by default.

7. Additional Considerations

None

8. Division: Stationary Source Division
Staff Lead: Tim Dunn
Section Manager: John Courtis
Branch Chief: Dean Simeroth

[3] Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, *Profile of the Petroleum Refining Industry of California* (March 2004). The report was supported by the California Energy Commission through the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY#	*B29*
ID NUMBER:	*EJAC 2/CAPCOA-6/ARB 2-3*
TITLE:	*SPECIFICATIONS FOR COMMERCIAL REFRIGERATION*
PROPONENT:	*2006 CAT REPORT, ENVIRONMENTAL JUSTICE ADVISORY COMMITTEE, AND CALIFORNIA AIR POLLUTION CONTROL OFFICERS ASSOCIATION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4th quarter of 2010.

This timing will allow staff the time necessary to complete inventory research[1], interagency coordination, economic analyses, staff reports, stakeholder workshops, and public hearings to support the necessary regulation(s).

3. Early Action Description

This early action strategy was extracted from the updated Climate Action Team (CAT) work plan entitled "Reducing Direct and Indirect Greenhouse Gas (GHG) Emissions from Stationary Refrigeration and Air Conditioning (RAC) Sources[2]".

The strategy involves regulatory measures to require supermarket leak tightness and advanced design requirements for new systems as well as energy efficiency measures for new and existing systems. Direct and indirect emissions need to be considered together over the lifetime of the RAC equipment, so that choices made to reduce direct emissions (e.g., low-GWP refrigerants or standalone systems) do not adversely impact energy consumption and vice versa.

Based on current technologies, commercially available solutions for leak reduction in retail food systems (which contain more piping, fittings, and valves than other types of systems), can support establishing a 5 percent maximum annual leak rate for new

[1] Inventory work in this area is expected to be complete by late 2008.
[2] Direct GHG emissions refer to the high global warming potential (GWP) emissions of CFCs, HCFCs, and HFCs used as working fluids in RAC systems. Indirect GHG emissions refer to CO2 emissions associated with electricity required to operate the RAC equipment.

systems in 2011 and 2 percent for new systems by 2016[3]. Currently it is estimated that the average leak rate for new systems is approximately 15 percent minimum. The 5 percent maximum annual leak rate by 2011 is based on industry estimates for controlling leaks in centralized direct expansion (DX) systems, which are the predominant systems currently being installed in retail food stores[4]. To reach the proposed 2020 limit of 2 percent for the maximum annual leak rate, it is expected that indirect supermarket refrigeration systems will have to be adopted rather than low-leak or low-charge DX designs or distributed systems.

Additionally, based on commercially available technologies, the following energy efficiency improvements to reduce energy consumption in existing and new retail food stores are proposed: 10 percent reduction in energy usage from the current baseline in 2011 and 30 percent in 2016[5]. These measures will be pursued in coordination with the California Energy Commission (CEC).

The technologies required for leak reduction in retail food systems include the following: sensitive leak detection equipment, fixed leak detection methods, utilizing brazed (welded) joints instead of flanged or threaded (mechanical) joints, compressor vibration reduction, and improved or reduced numbers of Schrader valves. Additionally, owners and operators of retail food systems would be required to adopt general policies to have full accessibility to all refrigerant pipe work.

Technologies involved in advanced-design retail food refrigeration systems include reduced charge DX systems, distributed systems, secondary loop (indirect) systems, and CO_2 systems (indirect, cascade, and trans-critical systems). Advanced retail food refrigeration designs serve to reduce refrigerant charge (which is important in case of ruptures) as well as reducing leaks through shorter lines that employ fewer fittings.

The improvement of energy efficiency of retail food systems includes the following technologies: evaporative condensers, high efficiency compressor designs, floating head pressure controls, heat recovery, ambient or mechanical sub-cooling, variable speed fans/motors, improved heat exchangers, hot gas defrost, adding doors or night curtains to display cases, energy-efficient reach-ins, anti-sweat heater controls, indirect or energy-efficient case lighting.

4. Potential Emission Reductions

Estimated emission reductions of **4.7 MMTCO$_2$E** in 2020 are possible based on a growth rate of 2 percent for new retail food systems in California (from the updated CAT Work Plan); this number only includes reduced leak rate designs for new systems and energy efficiency improvements for new and existing supermarket systems. If closed cases or night curtains are required, further CO_2 reductions are possible.

[3] This strategy, which could be applied to all RAC systems over a given capacity, basically applies to retail food systems since other “large” systems currently have much lower leak rates than retail food systems, which have baseline leak rates of 15%.

[4] Industry estimates of improvements and target dates were obtained from European studies, and were presented by The Alliance for Responsible Atmospheric Policy (ARAP) in a meeting with ARB on 10/10/06.

[5] Adding doors or night covers to display cases is not included in the energy reduction estimate, and is expected to result in even greater energy benefits if utilized.

The US EPA has indicated that statewide reductions of approximately 6.8 $MMTCO_2E$ in 2020 are possible for various RAC strategies ranging from leak reduction and refrigerant recovery to indirect retail food ammonia systems[6]. Their estimate includes measures, such as mandatory leak repair for existing systems, which ARB is considering separately. Furthermore, the estimate of 4.7 MMTCO2E is a lower bound, as other measures such as mandatory reporting/repair/refrigerant deposit and return, are expected to increase the turnover rate of old systems and lead to further GHG reductions.

5. Estimated Costs/Economic Impacts and the Impacted Sectors/Entities

The estimated cost of the strategies discussed in this evaluation are expected to be on the order of \$10-\$20/$MTCO_2E$ in 2020. Estimates by the US EPA range from a savings of \$3/TCO_2E (for enhanced leak repair and refrigerant recovery) to costs of \$10/$MTCO_2E$ (for installation of an ammonia-based indirect supermarket system). Costs in the updated CAT report were estimated to be \$14/MTCO2E, based on incremental cost differences of 20% between indirect systems and traditional DX systems.

Cost-effectiveness will improve as contractors gain comfort with installation of indirect systems and energy saving devices, and as prices for such devices/system components drop with increased production.

6. Technical Feasibility

Leak reduction technologies were obtained from industry estimates of possible leak tightness improvements. Performance of advanced systems designs has been documented in US EPA, California Energy Commission (CEC), and Oak Ridge National Lab (ORNL) reports.

Information on energy saving technologies were obtained from US Department of Energy (DOE), American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), and US EPA reports, and from presentations given by Charles Zimmerman (Wal-Mart), and Denis Clodic (ARMINES) at ARB's International Symposium On Near-Term Solutions for Climate Change Mitigation in California on March 6, 2007.

All leak reduction and energy efficiency improvement technologies appear to be proven commercially-available technologies; ARAP presented leak reduction technology to ARB based on European experiences with retail food systems, and Wal-Mart has employed advanced design refrigeration systems (secondary loop with heat reclaim) as well as other energy saving measures (LED lighting, closed cases, motion detection for lighting, machine room improvements) with aggressive energy efficiency goals of 25-30 percent reductions in 4 years.

[6] Obtained from subtracting out motor vehicle A/C reductions and distributing the national reductions to California using the 2005 population fraction of approximately 12.2%.

7. Additional Considerations

Given the necessary inventory research, technical complexity and stakeholder input process, staff believes this item could be developed into a regulatory proposal to be considered by the Board by the fourth quarter of 2010.

The affected entities will be owners and operators of retail food (or similar built-up) refrigeration systems, as well as contractors/technicians who install/repair such systems and manufacturers of system components.

A partial list of trade associations possibly impacted, either positively or negatively, by the regulation follows: ARAP (described previously), the Air-Conditioning and Refrigeration Institute (ARI), ASHRAE, North American Technician Excellence (NATE), California Grocers Associations.

Coordination with the US EPA and CEC with respect to developing the regulation is ongoing.

8. Division:	Research Division
Staff Lead:	Whitney Leeman
Section Manager:	Michael Robert
Branch Chief:	Richard Corey

9. References

Alliance for Responsible Atmospheric Policy (ARAP)/CARB workshop, 10/06.

Arthur D. Little, Inc., Global Comparative Analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire Protection Applications, Final Report to the Alliance for Responsible Atmospheric Policy, March 21, 2002.

Arthur D. Little, Inc., Energy Savings Potential for Commercial Refrigeration Equipment Final Report, prepared for Building Equipment Division Office of Building Technologies U.S. Department of Energy, June, 1996.

ASHRAE Transactions: 2002 Transactions, Vol. 108, Pt. 1, AC-02-7-2 - Performance and Energy Impact of Installing Glass Doors on an Open Vertical Deli/Dairy Display Case.

ASHRAE Transactions: 2005 Transactions, The 2005 Winter Meeting, Orlando, Vol. 111, Pt. 1, OR-05-16-1 - Humidity Effects on Supermarket Refrigerated Case Energy Performance: A Database Review.

California EPA, Climate Action Team Report to Governor Schwarzenegger and the Legislature, 4/3/06.

David Godwin (USEPA), Marian Martin Van Pelt and Katrin Peterson (ICF Consulting), Modeling Emissions of High Global Warming Potential Gases from Ozone Depleting Substance Substitutes, 2003.

ICF Consulting, Emission Reduction Opportunities for Non-CO_2 Greenhouse Gases in California, Consultant Report prepared for CEC PIER Program, CEC-500-2005-121, July 2005.

IPCC/TEAP, IPCC Special Report on Safeguarding the Ozone Layer and the Global Climate System, Issues related to Hydrofluorocarbons and Perfluorocarbons, 2005.

Solvay Fluor, Advances in Supermarket Refrigeration Leak Reduction, Product Bulletin No. C/07.05/23/E

Southern California Edison, Foster-Miller, Inc. Investigation of Secondary Loop Supermarket Refrigeration Systems, Consultant Report prepared for CEC PIER Program, 500-04-013, March 2004.

USEPA, U.S. High GWP Emissions 1990-2010: Inventories, Projections and Opportunities for Reductions, EPA 000-F-97-000, June 2001.

US Census Bureau, 2002 Economic Census Manufacturing Industry Series, Air-Conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Manufacturing: 2002, EC02-31I-333415 (RV), December 2004.

Van D. Baxter, Advances In Supermarket Refrigeration Systems, Oak Ridge National Laboratory, Oak Ridge, TN 37831-6070

Van D. Baxter, Oak Ridge National Laboratory, IEA Annex 26: Advanced Supermarket Refrigeration/Heat Recovery Systems, Final Report Volume 1 – Executive Summary, April 2003.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B30*
ID NUMBER:	*SCAQMD-1*
TITLE:	*ACCELERATE INTRODUCTION AND DEPLOYMENT OF LIGHT-DUTY VEHICLE (PASSENGER) HYBRID TECHNOLOGY*
PROPONENT:	*SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

Hybrid technology is an element anticipated to be embedded in additional regulatory measures aimed at further reducing greenhouse gas emissions from new motor vehicles. Thus, this measure is recommended to be considered as part of the analysis for the strategy to strengthen light-duty vehicle standards (B33).

During ARB development of the GHG regulation in response to AB 1493, staff carefully considered the strong benefits of hybrids in reducing CO_2 emissions. One of the hurdles identified to accelerating the introduction of light-duty vehicle hybrid-technology is that hybrid electric powertrains, which include an electric motor, battery pack, power controller and other components are relatively expensive. Accordingly, staff needed to consider the degree of hybridization appropriate and cost effective for the 2009-2016 timeframe. Staff concluded implementation of full hybrid electric vehicles would be premature prior to 2016 but believed that much could be done to prepare the vehicle fleet for incorporation of full hybrids in the meantime.

Accordingly, staff included integrated starter/generator (ISG) components in nearly half of the vehicle technology package combinations that were modeled and subsequently utilized to set the adopted GHG emission standards. This provides the incentive and foundation for vehicle manufacturers to include ISG components into high volume applications, thereby driving down costs of these hybrid systems. Staff concluded that once ISG components were integrated across most of the vehicle fleet, it would be further cost-effective to increase the capability and size of these components to permit cost-effective full hybrids to be developed for deployment in the post 2016 timeframe, i.e., ones that could operate on all electric power and provide plug-in capability, assuming battery development in the meantime progresses favorably to reduce their size and cost and to improve performance and durability.

Staff also identified another hurdle - lead time for incorporating major powertrain changes throughout vehicle manufacturers' product lines. Generally powertrain changes require fairly long lead times due to the need to first develop the new components, integrate them seamlessly into the powertrain, and then test and refine them for optimum performance, reliability and durability. In addition, new machinery for producing such powertrains requires considerable planning, lead time and investment. As a result, staff provided long lead times to enable major powertrain upgrades such as incorporating hybrid systems into vehicles when manufacturers would be doing major revisions anyway as part of their normal vehicle powertrain life cycle process. This was done to avoid the excessive costs that accompany premature tear up of existing powertrains before their cycle life has expired.

3. Early Action Description

Modify the existing light-duty motor vehicle GHG emissions standards to require greater reductions, thereby forcing vehicle manufacturers to accelerate the introduction and deployment of hybrid technology.

4. Potential Emission Reductions

The currently adopted standards call for about a 30 percent reduction by 2016. Assuming that the new standards would call for about a 50 percent reduction, phased-in beginning in 2017, this measure would achieve about a 4 MMT reduction in 2020. The reduction achieved by this measure would significantly increase in subsequent years as clean new vehicles replace older vehicles in the fleet – staff estimates a 2030 reduction of about 27 MMT.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Since the technology is at an early stage of development, it is premature to estimate costs and economic impacts.

6. Technical Feasibility

While this measure is technically feasible, for the reasons stated above staff does not believe it would be cost-effective prior to 2017.

7. Additional Considerations

Hybrid technology needs further development and cost reduction if it is to be accepted by large numbers of consumers.

8. Division: Mobile Source Control Division
Staff Lead: TBD
Section Manager: Tony Andreoni
Branch Chief: Analisa Bevan

9. References:

Initial Statement of Reasons for Proposed Rulemaking, Public Hearing to Consider Adoption of Regulations to Control Greenhouse Gas Emissions from Motor Vehicles.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B31*
ID NUMBER:	*SCAQMD-2*
TITLE:	*NATURAL GAS REQUIREMENT OF 1360 WOBBE INDEX*
PROPONENT:	*SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

Staff is aware that there are several outstanding issues related to establishing a statewide Wobbe Index standard and the relationship of Wobbe Index and GHG emissions. Thus, staff recommends that ARB continue to coordinate with the SCAQMD to further evaluate the appropriateness of a statewide natural gas Wobbe Index specification.

3. Early Action Description

Establishing a statewide natural gas specification of 1360 Wobbe Index would ensure that California's historical average Wobbe Index level would be maintained. California imports about 85 percent of its natural gas supplies via the interstate pipeline; this gas historically meets a 1360 Wobbe Index. However, sources of high Wobbe Index gas, which includes California gas production and potential imported gas derived from liquefied natural gas (LNG), could significantly increase the Wobbe Index of natural gas in Southern California.

Preliminary information indicates that, in general, natural gas inherently meeting a Wobbe Index of 1360 at production has a lower GHG emissions potential than natural gas inherently meeting a Wobbe Index greater that 1360. This is also true for natural gas that has been processed for natural gas liquids (NGLs) extraction to reduce the level of a high Wobbe Index gas to a lower level. In these cases, the methane content (higher hydrogen to carbon ratio) is greater in natural gas natural gas meeting a lower Wobbe Index than natural gas meeting a higher Wobbe Index. However, reducing the Wobbe Index of natural gas by inerts injection (e.g. nitrogen), would likely result in no or minimal GHG benefits since the dilution effect does not change the GHG potential on an energy (BTU) basis.

Recent action by the California State Lands Commission on the North Baja Pipeline Expansion project recognized the significance of introducing high Wobbe Index gas into California. Although the Commission approved the project, the Commission conditioned the approval by requiring the project proponent to monitor the Wobbe Index level of the gas being brought into California from the project and to mitigate possible NOx increases that could result from the use of that gas.

By establishing a natural gas specification of 1360 Wobbe Index, all gas would have to meet this standard, therefore maintaining the historical average Wobbe Index level. However, depending on the strategies used to meet this specification, GHG emission reductions may or may not be significant.

This strategy would be regulatory and affect the natural gas production and supply sectors.

4. Potential Emission Reductions

The GHG emissions benefit of this strategy is associated with the potential to avoid GHG emissions that may result from increasing the natural gas Wobbe Index above historical average levels. As discussed, the GHG emissions benefit associated with this strategy is highly dependent on the strategies used to meet a 1360 Wobbe Index specification. If natural gas liquids extraction is applied to natural gas to reduce the level of Wobbe Index to meet proposed specification, then there is a likely GHG benefit of about 1.5 percent going from a Wobbe Index of 1385 to 1360. If inerts injection were used, there would be zero to minimal GHG emissions benefit.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The cost of this strategy has not been specifically evaluated. However, rough estimates may be applicable from prior evaluations of natural gas treatment options which include NGLs extraction and inerts (e.g. nitrogen) injection. NGLs extraction can range as low as $0.04 per million BTU of gas processed and ranges from $0.24 to $0.42 per million BTU of gas processed when considering added storage and distribution infrastructure. Also, when considering inerts injection, this option ranges from $0.05 to $0.10 per million BTU of gas processed.

The natural gas industry and rate payers would be affected.

6. Technical Feasibility

Establishing a natural gas specification of 1360 Wobbe Index is technically feasible. Technology to treat natural gas to reduce the Wobbe Index is well proven but the degree of treatment is economically driven depending on the source of natural gas production and the market where the natural gas is to be sold.

7. Additional Considerations

The California Public Utilities Commission (CPUC) previously held rulemaking to establish a natural gas pipeline specification for Wobbe Index. After considering comments including a recommendation to establish a Wobbe Index of 1360, the CPUC approved a natural gas specification of 1385 Wobbe to ensure adequate supplies of natural gas. The CPUC at that time did not consider the impact of GHG emissions in their decision.

As mentioned, the jurisdiction of establishing a statewide natural gas pipeline specification for Wobbe Index needs to be clarified. Obviously, the CPUC has historical authority to regulate natural gas quality. However, under AB32, the authority to regulate natural from a GHG perspective suggests that other agencies such as ARB now have some aspects of regulatory authority.

Currently, proposed SCAQMD -2 is not a Climate Action Team strategy.

Proposed SCAQMD-2 would be a regulatory item. Given the regulatory and technical issues that need to be addressed, development of this strategy would exceed 18 months. Further complications in developing this strategy are tied to efforts to address natural gas interchangeability. There are ongoing interchangeability test programs being sponsored by the California Energy Commission that are evaluating the effects of natural gas variability on the performance, durability, and emissions of stationary and mobile combustion equipment. Limited data indicates that certain combustion equipment can be adversely impacted as the Wobbe Index of natural gas increases resulting in increased criteria pollutants. These test programs will provide the technical basis for establishing a statewide natural gas interchangeability specification. These programs are scheduled to be completed within the next 12 to 18 months.

8. Division: Stationary Source Division
Staff Lead: Jim Guthrie
Section Manager: Gary Yee
Branch Chief: Dean Simeroth

9. References:

- *CPUC Order to Institute Rulemaking R.04-01-025*
- *CEC Public Interest Energy Research (PIER) program on natural gas interchangeability*
- *Decision of the California State Lands Commission on the North Baja Pipeline Expansion Project, July 13, 2007.*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B32*
ID NUMBER:	*SCAQMD-3/ARB 2-9*
TITLE:	*LIGHT COLORED PAVING, COOL ROOFS, AND SHADE TREES*
PROPONENT:	*SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this measure remain as an early action item. The Board date for consideration of this item is anticipated in 3rd quarter of 2008.

A non-regulatory strategy (guidance) for further action by businesses, developers, and/or individuals to reduce GHG emissions remains an early action as approved by the Board at its June 2007 hearing. In coordination with the California Energy Commission and the Lawrence Berkeley National Lab (LBNL), staff will develop research and real-world experience-based guidelines on actions that could be taken, documenting options, costs, and benefits. We would draw from local, national, and international experience. The guidelines would be neither a complete nor a necessarily suitable recommendation for every community, but rather a foundation or menu of options applicable to a broad range of communities. The development of the guidance may reveal the need for supplemental tools (e.g., calculators, sector targeted guidelines). Guidelines will be developed in close collaboration with business, community, and environmental stakeholders to ensure that the approach is as effective as possible.

3. Early Action Description

We recommend a non-regulatory voluntary program with a set of guidelines to be adopted to foster the establishment or transition to cool communities in California. The affected economic sector is the construction industry. Many of the technologies are already well established. Below is a brief description of the strategies expected to be addressed in the guidelines.

<u>Cool Roofs</u>
Cool roof programs as part of the Building Energy Efficiency standards (Title 24) which can save as much as 15 percent of cooling energy use during hot months of the year. Such a program has already been proposed (Hebert, 2005). Confined to a residential cool community program, the per-house cost premium is estimated at about $500 (Professor Akbari).

<u>Cool Pavements</u>
Pomerantz (1999) suggests that for the urban area of Los Angeles (10,000 km^2 and 1,250 km^2 paved), a change to cool pavements can result in reduction of ambient

temperature by 0.6℃ (1℉). This reduction is esti mated to result in ozone avoidance benefits of $75 million ($228 million extrapolated to California) and energy conservation benefits of $15 million per year. In 1990, California had 410,000 km^2 in total area with 28 urbanized areas with a total of 15,624 km^2 (5,091 km^2 in Los Angeles). By 1999, the urban area of the state may have reached 30,689 km^2 and the total paved area may have been 3,836 km^2 (3800 km^2 available for cool pavement retrofit).

It is estimated that a cool pavements program would require a premium price of $0.5 per square yard as there are additional costs associated with painting the surfaces**.** Manville and Shoup (2005) identified the fraction of paved area devoted to parking as 24% for the Los Angeles business district, leaving 76% of paved area for the cool pavement program; this is to keep separate the cool pavement and the parking shade program.

Shade Trees and Urban Forest

The Tree Benefit Estimator reports that a mature tree system would save about 700 kWh of energy (1,100 kg of CO_2 per household) (http://www.appanet.org/treeben/calculate.asp). Mature trees can cost as much as $300 per tree or $1200 for 4 trees surrounding a residence.

Taha et al. (2000) reported ("Three Cities,") an ambient temperature reduction of 1.2K to 1.6K for a heavily vegetated scenario; Scott et al. (1999) reported increased parking lot shade reductions of 5℃ to 7℃ (2,592 m^2 shaded area covered by 23 mature trees) while the City of Sacramento guidelines recommend 22 trees providing 776 m^2 of shade. Manville and Shoup (2005) identified 24 percent of the paved area of Los Angeles central business district (LACBD) devoted to parking. Following that same logic and using Scott et al. nearly 8 million mature trees would be needed to offer complete shade to every parking lot in California. For Sacramento, 486 mW peak power (and 92,000 $MTCO_2$ emissions) may be avoided (Taha et al.).

4. Potential Emission Reductions

As the proposed strategy consists of voluntary guidance, estimating the emission reductions is a function of the actual strategies employed as well as the magnitude of adoption. As such, potential emission reduction estimates are to be determined as part of the development of the guidelines.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Developing effective guidelines will also increase energy independence, reduce peak energy that is quite often highly polluting, have air pollution benefits through reductions in precursors to ozone and particulate matter, and offer impetus to gentrification and increases in real estate values (Thériault et al. (2005)). Application of the guidance would likely increase construction costs in California. Rise of a new California-specific construction sector would however be a significant boon to our economy. Small businesses have the flexibility of becoming a part of this new expertise construction sector. Environmental justice communities would benefit from gentrification and increases in real estate value. Significant funding from point sources, local and state governments, and the public sector could be expected.

6. Technical Feasibility

Cool roofs are already a part of Title 24, and urban forestry has long been recognized a key to energy conservation and urban gentrification, thus, these technologies are feasible and proven.

7. Additional Considerations

Affected Entities: Construction permit jurisdictions, state and local governments, construction industry

Trade Associations: Construction industry associations

Government Agencies to coordinate with: California Energy Commission & LBNL

8. Division: Research Division
Staff Lead: Ash Lashgari
Section Manager: Eileen McCauley
Branch Chief: TBD

9. References

Akbari, Hashem, Professor at Lawrence Berkeley National Lab, Personal Communication, July 30, 2007

Appendix A (~1990), "California Urbanized Areas, Raw Data," http://www.sprawlcity.org/studyCA/CAappendices.pdf

City of Sacramento's parking lot shading design and maintenance guidelines http://www.cityofsacramento.org/parksandrecreation/ppdd/pdf/SHADING_GUIDELINES_06-05-03.pdf

Hebert, Elaine (2005), "Cool Roofs in California's Title 24 2005 Building Energy Efficiency Code," California Energy Commission, Presentation http://www.buildingmedia.com/calbo/sg/PlanReview.pdf.

Langford, S & Williams, K (2007), "The State of Housing, HCD Director Lynn Jacobs Outlines California's Housing Shortage — and How to Fix It — In 2007," California Builder, Official Publication of California Building Industry Association, April. http://www.californiabuildermagazine.com/internal.asp?pid=325&spid=

Manville, M. & D. Shoup (2005), "Parking, People, and Cities," Journal of Urban Planning & Development, ASCE, pp. 233-244, December.

Pomerantz, Melvin (1999), "Benefits of Cooler Pavements," Lawrence Berkeley National Laboratory, posted presentation http://eetd.lbl.gov/HeatIsland/Pavements/Overview/index.html

Scott, K.I., Jim Simpson, and E. Gregory McPherson (1999), "Effects of Tree Cover on Parking Lot Microclimate and Vehicle Emissions," Journal of Arboriculture, Vol. 25, No. 3, pp. 129-142.

Table 2, http://www.eia.doe.gov/emeu/recs/recs2001/enduse2001/enduse2001.html

Taha, H., Chang, S-C, & Akbari, H. (2000), "Meteorological and Air Quality Impacts of Heat Island Mitigation Measures in Three U.S. Cities," Lawrence Berkeley National Lab Report No. 44222, April.

Thériault, M. Yan Kestens and François Des Rosiers (2005), "The impact of mature trees on house values and on residential location choices in Quebec City," http://www.iemss.org/iemss2002/proceedings/pdf/volume%20due/191.pdf

USCB (United States Census Bureau) (2005), "Table 3, California: Selected Economic Characteristics, 2003" last revised, June 28, 2005. http://www.census.gov/acs/www/Products/Profiles/Single/2003/ACS/Tabular/040/04000US063.htm

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B33*
ID NUMBER:	*SCAQMD-4*
TITLE:	*STRENGTHEN LIGHT-DUTY VEHCILE STANDARDS*
PROPONENT:	*SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4th quarter of 2012.

In September 2004 the California Air Resources Board approved regulations to reduce greenhouse gas emissions from new motor vehicles. The regulations apply to new passenger vehicles and light duty trucks beginning with the 2009 model year. The standards adopted by the Board phase in during the 2009 through 2016 model years. When fully phased in, the near term (2009-2012) standards will result in about a 22 percent reduction as compared to the 2002 fleet, and the mid-term (2013-2016) standards will result in about a 30 percent reduction.

The proposed strategy is the second phase of the 2004 regulation. This timing of 2012 will allow staff the time necessary to complete inventory research, interagency coordination, economic analyses, staff reports, stakeholder workshops, and public hearings to support the necessary regulation(s).

3. Early Action Description

Adopt new standards to phase in beginning in the 2017 model year (following up on the existing mid-term standards that reach maximum stringency in 2016). The technologies that might be employed include highly efficient hybrid vehicles, use of lightweight materials to reduce vehicle mass, and reductions in air conditioning related emissions through the use of cool paints, low-GWP refrigerants, or other approaches.

4. Potential Emission Reductions

The currently adopted standards call for about a 30 percent reduction of GHGs by 2016. Assuming that the new standards call for about a 50 percent reduction, phased in beginning in 2017, this measure would achieve about a 4 MMT reduction in 2020. The reduction achieved by this measure would significantly increase in subsequent years as clean new vehicles replace older vehicles in the fleet—staff estimates a 2030 reduction of about 27 MMT.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Not yet determined.

6. Technical Feasibility

The technologies involved in this strategy are either being proved or showing promising technical feasible. For example, available technologies that could be widely used on light-duty vehicles by 2012 include:

- Variable valve timing & lift
- Cylinder de-activation
- Gasoline direct injection - stoichiometric
- Turbocharging or cylinder deactivation
- 6-speed automatic and automated manual transmission
- Electric power steering
- Improved alternator
- More efficient, low-leak air conditioning
- Improved aerodynamics
- E85 vehicles

Additional technologies that could be widely used by 2016

- Extensive use of E85 vehicles
- Homogenous Combustion Compression Ignition (HCCI)
- Integrated Starter Generators (ISG)
- Camless Valve Actuation (CVA)
- Diesels
- Hybrids

7. Additional Considerations

In the near term, staff will continue to evaluate emerging technologies that have the potential to provide additional greenhouse gas reductions. Some technologies discussed under this subject can be implemented via separated early actions. Please refer to this report for detailed discussion.

8. Division: Mobile Source Control Division
Staff Lead: TBD
Section Manager: TBD
Branch Chief: TBD

9. References:

Work Plan for Potential GHG Reduction Measure, Air Resources Board 2-1.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B34*
ID NUMBER: *SCAQMD-5*
TITLE: *OFF HIGHWAY RECREATIONAL VEHICLE (OHRV) EVAPORATIVE EMISSIONS CONTROL*
PROPONENT: *2007 STATE IMPLEMENTATION PLAN AND SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

Staff recommends that this measure not be listed as an early action. Staff is aware of the potential climate benefit from hydrocarbon emission reductions, but additional developments are needed to address remaining scientific uncertainties regarding their climate impacts. Staff recommends that ARB continue to track the subject and further evaluation be conducted as appropriate. The strategy will remain on track for its air quality benefits.

3. Early Action Description

The OHRV category includes off highway motorcycles, ATVs, sand cars, and specialty vehicles. The OHRV evaporative emissions regulation will control primarily hydrocarbon emissions. Hydrocarbons are ozone precursors and ozone is a greenhouse gas. OHRVs will use proven automotive control technology including:

- Low Permeation Fuel Lines
- Low Permeation Fuel Tanks
- Carbon Canisters
- Fuel Injection

Additionally ARB will evaluate two implementation approaches:

1. A performance standard that will require equipment to be tested and meet a certain emission standard.
2. A design standard that will require equipment to use certified components. Each component must be tested and meet a certain emission standard.

4. Potential Emission Reduction

The OHRV regulation is expected to be implemented in 2012. When fully implemented in 2020, hydrocarbons are projected to be reduced by 11.3 TPD[1,2]. A reduction of hydrocarbon emissions will lead to a reduction in ozone. However, currently there is no model that projects the CO_2-equivalent warming impact for hydrocarbon emissions.

5. Estimated Cost / Economic Impacts and Impacted Sectors / Entities

An initial staff estimate of the increased cost to consumers to purchase an OHRV with evaporative controls is $350. It is expected that OHRV manufacturers will pass the cost of the regulation onto the OHRV consumer. When fully implemented in 2020 the total cost will be $588 million[3]. OHRV dealers may be adversely affected by an increase in equipment price of OHRVs.

6. Technical Feasibility

Potential technology that will control hydrocarbon emissions from OHRVs includes low permeation fuel tanks, low permeation fuel lines, carbon canisters, and fuel injection. These types of control technology have been proven on on-road vehicles for over 25 years. Recently evaporative controls have also been required on off-road categories such as land and garden equipment.

7. Additional Considerations

Currently ARB has aligned its regulatory approach with a U.S. EPA regulation that sets permeation standards for fuel tanks and fuel lines. However, ARB's OHRV regulatory initiative will evaluate the stringency of those standards to see if they can be tightened. ARB will also seek emission reductions from other sources within the category such as carburetors and running losses.

8. **Division:** Monitoring and Laboratory Division

Staff Lead: Pippin Mader
Section Manager: James Watson
Branch Chief: Manjit Ahuja

9. References

[1] Full implementation assumed at 95%

[2] All emission calculations based on ARB's Off-road 2007 Model and 75% control

[3] Controlled population of~1.68 million in 2020 times $350

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

2. Early Actions Strategy Name and Proponent

SUMMARY # *B35*
ID NUMBER: *SCAQMD-5*
TITLE: *DETERMINATION OF EVAPORATIVE EMISSIONS FROM PLEASURE CRAFT*
PROPONENT: *2007 STATE IMPLEMENTATION PLAN AND SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT*

2. Staff Recommendation

Staff recommends that this measure not be listed as an early action. Staff is aware of the potential climate benefit from hydrocarbon emission reductions, but additional developments are needed to address remaining scientific uncertainties regarding their climate impacts. Staff recommends that ARB continue to track the subject and further evaluation be conducted as appropriate. The strategy will remain on track for its air quality benefits.

3. Early Action Description.

The Pleasure Craft category includes inboard, outboard, sterndrive, and personal watercraft. The Pleasure Craft evaporative emissions control regulation will reduce hydrocarbon emissions. Hydrocarbons are ozone precursors and ozone is a greenhouse gas. Pleasure Craft will use proven automotive control technology including:

- Low Permeation Fuel Lines
- Low Permeation Fuel Tanks
- Carbon Canisters
- Fuel Injection

4. Potential Emission Reduction

The Pleasure Craft regulation is expected to be implemented in 2012. Hydrocarbon emissions are projected to be reduced by 16 TPD in 2012. When fully implemented in 2035[1,2], hydrocarbons are projected to be reduced by 53 TPD. However, currently there is no model that projects the CO_2-equivalent warming impact for hydrocarbon emissions.

5. Estimated Cost / Economic Impacts and Impacted Sectors / Entities

An initial staff estimate of the increased cost to consumers to purchase a boat with an evaporative control system is $350[3]. The estimated increased cost is minimal when compared to the current cost of a new boat. When partially implemented in 2020, the cost to consumers is projected to be $310 million. When fully implemented in 2035 the total cost to consumers is estimated at $1.13 billion[4]. There is no foreseeable adverse impact on any businesses or individuals.

6. Technical Feasibility

Potential control technology that will reduce hydrocarbon emissions from Pleasure Craft includes low permeation fuel tanks, low permeation fuel lines, carbon canisters, and fuel injection. These types of control technology have been proven on on-road vehicles for over 25 years. Recently evaporative controls have also been required on off-road categories such as land and garden equipment. Furthermore, a 2005 in-use study of Pleasure Craft retrofitted with carbon canisters conducted by the National Marine Manufacturers Association demonstrated technical feasibility for marine applications and lessened boat manufacturer concerns.

7. Additional Considerations

The proposal being developed does not seek to retrofit existing boats with control technology due to cost and safety issues. Because of their lengthy useful life, it may take up to three decades for the inventory of Pleasure Craft to become fully compliant subsequent to implementation of the regulation 2012.

8. Division: Monitoring and Laboratory Division
Staff Lead: Fredrick Burriell
Section Manager: James Watson
Branch Chief: Manjit Ahuja

9. References

[1] Full implementation assumed at 95%

[2] All emission calculations based on ARB's Off-road 2007 Model and 70% control reduction

[3] Cost estimates based on a per vehicle control technology cost of $350

[4] Controlled population of ~3.22 million in 2035 times $350.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B36*
ID NUMBER: *EA 3-3*
TITLE: *VESSEL SPEED REDUCTION*
PROPONENT: *AIR RESOURCES BOARD*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. At this time, staff is evaluating whether this is most appropriately managed as a regulatory item or a voluntary measure.

The staff recommends retaining the vessel speed reduction (VSR) measure as an early action for the following reasons:

- the need to gather additional information on the scope, emissions impact, cost, and environmental impacts of the measure; and
- the need for stakeholder input on whether a voluntary or regulatory approach should be taken.

Based on preliminary emissions estimates, the overall weight of evidence suggests that this measure would fall under the medium category for regulatory action (see subsection 4 for emission benefits).

3. Action Description

As part of our efforts under the Diesel Risk Reduction Plan, Goods Movement Emissions Reduction Plan, and Assembly Bill 32 - Greenhouse Gas Initiative, the Air Resources Board (ARB) staff is evaluating the need to develop an ocean-going VSR program. Ocean-going VSR is primarily a measure designed to reduce oxides of nitrogen (NOx) emissions, but also provides reductions in diesel PM emissions, oxides of sulfur (SOx) emissions, and carbon dioxide (CO_2) emissions.

Over the past six years, a VSR program has been in place at the Port of Los Angeles and Port of Long Beach (POLA/POLB). The program requests that vessels reduce their speed to 12 knots beginning 20 nautical miles (nm) off shore from the POLA/POLB. Currently, the POLB maintains a Green Flag Program which is an incentive program that offers reduced dockage fees for those vessels in compliance with VSR. The compliance rate for the POLB Green Flag Program is about 80 percent.

ARB staff has begun a technical assessment of the impacts associated with VSR for ocean-going vessels. As part of the technical assessment, staff will be evaluating emission reduction benefits of a VSR measure in and out of California ports and along the California coast within 24 nm, 40 nm, and 100 nm.

The staff assessment is in its very early stages. ARB staff held its first VSR workshop on July 12, 2007. At this workshop, ARB staff presented an overview of their activities related to the VSR assessment and shared some key elements needing industry's assistance. To conduct a full evaluation, ARB staff is in need of additional data to refine our emissions inventory, such as emission factors, speed data from ports other than POLA/POLB, as well as, an understanding of the operating cost impacts to the industry. ARB staff expects to release a draft technical assessment report with the results of their evaluation by the end of 2007. The evaluation in this report will be key to determining the need and best approach to implement a regulatory or a voluntary VSR measure.

4. Potential Emission Reductions

VSR is primarily a measure designed to reduce NOx emissions, but also provides reductions in diesel PM emissions, SOx emissions, and CO_2 emissions. ARB staff has estimated the potential emissions reductions as a result of implementing a statewide VSR program within 24 nm and 100 nm of the California coastline. This preliminary assessment is based on the emissions benefits estimated using emissions factors from the use of low sulfur (0.1%) marine distillate in marine main and auxiliary engines and 2006 port call data from the California State Lands Commission. Our preliminary assessment suggests that the implementation of VSR reduces pollutants such as NOx, diesel PM, and SOx by an average of 30 percent within 24 nm of the California coast. In addition to these criteria pollutant emission reduction benefits, if a VSR program is implemented at 24 nm, the potential CO_2 emission reductions in 2010 are estimated to be 0.62 million metric tons of CO_2 ($MMTCO_2$) and increasing to 0.97 $MMTCO_2$ by 2020. If a VSR measure was implemented at a distance of 100 nm, then the additional CO_2 emission reductions in 2010 are estimated to be approximately 0.5 $MMTCO_2$ and in 2020 approximately 0.83 $MMTCO_2$. These estimates exclude the emissions benefits already achieved by the POLA/POLB at a compliance rate of about 80 percent.

A VSR program at other ports, such as San Diego and Hueneme, may also provide emissions benefits, and to a lesser extent, San Francisco Bay Area ports. It is questionable whether a coastline VSR measure will achieve significant emission benefits.

The CO_2 emission reduction potential rating for a VSR measure within 24 nm of the California coast is estimated to be in the medium (>0.1 to 1.0 $MMTCO_2$) category.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The estimated costs and economic impacts of a regulatory or voluntary VSR measure have not been evaluated. A cost impact analysis for either a regulatory or voluntary VSR measure would need to include an estimate of the increase in the cost of operation to shipping companies due to reducing speeds in and out of California ports and along the coastline, increase cost of fuel used in auxiliary engines due to increased time traveling to port versus the fuel savings due to decreased ship engine power requirements, costs borne by the industries/terminals affected by a VSR measure, costs to ports in developing infrastructure improvements (i.e., radar equipment), and costs needed for enforcing any speed reduction measure. In addition to the POLA/POLB, staff is currently evaluating other major ports such as those in the Bay Area, San Diego, and

Hueneme. Staff is also looking at the impact to the industry if VSR was implemented while transiting along the California coastline within 24 nm and 100 nm.

Voluntary measures, such as seen in the POLB Green Flag Incentive Program, may require port and terminal-specific costs. Some of the incentives of this program include reduced dock fees for those complying with the VSR program and tariff reduction incentives. The San Pedro Bay Clean Air Action Plan adopted in 2006 for the POLA/POLB, have estimated the costs of controls for the voluntary VSR measure to be approximately 4.4 million dollars for 2010. The POLA/POLB has already committed to fund a maximum of 11.3 million dollars through 2010/2011 for each port to implement the port's Clean Air Action Plan.

6. Technical Feasibility

A voluntary VSR program has been in place at the POLA/POLB over the past six years. The POLA/POLB accounts for over half of the port calls statewide. This VSR program requested ships to voluntarily reduce their speed to 12 knots at a distance of 20 nm from the California coast. Currently, the POLB maintains the Green Flag Incentive Program which offers reduced dockage fees and environmental awards for vessels that voluntarily reduce their speeds in and out of the POLB. This program has been very successful as shown by its current 80 percent compliance rate. A VSR program is clearly technologically feasible. However, reducing speeds for an extended period of time transiting along the coast has not been evaluated. There is some information that maintaining a slower speed for extended distances may cause adverse mechanical effects on a vessel's main engine. This analysis will need further evaluation.

7. Additional Considerations

- With the exception of the voluntary programs at the POLA/POLB, no federal or other state VSR regulations are currently in place.
- VSR activity falls under ARB jurisdiction and legal authority. ARB's authority to regulate emissions beyond 3 nm is being challenged in court. Significant legal challenges are likely if the ARB elects to implement a VSR regulation beyond 24 nm.
- At this time, we are evaluating the feasibility of both regulatory and voluntary measures. Both approaches will consider speed reductions from direct travel in and out of major ports and evaluate the inclusion of transiting up and down the California coast. Voluntary approaches can include agreements or incentive programs between port and terminal operators, vessel owners and operators, and government agencies. Regulatory measures would take the form of an airborne toxic control measure.

8. Division: Stationary Source Division
Staff Lead: Hafizur Chowdhury
Section Manager: Robert Krieger
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B37*
ID NUMBER: *ENVIRO-2*
TITLE: *ANTI-IDLING ENFORCEMENT*
PROPONENT: *ENVIRONMENTAL STAKEHOLDERS*

2. Staff Recommendation

This measure is recommended for addition to the list of early actions. The Board date for consideration of this non-regulatory item would be the 4th quarter of 2008.

This strategy will ensure that climate change benefits are realized from an existing anti-idling rule. It is believed that the 0.7 million metric tons per year CO_2 reduction listed in the 2005 staff report for the anti-idling rule have not yet been claimed.

Summary: Restricting vehicle idling (in this case, heavy-duty commercial diesel vehicles) reduces the amount of fuel burned which in turn, causes fewer emissions of greenhouse gases. Staff recommends that this measure become an early action item for the following reasons:

1) An anti-idling regulation is currently in place;
2) An enhanced version of the current anti-idling regulation is slated to commence enforcement on January 1, 2008; and
3) Proposed legislation (Assembly Bill [AB] 233, Jones), if adopted, would authorize and require ARB to further enhance its enforcement of the anti-idling regulation. This bill calls for an enhanced enforcement plan to be adopted by the Board by January 1, 2009.

If this bill is not enacted, staff could include enforcement enhancements through a Board action directed at reviewing and amending the current anti-idling regulation (with Board hearing no sooner than 2011).

3. Early Action Description

The burning of diesel fuel contributes to greenhouse gas emissions. This strategy will reduce greenhouse gases by reducing the amount of fuel burned through unnecessary idling. AB 233 calls for adoption of an enhanced enforcement plan that would be heard by the Board as a non-regulatory item.

1) ARB adopted a diesel particulate air toxic control measure (Title 13 of the California Code of Regulations, Section 2485) in June 2004 to control idling of diesel-fueled commercial motor vehicles. Enforcement commenced the following year. This rule prohibits, with some exceptions, the idling of diesel-fueled commercial motor vehicles for more than five minutes, and applies to both trucks and buses greater than 10,000 lbs. gross vehicle weight. The measure also

prohibits operation of a diesel-fueled auxiliary power system for more than five minutes within 100 feet of individual or multi-family housing units. The penalty for violating the idling regulation is currently a minimum of $100.

2) In October 2005, the Board approved an additional regulatory measure that eliminated the exemption for new and in-use trucks with sleeper berths starting in January 2008, thus requiring sleeper berth trucks to shut down and use alternative cab climate control technologies. In addition, the Board approved an amendment requiring that all new California-certified 2008 and subsequent model year heavy duty diesel engines be equipped with a non-programmable engine shutdown system that automatically turns off the engine after five minutes of idling. Enforcement of these provisions will begin in 2008.

3) AB 233, Jones, currently pending approval by the California Legislature, calls for:

   a) Enhanced field enforcement of anti-idling and other ARB regulations. AB 233 would require ARB to review existing enforcement regulations and adopt a plan for enhanced and coordinated enforcement of these regulations by January 1, 2009. Implementation of the plan would address staffing needs, goals for inspection efforts, education and training. Increases in field enforcement would flush out additional violators and give them fewer opportunities to disobey the regulation.

   b) Increased penalties for violations of anti-idling regulations. It is assumed that increasing the penalty from $100 to $300 per violation will increase the deterrent effect, resulting in improved compliance.

   c) Restriction on registrations of heavy-duty diesel vehicles with uncorrected idling violations. This would serve as an additional enforcement tool to encourage compliance.

4. Potential Emission Reductions

The emission numbers in the tables below do not represent an additional benefit due to enhanced enforcement. Rather, the numbers show the benefits of 100% compliance with the existing anti-idling rule. Enhanced enforcement is necessary in order to achieve a high compliance rate.

The elimination of non-essential diesel fueled vehicle idling reduces greenhouse gases as reported in ARB's anti-idling program staff reports. According to ARB's Initial Statement of Reasons for Proposed Rulemaking dated September 2005, the proposed sleeper berth anti-idling regulation amendments alone will reduce CO_2 emissions by nearly 1,751 metric tons per day (MTPD) and 0.6 million metric tons per year (MTPY) in 2010, and 2,068 MTPD and 0.7 million MTPY in 2020. (See www.arb.ca.gov/regact/hdvidle/isor.pdf, page 46). Enhanced enforcement of these anti-idling regulations will reduce greenhouse gas emissions by ensuring that the intended benefit of 0.7 million MTPY is fully realized by 2020.

The tables below provide the estimated statewide emissions benefits projected in metric tons per year for the currently enforced anti-idling regulation and the sleeper berth exemption amendments to these regulations. However, these benefits assume 100% compliance. History has shown that no program achieves 100% compliance and that enhanced enforcement does lead to higher compliance rates. Based on a relatively small sample of idling inspections, the current program's rate of compliance is approximately 95%. However, given the limited number of idling inspections (due to resource constraints), it is assumed that this is not representative of statewide compliance rates.

Estimated Statewide Idling Emission Benefits - Non-Sleeper Trucks (Metric Tons/Year) – Beginning in 2005

	PM	NO_X	HC	CO	CO_2
CA Registered	151	4717	671	2631	312,344

Source: ARB's Initial Statement of Reasons for Proposed Rulemaking, July 22, 2004.

2010 Estimated Statewide Idling Emission Benefits – Sleeper Trucks Only

Baseline Emissions (Metric Tons/Year) Calendar Year 2010

	Vehicles	NO_X	ROG	PM	CO_2
CA Registered Sleeper Trucks	30,161	6570	694	128	397,485
Out-of-State Sleeper Trucks	45,241	10,950	840	113	596,045
Total Baseline	75,402	17,520	1533	241	993,530

Emission Reductions (Metric Tons/Year) Calendar Year 2010

	Vehicles	NO_X	ROG	PM	CO_2
CA Registered Sleeper Trucks	30,161	5475	621	88	255,135
Out-of-State Sleeper Trucks	45,241	9490	730	55	383,980
Total Baseline	75,402	15,330	1387	139	639,115

2020 Estimated Statewide Idling Emission Benefits – Sleeper Trucks Only

Baseline Emissions (Metric Tons/Year) Calendar Year 2020

	Vehicles	NO_X	ROG	PM	CO_2
CA Registered Sleeper Trucks	35,652	8760	657	55	470,120
Out-of-State Sleeper Trucks	53,478	12,775	913	26	705,180
Total Baseline	89,130	21,535	1606	81	1.18M

Emission Reductions (Metric Tons/Year) - Calendar Year 2020

	Vehicles	NO_X	ROG	PM	CO_2
CA Registered Sleeper Trucks	35,652	7300	584	26	301,490
Out-of-State Sleeper Trucks	53,478	11,315	876	7.3	453,695
Total Baseline	89,130	18,615	1460	33	754,820

Source: ARB's Initial Statement of Reasons for Proposed Rulemaking, September 1, 2005

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The current anti-idling regulations provide for savings of approximately $100 million per year in reduced fuel and maintenance costs. The sleeper berth exemption amendments to these regulations provide an additional annual savings of approximately $20 million per year in reduced fuel and maintenance costs. The sleeper berth exemption also is projected to save approximately 70 million gallons of diesel fuel per year.

To comply with the sleeper berth exemption amendments, vehicle owners may spend between $1,000 and $10,500 depending on the type of alternative power selected and the application needed. However, it is expected that vehicle owners will recover their initial investments over time through the fuel and maintenance savings discussed above. Although ARB estimates cost recovery times to range between 8 months and 3 years, actual recovery times will solely depend on the alternative(s) selected and the amount of time spent at idle. Financial incentives may be available for qualified zero-emissions technologies through the Carl Moyer Program.

Costs to State – If enhanced enforcement is to be achieved, additional resources will be necessary to increase enforcement presence.

6. Technical Feasibility

Technologies that will allow vehicle operators to maintain cab comfort while not running the vehicle's main engine are currently available. Some of these technologies are diesel-fueled auxiliary power systems, fuel-fired heaters, battery-electric auxiliary power systems, vehicle-battery-powered systems, truck stop electrification (on-board and off-board power infrastructure), and thermal energy storage systems.

7. Additional Considerations

A number of states have similar laws and some are more stringent than California's current law. However in 2008, California's law will no longer exempt idling of a vehicle's main engine while the operator sleeps in a sleeper berth.

This existing rule can be enforced by ARB staff, as well as by peace officers and air district personnel. This strategy is not a regulatory item. If AB 233 is approved, it calls for ARB to adopt a comprehensive enforcement plan by January 1, 2009.

AB 233 has not yet been approved (as of August 15, 2007).

8. Division:	Enforcement Division
Staff Lead:	Nancy O'Connor
Section Manager:	Judy Lewis
Branch Chief:	Paul E. Jacobs

9. References:

Assembly Bill 233 of 2007, Jones.

Senate Transportation & Housing Committee Analysis of AB 233, June 1, 2007.

ARB webpage: http://www.arb.ca.gov/msprog/truck-idling/truck-idling.htm

ARB webpage: http://www.arb.ca.gov/regact/hdvidle/isor.pdf

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *B38*
ID NUMBER: *ARB 4-4*
TITLE: *SF_6 REDUCTIONS FROM THE NON-ELECTRIC SECTOR*
PROPONENT: *STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure is recommended for addition to the list of discrete early actions. The Board date for consideration of this item is anticipated in 1st quarter of 2009.

The staff recommends developing regulations that ban the use of sulfur hexafluoride (SF_6) for non-electricity sector/semiconductor applications where technologically feasible and cost-effective alternatives are available. As part of the assessment, strategies for achieving voluntary reductions will also be evaluated.

3. Early Action Description

This strategy applies to uses of SF_6 other than the electrical utility industry and the semiconductor industry, which will be evaluated under separate strategies. The largest non-utility industry, non-semiconductor industry uses of SF_6 identified by the staff to date include the magnesium manufacturing and casting operations, air quality tracer studies, and a gas for testing laboratory hoods to ensure worker safety and that Cal-OSHA ventilation requirements are met. Other uses cited include accelerators, leak detection, optical fiber production, glazing, medical, and refining, but the extent of these uses in California is currently unknown. The staff plans to identify all of the uses of SF_6 in California, and the amount used, as part of its evaluation. As part of the regulatory development process, the staff will assess other uses of SF_6, the associated emissions, mitigation options as well as cost to determine whether action is warranted. The U.S. EPA has formed a “Magnesium Industry Partnership” to voluntarily phase-out the use of SF_6 in the magnesium industry by the end of 2010, so a regulation of this industry may be unnecessary. Nationwide, emissions from the magnesium industry are about 2.7 $MMTCO_2E$ per year. There are currently only three companies in California that have magnesium production and casting operations and that are members of the EPA partnership. The SF_6 emissions from these companies are currently unknown. But scaling the nationwide estimated of 2.7 $MMTCO_2E$ per year to California by the number of production facilities gives a California number of about 0.09 $MMTCO_2E$ per year.

The staff envisions banning the use of SF_6 in non-utility, non-semiconductor applications where safe, cost-effective alternatives are available. These applications may include magnesium production and casting operations, air quality tracer gas studies, and ventilation tests for laboratory hoods. The staff will investigate other possible uses of

SF_6 during the development of the regulations. It is important that all uses of SF_6 be investigated and considered given its high GWP, particularly if the application is one in which the compound is deliberately emitted, such as tracer gas applications. One pound of SF_6 emitted is equivalent to about 10 metric tons of carbon dioxide, from a global warming perspective.

4. Potential Emission Reductions

Statewide Emission Inventory

2020 GHG Emission Inventory: It is estimated that, nationwide, about 10 percent of the total SF6 is used in applications other than the utility and semi-conductor industries. It is also estimated that about half of this 10 percent is used in the magnesium industry. The most recent estimate of emissions in California from both electric utilities and semiconductor manufacturing operations is about 1.6 MMTCO2E per year (CEC, 2006). Assuming that the proportion of SF6 emitted to the amount of SF6 used in other applications is the same as that for the utility and semiconductor applications, emissions from the other applications would be about 0.18 MMTCO2E per year in California. Nationwide, SF6 emissions from the magnesium industry are currently about 2.7 MMTCO2E per year. Scaling this number down to the number of production facilities in California gives a California emission estimate of about 0.09 MMTCO2E per year. However, if the U.S. EPA Magnesium Industry Partnership is successful in phasing out the use of SF6 by the end of 2010, the emissions from the magnesium industry will be zero in 2020. This leaves at least 0.09 MMTCO2E per year from other applications such as tracer studies and laboratory hood tests. However, it is likely that emissions from these other applications are somewhat higher than 0.09 MMTCO2E per year due to the fact that the ratio of amount of gas emitted to amount used in these applications is higher than that for utilities. In the utilities, the gas is emitted gradually as it escapes from enclosed systems, while in tracer studies and hood tests it is emitted instantaneously.

Anticipated 2020 Reductions: It is anticipated that all, or nearly all, of the emissions from non-utility, non-semiconductor use would be eliminated under the staff proposal. Therefore, the reductions are estimated to be on the order of 0.1-0.2 MMTCO2E per year.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Alternative gases have been identified for magnesium production and casting operations, and for laboratory hood tests performed to ensure adequate ventilation rates. The cost and economic impacts of using these gases will be evaluated during the regulatory development process, but the difference in cost would be expected to be modest.

6. Technical Feasibility

As part of the U.S. EPA's Magnesium Industry Partnership, magnesium production and casting operations have been developing the use of gases other than SF_6 to provide the cover gas protection provided by SF_6. The partnership is attempting to meet the goal of phasing out SF_6 by 2010.

The staff will investigate both the technical and economic feasibility of using alternative gases in air quality tracer studies and laboratory hood tests done to comply with Cal-OSHA ventilation standards. The technical and economic feasibility of using alternative gases will also be evaluated for any other use of SF_6 identified by the staff.

7. Additional Considerations

Some of the factors that will need to be carefully evaluated include determining if there are alternative gases as safe and effective as SF_6 with lower lifecycle GHG emissions. To the extent that alternatives are available, staff would also investigate whether a voluntary measure such as a voluntary phase-out program would be as effective as a regulatory approach.

Affected Entities: Companies that produce magnesium or magnesium castings, air pollution and air quality researchers, universities, industries, and other institutions that have laboratory hoods that are subject to Cal-OSHA standards.

Trade Associations: North American Die Casting Association (DADCA), Compressed Gas Association, Associations which include industrial hygienists. American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE).

Government Agencies to coordinate with: U.S. EPA, Cal-OSHA

Proposed Board Hearing Date: January, 2009

8. Division:	Research Division
Staff Lead:	Kevin Cleary Greenhouse Gas Technology and Field Testing
Section Manager:	Mike FitzGibbon
Branch Chief:	TBD

9. References:

Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, United States Environmental Protection Agency, April 15, 2007

Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004, California Energy Commission, December, 2006

Communications with Cal-OSHA staff (Mike Horowitz)

Nationwide SF_6 Sales by End Use: 1961-2003, Fourth International Conference on SF_6 and the Environment, November, 2006, the Rand Corporation

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B39*
ID NUMBER:	*N/A*
TITLE:	*REDUCTION OF HIGH GWP GHGs USED IN CONSUMER PRODUCTS*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure is recommended for addition to the list of discrete early actions. The Board date for consideration of this item is anticipated in 4^{th} quarter of 2008.

Some data regarding emissions of greenhouse gases is available from a recent survey of consumer products, which may represent possible reductions within the discrete early action timeframe. Manufacturers are also currently being surveyed to determine the extent of usage of high global warming potential (GWP) gases in several more categories of consumer products. These future survey results may lead to additional strategies with emission reduction potential that can be pursued after the deadline for discrete early action items.

3. Early Action Description

Consumer product formulations may be modified to reduce or eliminate the use of greenhouse gases with high GWP. Gases of interest include HFCs, HCFCs, HFEs, carbon dioxide, and nitrogen oxides, which are used as propellants in tire inflators, electronics cleaners, dust removal products, hand held sirens, hobby guns (compressed gas), party products (foam string), and other formulated consumer products. The objective of this discrete early action strategy would be to reduce the impact of high GWP GHGs used in these products when alternative formulations are available. For example, one possible form of the strategy would be to require switching when feasible from using a high GWP GHG such as HFC-134a (GWP=1300) to a GHG with a lower GWP such as HFC-152a (GWP=120). The Consumer Products Program is implemented through regulations and this proposed new discrete early action strategy would occur as part of that regulatory process.

4. Potential Emission Reductions

ARB staff estimate a potential emissions reduction of up to 0.25 MMTCO2E from consumer products. ARB is currently surveying consumer product manufacturers for specific information on product ingredients. Categories listed above that may contain high GWP GHGs are included in the survey. The required submission date for the survey is November 21, 2007. Analysis of survey data will provide an accurate estimate of potential emission reductions.

In 2002, A. D. Little reported that the annual North American consumption and emissions of HFCs in consumer products was 10 MMTCO2E with the two highest-use products being dust removal products and tire inflators at 4.7 and 3 MMTCO2E, respectively. California's population is about eight percent of the North American population. Assuming product usage is similar across North America and scaling with population, HFC emissions from consumer products in California are about 0.8 MMTCO2E. This value seems to be confirmed by initial results from ARB's 2003 Consumer and Commercial Products Survey.

5. Estimated Costs / Economic Impacts and the Impacted Sectors/ Entities

Costs per MTCO2E are not available at this time. However, other regulations in the Consumer Products Program have been implemented in a cost effective manner. The manufacturers would bear the cost of formulation changes, then presumably pass the cost on to the consumer. Each product category would be fully evaluated for estimated costs as regulations are implemented. Any potential disproportionate impacts would depend on the individual product and whether it is used to a greater extent by any given sector of the population.

6. Technical Feasibility

The ARB staff believes technology is available to make changes in some consumer product categories to decrease the use of high GWP GHGs without increasing other emissions. ARB has not previously worked with representatives of certain segments of the industry, such as manufacturers of hobby guns that use compressed gas, so determination of the technical feasibility of GHG reductions in some applications cannot be made at this time.

7. Additional Considerations

Consumer Products are under ARB jurisdiction with legal authority for regulation. New regulations are scheduled to be heard by the Board in 2008. These regulations may address the use of high GWP GHGs in several product categories. An initial public meeting for the development of this regulation is scheduled for August 29, 2007. These regulations, already under development, will meet the statutory deadline for discrete early actions. Development of regulations for other categories of consumer products would fall under the Scoping Plan of The California Global Warming Solutions Act of 2006.

8. Division: Stationary Source Division
Staff Lead: Jessica Dean
Section Manager: David Mallory
Branch Chief: Janette Brooks

9. References:

Arthur D. Little, Global Comparative Analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire Protection Applications, Final Report to the Alliance for Responsible Atmospheric Policy, March 21, 2002

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*B40*
ID NUMBER:	*N/A*
TITLE:	*COLLABORATIVE RESEARCH TO UNDERSTAND HOW TO REDUCE GREENHOUSE GAS EMISSIONS FROM NITROGEN LAND APPLICATION*
PROPONENT:	*STAKEHOLDERS SUGGESTIONS*

2. Staff Recommendation

This measure is recommended for addition to the list of early actions. The Board date for consideration of this item is anticipated in 4th quarter of 2010.

3. Early Action Description

Staff analysis suggests that nitrogen land application may be a significant source of nitrous oxide, which is a potent greenhouse gas. In order to reduce greenhouse gases while benefiting agricultural systems, landscaping and other uses staff needs to identify methodologies for better characterizing California's nitrogen cycle.

An important first step to better characterizing the relationship between nitrogen land application and nitrous oxide formation in California agriculture, landscaping and other uses as well as opportunities for emission reductions is a collaborative research effort with stakeholders. The research is expected to focus on identifying optimal ways to reduce nitrous oxide emissions while increasing soil retention of nitrogen for plant uptake. Factors such as the total acreage of crop field, the annual amount and type of nitrogen applied, the method of application, soil properties, the irrigation regime, and drainage conditions can all play a role in characterizing nitrous oxide formation and would therefore be expected to be studied as part of the work. As part of the research the ARB will collaborate with the California Department of Food and Agriculture, Department of Pesticide Regulation, commodity groups, and other stakeholders. The research is expected to ultimately support the development of guidance to improve the characterization of nitrous oxide emissions from nitrogen land applications as well as identify effective strategies for emission reductions.

4. Potential Emission Reductions

The potential benefit of nitrous oxide emission reductions following from the research effort requires further assessment and is therefore to be determined. However, given the current nitrogen fertilizer use efficiency and portfolio, possible reductions from guidance that builds on the research may be on the order of 1 $MMTCO_2E$.

5. Estimated Costs / Economic Impacts and the Impacted Sectors/ Entities

Entities expected to participate in the collaborative research effort as well as the subsequent development of guidance includes farm owners and operators, nitrogen fertilizer manufacturers and distributors, the California Department of Food and Agriculture, Department of Pesticide Regulation, Regional Water Boards, commodity groups, and other stakeholders. The estimated costs of the research are to be determined as are any costs or savings associated with implementing subsequent guidance.

6. Technical Feasibility

The ARB has an established track record of collaborating with stakeholders to ensure that high quality research is conducted and that the research facilitates the identification of effective mitigation strategies. It is anticipated that the necessary expertise to conduct the research can be secured via a contract with in-state experts.

7. Additional Considerations

The ARB will coordinate with the California Department of Food and Agriculture, Regional Water Control Boards, and local air quality management districts in their efforts related to Nutrient Management Plans.

8. Division:	Planning and Technical Support Division/Research Division
Staff Lead:	TBD
Section Manager:	TBD
Branch Chief:	TBD

9. References:

Blaylock, A.D., R. D. Dowbenko, J. Kaufmann, G. D. Binford, and R. Islam. 2004. ESN® controlled-release nitrogen for enhanced nitrogen efficiency and improved environmental safety. Picogram and Abstracts, America Chemical Society, Philadelphia, PA. http://membership.acs.org/a/agro/Picogram/PicogramV67Fall2004.pdf

Brontrager, B. 2001. Stretch your 'N' dollars using urease, nitrification inhibitors. http://www.agprofessional.com/croptalk.php?id=1135

Burt, C. M., K. OConnor, and T.A. Ruehr. 1995. Fertigation. pp. 320Irrigation Training and Research Center. California Polytechnic State University, San Luis Obispo, CA.

Li, C.S., W. Salas, and M. L. Huertos. 2004. Quantifying carbon dynamics and greenhouse gas emissions in agricultural soils of California: A scoping study. PIER Project Report, P500-04-038. California Energy Commission, Sacramento, California. (http://www.climatechange.ca.gov/research/options/pdfs/2004-10-08_500-04-038.pdf).

Scholefield, D. and N.M. Titchen. 1995. Development of a rapid field test for soil mineral nitrogen and its application to grazed grassland. Soil Use and Management 11 (1), 33–43.

APPENDIX C – Staff Evaluation of Remaining Previously Approved Early Actions

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY # *C01*
ID NUMBER: *ARB 2-2*
TITLE: *STATIONARY AGRICULTURAL ENGINE ELECTRIFICATION*
PROPONENT: *AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This strategy was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this strategy is recommended.

However, given that electrification of stationary agricultural diesel engines must be considered on a case-by-case basis due to operational and cost issues, a control measure to require the electrification of these engines is impractical and cost-prohibitive for many growers (see Parts 5 and 7 for additional information). Accordingly, the approach currently being implemented is an outreach effort and therefore a Board hearing is not anticipated.

3. Early Action Description

As part of the outreach being conducted for the amendments to the airborne toxic control measure (ATCM) for Stationary Compression-Ignition Engines, ARB staff is working with the local air districts to encourage replacement of diesel engines with electric motors and to take advantage of incentive funding opportunities. Outreach materials and workshops will provide information regarding ATCM compliance options, including electrification. ARB staff is encouraging growers to consider switching to electric motors, especially in those cases where irrigation pumps are located in close proximity to residential areas, schools, and hospitals.

4. Potential Emission Reductions

This effort is expected to have a low emission reduction potential. Based on discussions with the agricultural community and electric utilities, up to 20 percent of existing stationary diesel agricultural irrigation pump engines are expected to be replaced with electric motors by 2020. This would result in a 2020 reduction of approximately 0.1 million metric tons of carbon dioxide. Given the compliance schedule in the ATCM and uncertainty regarding some incentive programs, staff is unable to estimate reductions for 2010 at this time.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

ARB staff estimates the cost to electrify stationary agricultural engines at about $26 million (8,600 pump engines x 20 percent x $15,000 (average capital cost of an electric motor)). This estimate does not account for possible additional line extension and/or electrical hook-up charges (highly variable for agricultural electric customers depending on location, crop, well-depth, and other variables), which are likely to be cost prohibitive for many growers in remote areas. The estimate also does not account for any potential incentive funds that may be available to switch from diesel- to electric-powered agricultural irrigation pumps as these funds are limited and available on a first-come, first-served basis.

6. Technical Feasibility

Outreach efforts will encourage the use of electric motors, which are established and proven in agricultural operations. Approximately 82 percent of all stationary agricultural irrigation pumps in California are currently powered by electric motors, 15 percent are diesel-powered, and three percent are powered by other means (e.g., natural gas, liquefied petroleum gas, propane, butane, or gasoline).

7. Additional Considerations

The Board approved the amendments to the ATCM for Stationary Compression-Ignition Engines at the November 2006 public hearing. The amendments contain emission performance standards for agricultural engines but do not mandate electrification or any other specific compliance option. As explained in the September 2006 staff report for the ATCM, the Board had previously directed ARB staff to investigate the opportunities and challenges associated with replacing California's existing population of stationary diesel agricultural engines with electric motors. During the investigation, ARB staff identified many variables associated with farm and ranch electrical power use in California. These variables include irrigation method and schedule, availability of surface water, well pumping depth, quantity of water needed, fuel costs, electricity costs, and electrical infrastructure proximity and adequacy. Because of these variables, ARB staff concluded that any decision about the desirability or difficulty of converting stationary diesel agricultural engines to electric motors must be made on a site-by-site basis. Nonetheless, ARB staff believes that most engines will be replaced with new cleaner certified diesel engines or with electric motors. Retrofit and alternative fuels are other potential means of compliance. Staff is unable to predict which compliance option farmers will choose.

8. Division: Stationary Source Division
Staff Lead: Jon Manji
Section Manager: Richard Boyd
Branch Chief: Dan Donohoue

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C02*
ID NUMBER:	*ARB 2-4*
TITLE:	*REDUCTION OF PERFLUOROCARBONS (PFCs) FROM THE SEMICONDUCTOR INDUSTRY*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, it is recommended that this measure be reclassified as a discrete early action. The Board date for consideration of this item is anticipated in 4th quarter of 2008.

3. Early Action Description

The semiconductor industry uses PFCs primarily for etching circuits in silicon wafers and cleaning chemical vapor deposition tool chambers where thin films of chemicals are laid down onto silicon wafers. During these processes, a portion of the PFC gases used is released to the atmosphere.[1] There are four technologies industry has either employed or considered to reduce PFC emissions from semiconductor production:

- Process Optimization (optimizing the use of PFCs, such as in the chamber cleaning process);
- Alternative Chemistry Development;
- Emission Abatement; and
- Recovery/Recycling (separation of fluorinated compounds from other gases for further processing and reuse).

This discrete early action item will consider mandating the process optimization and alternative chemistry development technologies currently in use by some manufacturers. ARB would also evaluate the technical and economic feasibility of requiring emissions abatement and recovery/recycling strategies that may further reduce PFC emissions.

A few California manufacturers currently participate in voluntary national efforts to reduce PFC emissions to 10 percent below 1995 levels by 2010. A 2001 Memorandum of Understanding (MOU) agreement with the U.S. EPA provides details of these efforts.[2] Only three of 93 California manufacturers (about 15 percent of California production) participate in the MOU agreement.[3] Manufacturers and the U.S. EPA reached the agreement well before the adoption of Assembly Bill 32. Consequently, the State and federal courses of action have different goals and timeframes and information on any actions being taken by the remaining California companies to reduce PFC emissions is limited. A survey of the industry will be necessary to improve the accuracy of the emissions data.

4. Potential Emission Reductions

ARB staff proposed a GHG reduction goal of 0.5 $MMTCO_2$ equivalent in 2020 for the semiconductor industry in the April 2007 early actions report.[4] This goal will be further evaluated based on survey results from the industry and other data that become available over the next few months.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The complete cost of this regulation has not been determined at this time. For process optimization, higher costs could be incurred by older fabrication facilities as process parameters such as chamber pressure, temperature, cleaning gas flow rates and gas mixture ratios are changed to reduce gas use. Alternative chemistry development is expected to result in minor cost impacts as the cost of alternative gases would be about the same as PFC gases. The manufacturers could pass on any additional costs to the consumers through higher product prices. The significance of this impact is not known.

6. Technical Feasibility

The technical feasibility of two of the four technology options for reducing PFC emissions within the semiconductor industry is fairly well known at this time. Two technologies currently used by manufacturers are:

- Process optimization
  This technology reduces the amount of PFCs used and has been primarily applied to the chamber cleaning process because of high use of PFC gases for cleaning.
- Alternative Chemistry Development
  Nitrogen trifluoride (NF_3) has been used as a substitute for hexafluoroethane (C_2F_6) in the chamber cleaning process to reduce PFC emissions since NF_3 is more effectively destroyed in the process.

Two technologies that would be further evaluated are:

- Emissions abatement
  Commercially available technologies can be applied to the chamber cleaning or the etching process to reduce emissions. High temperature and catalytic oxidation and plasma destruction are the most common technologies used to abate PFCs, but little is currently known about the extent of use by California manufacturers. Furthermore, the performance of abatement systems can vary greatly depending on the abatement device and process parameters, such as temperature and PFC gas flow rates.
- Recovery/Recycling
  These technologies have not achieved as much success as others as they are more costly or require more maintenance. The recovered compounds that are separated from other gases contain more impurities than virgin chemicals and are less likely to be used by the industry.

7. Additional Considerations

Additional considerations that pertain to the measure include:

This item is regulatory and falls under ARB jurisdiction. ARB has the legal authority to pursue this discrete early action item and the Climate Action Team supports further PFC reductions by the semiconductor industry.[5] Staff recommends that this item be presented to the Board within 18 months.

Leakage Considerations: The movement of semiconductor production facilities and older equipment from California to regions beyond California may result in leakage effects. The Semiconductor Industry Association (SIA) has indicated that California semiconductor manufacturing has been in decline over the last decade. The reasons vary from high capital costs, to tax advantages offered by other state and foreign governments, to lower financial risks associated with overseas foundry manufacturing compared to self-manufacture. The illustration provided by SIA is that from 1995 to 2006, three of the six MOU California companies ceased manufacturing operations. The corresponding decline in emissions was that California went from representing nearly 8 percent of U.S. emissions to just 3 percent. Staff needs to determine if the decline in California's emissions represents a shift of PFC emissions to other countries such as China. If so, we will need to determine if those manufacturers are using older equipment sold by California firms which may result in high emissions.

Affected Entities
Industry:

- Semiconductor fabrication industry
- Semiconductor Industry Association

Government:

- Local air pollution control districts
- California Energy Commission
- U.S. EPA

8. Division: Stationary Source Division
Staff Lead: Dale Trenschel
Section Manager: Terrel Ferreira
Branch Chief: Barbara Fry

9. References:

1. Emission Reduction Opportunities for Non-CO2 Greenhouse Gases in California, Public Interest Energy Research Program: Final Project Report, California Energy Commission, July 2005.

2. Memorandum of Understanding between the Semiconductor Industry Association (SIA) and the United States Environmental Protection Agency, January 2001.

3. Internal estimate, spreadsheet filename cost.xls, 2007.

4. Proposed Early Actions to Mitigate Climate Change in California, Air Resources Board, April 20, 2007.

5. Climate Action Team Report to Governor Schwarzenegger and the Legislature, California Environmental Protection Agency, March 2006.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C03*
ID NUMBER:	*ARB 2-5*
TITLE:	*FOAM RECOVERY/DESTRUCTION PROGRAM*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4th quarter of 2011.

This timing will allow staff the time to complete inventory research[1], interagency coordination, economic analyses, staff reports, stakeholder workshops, and public hearings to support the necessary regulation(s).

An alternative or complimentary approach may include establishing a voluntary agreement for recovery and destruction for certain foams, if the agreement can be implemented more cost-effectively and can be expected to yield similar CO_2E benefits as mandatory compliance.

3. Early Action Description

This strategy involves a regulatory measure(s) to implement a program to recover and destroy high-GWP insulating foams from buildings, other construction/demolition (C/D) waste, and appliances at end-of-life (EOL). The appliance foam recovery would be coordinated with the US EPA, as they have implemented a similar, voluntary program with some utility providers[2].

Many foams contain high-GWP GHG blowing agents, especially older insulating foams used in appliances and buildings, that contain chlorofluorocarbon (CFC) blowing agents such as CFC-11 (100-year direct GWP of 4,600).

Currently, foams are either broken (building panels) or shredded (appliances) and landfilled; at this time, no federal or state laws require that foams containing ozone depleting substance (ODS) or other high-GWP blowing agents in the foam be removed and destroyed[3].

Foam recovery from appliances may either be done manually, or as part of a fully automated recovery system in which appliance refrigerant is removed/de-gassed, the appliance is

[1] Inventory work in this area is expected to be complete by late 2009.
[2] Responsible Appliance Disposal program, or RAD: http://www.epa.gov/ozone/snap/emissions/radp.html
[3] Although refrigerant removal is required at appliance EOL under federal and state law, it is unknown at this time whether foam and refrigerant recovery would be performed by the same people at the same time; the process and technician certification requirements are expected to differ.

shredded, with the refrigerant in the foam collected from the gaseous and solid phases and subsequently destroyed.

4. Potential Emission Reductions

Estimated annual emission reductions of 0.9 $MMTCO_2E$ are currently possible for residential refrigerator and freezer foam recovery[4]. This number may be offset somewhat by CO_2 emissions associated with foam destruction[5]. Of the 0.9 $MMTCO_2E$, 0.8 $MMTCO_2E$ is due to recovery of foam containing R-11.

The CO_2E emission reductions are calculated for 2005 with only refrigerators and freezers considered since quantities of insulating foams recovered from A/Cs and building wastes annually in California are unknown. Without knowledge of the numbers and age distributions of appliances in California, 2020 emissions reductions based on sector growth and transitional blowing agent use estimates were not possible. However, it is reasonable to assume that approximately 0.9 $MMTCO_2E$ reductions will be possible every year until refrigerators and freezers containing R-11 are gone.

To summarize, by about 2012 annual emissions reductions of **0.9 $MMTCO_2E$** may be possible by recovering foams banked in old refrigerators and freezers that would otherwise go to landfills. Emissions benefits associated with foam recovery from building and additional C/D wastes could not be estimated.

5. Estimated Costs/Economic Impacts and the Impacted Sectors/Entities

The US EPA estimates that automated foam recovery at appliance EOL costs approximately **\$6.5/TCO_2E**, while manual foam recovery at appliance EOL costs approximately **\$48/TCO_2E**. The US EPA states that foam recovery from steel faced building panels is cost effective where large volumes of panels are in one place[6].

The impacted sectors and entities would mostly be appliance salvagers/recyclers and possibly individuals disposing of foam-containing appliances, as recovery costs are expected to be passed along to the user. Recovery of foam from buildings is not currently performed.

---

[4] The following assumptions were used: 1) 20 year lifetimes for refrigerators, 2) R-11 use in refrigerators stopped in 1995; from 1995 – 2005 HCFC-141b was used, 3) in 2005, half of disposed refrigerators contain R-11 as the foam blowing agent and the other half contain 141b, 4) 25% of the foam blowing agent is lost into the cabinet and is released into the atmosphere and that the remaining 75% is recoverable, 5) 13,000,000 refrigerator/freezers are disposed of annually in the US and 60% go to landfills or transfer stations 6) the California population fraction was roughly 13% in 2005, 7) 100-year direct GWPs of 4600 and 700 were used for R-11 and HCFC-141b, respectively, 8) blowing agent masses of 0.45 kg/appliance and 0.38 kg/appliance for R-11 and HCFC-141b, respectively, were obtained from USEPA (Dave Godwin, personal conversation, 2/07).

[5] An additional 0.8 MMT CO2E should be avoided at appliance EOL, as refrigerant recovery is mandated by federal and state law; this is discussed in the following strategy, ARB 4-2. Foam destruction would require a large amount of additional analysis; currently, USEPA is developing a plan to destroy ODSs at RCRA facilities, and the operating assumption is that the CO2 emissions associated with relatively small amounts of foams and refrigerants are small compared to the hazardous waste destruction throughput of a typical RCRA facility, but this supposition is subject to further analysis and change.

[6] USEPA, Draft Proposed Measures Arising from the IPCC/TEAP Special Report & its Supplement, by End-Use, Expert Workshop on IPCC/TEAP Special Report, July 2006.

A foam recovery program for appliances is currently operating as an incentive program between the US EPA and utility companies, some of which are located in California (Responsible Appliance Disposal program, or RAD, see following strategy, ARB 4-2). The program was started in 2006 and the success of the program has not been gauged yet, although it is anticipated that a mandatory program would be more effective.

6. Technical Feasibility

The technology required to remove foam blowing agents from appliances and other construction and demolition wastes is feasible, but labor intensive if manual removal is employed. Automated foam removal from appliances is technically feasible, and can be performed during scrap metal processing and recovery.

7. Additional Considerations

Ozone depleting substances (ODSs) were used in the past as foam-blowing agents; CFC-11 (100-year direct GWP of 4,600) was used for many years, and phaseout of its replacement, HCFC-141b (100-year direct GWP of 700), from appliance foam has only been occurring in the past four years. Recovering and destroying ODSs may be a cost-effective way to reduce high-GWP gas emissions, and also reduces negative impacts on stratospheric ozone.

It is also possible that special facilities will need to be constructed if automated foam removal is deemed more economically feasible than manual foam removal and would therefore need to be considered in any estimates of cost-effectiveness.

The impacted sectors and entities would mostly be appliance salvagers/recyclers and possibly individuals disposing of foam-containing appliances, as recovery costs are expected to be passed along to the user. California trade associations associated with recycling of scrap metals are unknown. Coordination with the US EPA with respect to this regulation is ongoing.

8. Division:	Research Division
Staff Lead:	Whitney Leeman
Section Manager:	Vacant
Branch Chief:	Richard Corey

9. References

Arthur D. Little, Inc., Global Comparative Analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire Protection Applications, Final Report to the Alliance for Responsible Atmospheric Policy, March 21, 2002.

David Godwin (USEPA), Marian Martin Van Pelt and Katrin Peterson (ICF Consulting), Modeling Emissions of High Global Warming Potential Gases from Ozone Depleting Substance Substitutes, 2003.

IPCC/TEAP, IPCC Special Report on Safeguarding the Ozone Layer and the Global Climate System, Issues related to Hydrofluorocarbons and Perfluorocarbons, 2005.

SEPA, Guidance on the Recovery and Disposal of Controlled Substances Contained in Refrigerators and Freezers, 2002: http://www.sepa.org.uk/pdf/consultation/closed/2003/fridge/fridge_consultation.pdf

USEPA, Draft Proposed Measures Arising from the IPCC/TEAP Special Report & its Supplement, by End-Use, Expert Workshop on IPCC/TEAP Special Report, July 2006.

USEPA, RAD program website: http://www.epa.gov/ozone/snap/emissions/radp.html

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C04*
ID NUMBER:	*ARB 2-6*
TITLE:	*GUIDANCE AND PROTOCOLS FOR LOCAL GOVERNMENTS TO FACILITATE GHG EMISSION REDUCTIONS*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 3nd quarter of 2008.

Local governments have the power to affect the main sources of pollution directly linked to climate change through infrastructure investments, land use decisions, building codes, and municipal service management. While a handful of local governments in California have already started to plan and implement local GHG reduction measures, development of a State guidance document and local government protocols is needed to encourage and support greater and coordinated local action statewide. Furthermore, development of these items will help ensure consistency and coordination between the multiple state agencies involved with implementing AB 32, with regard to supporting and advising Local Government actions for GHG reductions.

Staff recommend developing guidance documents for Local Governments that outline GHG reduction opportunities, as well as protocols for emission reduction accounting.

3. Early Action Description

The first step of this strategy will be to coordinate with the Climate Action Team, local governments, the California Climate Action Registry, and local government support organizations like ICLEI (Local Governments for Sustainability). The guidance document will address: 1) best practices for local governments to reduce GHG emissions; 2) categorization and prioritization of strategies by applicability to community types (i.e., urban, suburban, rural), cost-effectiveness, time needed to achieve reductions, etc.; 3) local government protocols for emission reduction accounting; and 4) appropriate modeling tools to support emission quantification at the local level.

Specific recommendations could include: implementing green building standards, stronger recycling programs, energy conservation, changing municipal fleets to cleaner alternatives (gas-electric hybrids, natural gas fueled vehicles, etc.), promoting sustainable communities and smart growth; encouraging LED street and traffic lights; promoting alternative energy (e.g. solar).

These are effective actions that local governments can implement to reduce carbon emissions, which not only help the environment but could be cost effective.
Guidance documents and protocols from this strategy will be voluntary not regulatory and will be developed in close coordination with stakeholders representing state, local, regional and industry perspectives. A strong long-term local level education program will be necessary for successful implementation.

Groups to work with include:

Trade Associations: California Building Industry Association (CBIA), League of California Cities, California State Association of Counties (CSAC), California Association of Councils of Governments (CALCOG).

Government Agencies: Governor's Office of Planning and Research, California Air Pollution Control Officers Association (CAPCOA), and Local Air Pollution Control Districts, local government agencies, Cal/EPA's Climate Action Team and its Land Use/Smart Growth Subgroup, Department of Community and Housing Development, Department of Transportation, California Energy Commission, Integrated Waste Management Board.

4. Potential Emission Reductions

Potential emission reduction impacts are difficult to predict with current knowledge.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Estimated costs and economic impacts are difficult to determine and this time.

6. Technical Feasibility

With regard to developing a best practices document for Local Government, many other cities, states, and private organizations have acknowledged the need to reduce global warming pollution and have taken steps to coordinate concerted efforts. Below is a list of just a few national and international programs that staff will consider closely:

- U.S. Mayors for Climate Protection - promote actions that city governments can do to profitably and reduce carbon emissions.
- The Clinton Climate Initiative - works with C40 Large Cities Climate Leadership Group, an association of large cities dedicated to tackling climate change—to develop and implement a range of actions that will accelerate greenhouse gas emissions reductions.
- ICLEI's Cities for Climate Protection™ (CCP) Campaign - assists cities to adopt policies and implement quantifiable measures to reduce local greenhouse gas emissions, improve air quality, and enhance urban livability and sustainability. More than 800 local governments participate in the CCP, integrating climate change mitigation into their decision-making processes.

As for protocols for emission reduction accounting, the California Climate Action Registry (CCAR) is currently under contract with the ARB to develop a suite of protocols for reporting and certifying GHG emission reductions for Local Governments. As part of this effort, CCAR will be preparing a scoping document that describes the full scope of local government activities and operations to which quantification protocols can be applied. Data and analysis from this work will support development of a Local Government guidance document.

7. Additional Considerations

Many of the actions that may be recommended fall under the jurisdiction of other state and local agencies therefore this strategy will provide advice and support action, rather than mandate.

An important aspect of this strategy will be verification of the emission reductions and the value associated with it. Future efforts will focus on how local governments can take credit for net reductions and best uses for those credits.

Proposed Board Hearing Date: July 2008

8. **Division:** Office of Climate Change
   Staff Lead: James Goldstene

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C05*
ID NUMBER:	*2-7*
TITLE:	*GUIDANCE/PROTOCOLS FOR BUSINESSES TO FACILITATE GHG EMISSION REDUCTIONS*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 2nd quarter of 2008.

Currently, California businesses' energy consumption contributes approximately 12 MMTCO2E GHG emissions per year. Through strategies such as efficient building practices, motor vehicle fleet changes, operational changes, fossil fuel switching, and recycling, local businesses can reduce cost effectively their carbon footprint. These emission reductions range from quite minor to very significant and all reductions will assist the State in meeting its targets under AB32.

Greenhouse gas emission reduction guidance and suggested strategies for local businesses will be presented to the Board in July 2008. At present, it is anticipated that implementation of local business reduction measures will be strongly encouraged, but strictly on a voluntary basis with a dedicated and aggressive educational outreach effort. It is also anticipated that initially, guidance will be broad and, hence applicable to a broad spectrum of businesses. In time, the guidance will evolved into focused, sector-specific recommendations. To the extent possible, a robust emission verification element will be integrated into the guidance so that reductions can be quantified.

3. Early Action Description

This strategy will provide guidance and informational resources to local businesses on best practices, emission calculation and verification methods, case studies, cost-effectiveness information, and other tools to assist in reducing greenhouse gas emissions. The guidance will seek to distill and translate the vast amount of information already existing into tangible and concrete steps that local business can implement. Staff's efforts will be focused on reaching out to small/mid-size businesses to engage them in the development of actions, to offer guidance for estimating emissions, identifying and quantifying reductions, and facilitating actions to reduce carbon footprints. Information on relevant options, particularly those that have been implemented successfully by others at a local or national level will be highlighted.

This strategy will focus on businesses ranging from a small office to mid-size corporations and will address the climate benefits of both operational and behavioral changes. Operational changes could include the use of *Energy Star* equipment, compact fluorescent light bulbs, water conservation, recycling, and motor vehicle fleet changes. In addition to physical changes to the operation of the business (e.g., new construction, retrofits to existing buildings), the guidance will address the benefits of behavioral changes such as incentives for carpooling/walking/bicycling to the workplace, facilitate employees walking to lunch, procuring "green" products, incentives for reducing waste/electricity consumption, Governor's Awards program to recognize green business leaders, etc. Businesses that choose to pledge to participate in the effort for climate protection will be encouraged and assisted to inventory and report their emissions via recognized channels such as the California Climate Action Registry.

To be successful, this strategy must convince businesses to embrace new projects and initiatives from both environmental and economic perspectives. Thus, a key element of success in the strategy will be to determine how enhancements of operational efficiencies can result in increased profits for a participating business via savings in energy consumption. In addition to working with established organizations that represent or have strong ties with the targeted audience (small and medium business owners/managers), emphasis will be placed on implementation through a variety of means (e.g., information in association newsletters, presentations at trade meeting, web-based tools, etc.). ARB staff will monitor the effectiveness of and response to efforts in order and make necessary adjustments as needed to strengthen the program into the future.

4. Potential Emission Reductions

Energy efficiency measures associated with green buildings address lighting, heating and cooling, water conservation, refrigeration, and recycling and often lead to a large decrease in GHG emissions. The US Department of Energy states that new energy-efficient design can cut energy usage by 50%; renovation of existing buildings can yield savings of up to 30%. Governor Schwarzenegger signed Executive Order S-20-04 in 2004, which sets a goal of reducing energy use in State-owned buildings 20% by 2015 (from a 2003 baseline). The private commercial sector is encouraged to do the same. The California Energy Commission estimated 2004 GHG emissions in the commercial sector to be approximately 12 MMTCO2E. Thus, achieving a 20% reduction in GHG emissions as called for in the Executive Order could potentially realize a reduction of more than 2 MMTCO2E in the commercial sector.

5. Estimated Costs / Economic Impacts and the Impacted Sectors/ Entities

Cost information will vary widely depending on the specific action implemented by a local business. Thus, it is premature to report this information at this time. However, information coming from existing examples that have successfully achieved improvements indicates that the return on investment for energy efficiency measures is often recovered in three to five years, resulting in long term cost savings due to lower utility bills. Measures that could be implemented pursuant to this proposed early action are quite varied and potentially include installation of LED exit signs, efficient refrigeration systems, improved building insulation, purchase of *Energy Star* appliances and office equipment, and implementation of recycling programs. Improvements that are scaleable to square footage of operations will be pursued so that the emission reduction benefits can be pursued across all sizes of businesses.

6. Technical Feasibility

The proposed strategy benefits from the successful experience from several local businesses and other entities that have already set targets and developed climate action plans. The mitigation strategies will likely be a suite of best practices already in use and proven to be feasible and effective. Staff will work with the business community to ensure that this strategy focuses on activities and provide information that will promote real, quantifiable, and sustainable reductions. We will also focus on the most effective ways to target the information at decision makers. Hurdles may include developing and implementing guidance that is sufficiently specific and documented.

7. Additional Considerations

ARB will work in consultation with several agencies including: 1) California Energy Commission, 2) Business Associations 3) California Climate Action Registry 4) California Chamber of Commerce, 5) Utility providers, as well as many others.

8. Division:

Division:	Research Division/Planning and Technical Support Division/Office of Climate Change
Staff Lead:	TBD
Section Manager:	Annmarie Mora
Branch Chief:	Alberto Ayala

9. References:

California Energy Commission, Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004, October 2006.

U.S. Department of Energy, Energy Efficiency and Renewable Energy, Building Technologies Program, http://www.eere.energy.gov/buildings/info/office/index.html, January 27, 2006.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C06*
ID NUMBER:	*ARB 2-8*
TITLE:	*REDUCE SULFUR HEXAFLUORIDE (SF_6) FROM ELECTRICAL GENERATION*
PROPONENT:	*AIR RESOURCES BOARD STAFF*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 2nd quarter of 2011.

3. Early Action Description

This strategy proposes that the ARB develop a measure to reduce sulfur hexafluoride (SF_6) emissions from the electric power industry, which is the primary user of SF_6. SF_6 is a synthetic gas used as an insulating medium. The most common use for SF_6 is as an electrical insulator in high-voltage equipment that transmits and distributes electricity. Since the 1950's, the U.S. electric power industry has used SF_6 widely in circuit breakers, gas-insulated substations, and other switchgear used in the transmission system to manage the high voltages carried between generation stations and customer load centers. Fugitive emissions of SF_6 can escape from gas-insulated substations and switchgear through seals. It can also be released during equipment installation and when equipment is opened for servicing. Several factors affect SF_6 emissions from electric power systems, such as the type and age of the equipment (e.g., older circuit breakers can contain up to 2,000 pounds of SF_6, while modern breakers usually contain less than 100 pounds), and the handling and maintenance procedures practiced by the utilities.

SF_6 is a highly potent greenhouse gas. Over a 100-year period, SF_6 is 23,900 times more effective at trapping infrared radiation than an equivalent amount of carbon dioxide. SF_6 is also a very stable chemical, with an atmospheric lifetime of 3,200 years. Consequently, it will accumulate in the atmosphere.

The U.S. Environmental Protection Agency (U.S. EPA) reports that the most promising and cost-effective options to reduce SF_6 emissions are leak detection and repair, use of recycling equipment, and employee education and training.

4. Potential Emission Reductions

U.S. EPA estimates that the SF_6 emissions from electric power systems in the U.S. in 2005 were 4.9 million metric tons of CO_2-equivalent (MMTCO2E). The Cal/EPA Climate Action Team

Report states that hydrofluorocarbons, perfluorocarbons, and SF_6 accounted for about 3.5 percent of gross 2002 greenhouse gas emissions in California (CO_2-equivalent). USEPA reports that use of recycling equipment can reduce SF_6 emissions by about 10 percent, and leak detection and repair can reduce SF_6 emissions by 20 percent.

Further investigation is required to determine the portion of SF_6 emissions attributed to the California electric power industry and the most appropriate and effective emission reduction equipment and practices. Therefore, ARB staff cannot yet determine the total emission reduction potential of this strategy.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

U.S. EPA reports that cost-effective operational improvements and equipment upgrades can be accomplished at an average cost of $9.00 per pound. The cost impacts of this strategy specific to the California power sector cannot be determined at this time as further investigation is required. ARB staff assumes that costs will be borne by the power companies and could translate into increased electricity rates for consumers.

6. Technical Feasibility

The most cost-effective SF_6 emission reduction options reported by USEPA focus on maintenance and education, and therefore do not appear to have any associated major technical issues. However, to the extent that repair and replacement activities are used to reduce emissions, scheduling to minimize electrical system disruption could be an issue.

7. Additional Considerations

8. Division: Stationary Source Division

Staff Lead: Chris Gallenstein
Section Manager: Mike Waugh
Branch Chief: Mike Tollstrup

9. References:

[1] *California Environmental Protection Agency, "Climate Action Team Report to Governor Schwarzenegger and the Legislature," March 2006.*

[2] *U.S. Environmental Protection Agency, "SF6 Emission Reduction Partnership for Electric Power Systems," April 17, 2007: http://www.epa.gov/electricpower-sf6/index.html*

[3] *U.S. Environmental Protection Agency, "SF6 Emission Reduction Partnership for the Magnesium Industry," November 28, 2006: http://www.epa.gov/highgwp/magnesium-sf6/faq.html*

[4] *U.S. Environmental Protection Agency, "U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions," publication #EPA-000-F-97-000, June 2001.*

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C07*
ID NUMBER:	*ARB 2-10*
TITLE:	*ALTERNATIVE SUPPRESSANTS IN FIRE PROTECTION SYSTEMS*
PROPONENT:	*STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 4^{th} quarter of 2011.

Staff recommends developing a proposal for the use of lower GWP substances in fire protection systems to the extent that safe, technically feasible, and cost-effective alternatives are available. These systems, called total flooding systems, are typically used to protect large computer data management areas in commercial buildings, clean room manufacturing facilities, telecommunications equipment, museums and archives. If further evaluation supports the use of this measure as a early action, the proposal will be considered by the Board by December 2011**.**

One possible approach (for illustrative purposes only): By 2012, require that all new total flooding fire suppressant systems use fire suppressants with a GWP below a specified threshold. The analysis may also explore requiring, providing the options are technologically feasible and cost-effective, that existing total flooding fire suppressant systems enhance inspections of or replace systems using substances with a GWP above a specified threshold, which may or may not be different than the above-mentioned threshold.

3. Early Action Description

Use lower global warming potential (GWP) gases in new fire protection systems to the extent that safe, technically feasible, and cost-effective alternatives are available.

4. Potential Emission Reductions

Statewide Emission Inventory[1]
2005 GHG Emission Inventory: 0.05 $MTCO_2$
2020 Projected GHG Emissions: 0.23 $MTCO_2$
Anticipated 2020 Reductions: <0.1 MMT CO_2E which assumes 43 percent control

[1] All emissions estimates based on USEPA Vintaging Model scaled to California based on population assuming only HFC 227 since HFC 23 is only 1%, Halon emission data are not available at this time. Reduction estimates based on technical feasibility from EPA 2006 for new systems. Including reductions from replacement of systems with Halons or HFCs would increase the reduction potential.

Prior to the 1990s, most total flooding fire suppression systems used Halon 1301, however, it is an ozone depleting substance and, based on the Montreal Protocol on Substances that Deplete the Ozone Layer, its production in the US was completely phased out by the mid-1990s. Due to this fact, new systems have moved to Halon replacements, however, with the exception of the US Department of Defense, there has been no concerted effort to remove existing Halon 1301 systems and recycled Halon 1301 is inexpensive and widely available for recharge needs (Wickham 2002). The lifetime of a system ranges from 10 to 35 years.

There are several Halon alternatives being used in fire suppression systems. The US EPA estimates that HFC 227ea covers approximately 16 percent of the total new flooding fire protection systems with HFC 23 (<1%), inert gas (10%) and not-in-kind alternatives (NIK) such as powdered aerosols, water sprinklers and mist systems making up the remainder of the market (74%) (US EPA, 2006). Although these Halon alternatives are not ozone depletors, HFC 227ea and HFC 23 do have significant global warming potentials (GWP) of 2990 for HFC 227ea and 11700 for HFC 23 (IPCC, 1996). In comparison, Halon 1301 has a GWP of 7030, much higher than the common alternative of HFC 227ea (WMO, 2002).

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

The US EPA estimates that the least cost alternative would be approximately $40/tonne CO_2E (US EPA, 2006) in the US for new systems. The estimate reflects the relative cost of alternative formulations, space costs, and costs associated with installing a new, and sometimes weightier, type of system. The costs may need to be updated and revised to reflect the situation in California. For example labor costs and heating and cooling costs differ from the average for the US. This analysis did not consider costs for replacement systems.

Total flooding systems are used by a wide variety of sectors with uses varying from data processing centers to the oil and gas industry to military weapons systems. Any requirements effecting new systems will be fairly evenly distributed among the sectors. Systems with low expected lifetimes (10-15 years) will be impacted most in the short-term as systems need to be replaced sooner. Any requirements to replace existing systems may have a larger impact on sectors with systems that have long expected lifetimes (35 years). These sectors were expecting the system to last up to 35 years but may have to upgrade the system much sooner.

6. Technical Feasibility

There are a number of low GWP alternatives to Halons and HFCs for use in total flooding fire suppression systems, however, they need to be analyzed for effectiveness, space constraints, safety concerns, and other issues. Not every alternative will work in every situation and technical feasibility will be vary based on space needs, human exposure potential for asphyxiates, and other constraints.

7. Additional Considerations

Some factors that need to be considered as part of the evaluation include whether the alternatives are as effective, do the alternatives have increased toxicity, are there any multi-media environmental impacts and whether the strategy would this apply to only new installations or would existing installations need to be retrofitted? Other questions that need to be considered include what happens to the HFCs and Halons from any systems that are phased out, and will other agencies and insurance companies allow their use? Another fundamental question concerns whether another agency would be more appropriate to adopt the strategy as well as determining if a voluntary measure be just as effective?

Affected Entities: Commercial building owners and property management companies, fire suppressant manufacturers (e.g., 3M, Great Lakes Chemical, Brownell, Dupont, Stat-X) and system manufacturers/suppliers (Sea fire, Nautical, Many suppliers – CA based include CalProtection, Chemetron, Diversified Protection, Facilities Protection Inc., Intelligent Technologies and Systems, and RFI Communications & Security).

Trade Associations: Building Industry Association, Chemical Manufacturers Association, Building Insurance, Fire Suppression Systems Association, Fire Equipment Manufacturers Association and others.

Government Agencies to coordinate with: California Department of Fire Protection, State Fire Marshall's Office, Department of General Services, OEHHA, DHS, Cal-OSHA, and others.

Proposed Board Hearing Date: December 2011

8. **Division:** Research Division
   Staff Lead: Elizabeth Scheehle
   Section Manager: Mike FitzGibbon
   Branch Chief: TBD
   Staff Attorney: TBD

9. **References:**

Intergovernmental Panel on Climate Change (IPCC). 1996. Climate Change 1995: The Science of Climate Change. J.T. Houghton, L.G. Miera Filho, B.A. Callander, N. Harris, A. Katternberg, and K. Maskell (eds.). Cambridge, UK: Cambridge University Press.

USEPA, 2006. Global Mitigation of Non-CO_2 Greenhouse Gases, EPA Report 430-R-06-005. Available at: http://www.epa.gov/nonco2/econinv/downloads/GlobalMitigationFullReport.pdf

Wickham, Robert. 2002. Status of Industry Efforts to Replace Halon Fire Extinguishing Agents. Wickham and Associates. March 16. Available at: http://www.epa.gov/ozone/snap/fire/status.pdf.

World Meteorological Association (WMO). 2002. Scientific Assessment of Ozone Depletion: 2002. Global Ozone Research and Monitoring Project - Report No. 47, 498pp., Geneva, 2003.

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C08*
ID NUMBER:	*ARB 2-11*
TITLE:	*FORESTRY PROTOCOL ENDORSEMENT*
PROPONENT:	*STAKEHOLDER SUGGESTION*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in the 4th quarter of 2007.

Staff recommends this strategy remain on the list as an early action by Board endorsement of the California Climate Action Registry (CCAR) forestry protocols for immediate use to enhance voluntary greenhouse gas emissions reductions. Staff recommends a two-phase process that allows early action by bringing existing sector, project, and certification protocols, developed by CCAR, to the Board for approval in October 2007 and also allows for longer term consideration and review of additional forestry protocol development as determined in the initial public workshop process. Endorsement of sector and project forest protocols would be non-regulatory, because their use would be voluntary.

3. Early Action Description

Forestry is the only sector that *actively removes* greenhouse gases from the atmosphere. The CCAR forestry protocols represent the work of leading experts in the field of forestry and in protocol development, the input of stakeholders and the public over a 4-year public process, and the review by 50 external experts, representing the forest industry, policy and academia. The protocols have been approved by the Board of Forestry (2004) and the CCAR Board (2005). The three protocols together – the sector, project, and certification protocols – are a cohesive and comprehensive set of methodologies for forest carbon accounting, and contain the elements necessary to generate high quality, conservative carbon credits. The first step to effective carbon reduction is accurate carbon accounting.

Unlike other sectors, immediate action in the forest sector does not result in instantaneous greenhouse gas reduction, because forests need time to grow to realize reduction benefits. Therefore, the sooner these voluntary protocols are endorsed, the faster forest projects can be put in place, to establish *future* reductions. The three carbon reduction project types – reforestation, conservation forest management, and avoided development – provide an accounting framework for maximizing carbon sequestration and minimizing carbon loss without compromising the other ecosystem functions forest provide (habitat, structure, nutrient cycling), as well as the suite of other benefits humans depend on from the forests (water storage, soil stability, temperature modification, air and water purification, wood products, recreation). As such, they are ready for use in voluntary measures to reduce carbon emissions in California.

4. Potential Emission Reductions

Because they are critical to accurate carbon accounting, the forestry protocols are required in several of the forest-related Climate Action Team (CAT) strategy implementation plans. A third of carbon reductions through the forest CAT plan depend on application of these forest protocols which equates to a cumulative sequestration of roughly 10 $MMTCO_2eq$ between now and 2020. The CAT-strategy reforestation projects in the year 2020 are expected to result in GHG emissions reduction of 2 MMTCO2eq (CAT, 2007). While there is already interest in the protocols from the private forest sector, the potential emissions reduction from the voluntary use of the protocols could vary depending on a variety of factors, including management activity, site fertility, and available funding. One unpublished industry study suggests a potential increase of 2¼-fold in the pine zone (Steve Brink, California Forestry Association, pers. comm.). Nationally, an additional 100 to 200 Tg C/yr of forest carbon sequestration is achievable, but would require investment in inventory and monitoring, development of technology and practices, and assistance for land managers (Birdsey et al. 2006).

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Currently, the methodologies for carbon stock assessment require intensive sampling programs to meet the required confidence levels for verification. This is labor and time intensive, and therefore costly. There is currently no better technology/methodology to measure carbon if a high degree of certainty is required in carbon stock assessment. Carbon stock certainty should meet the criteria of other carbon emission estimates in the state (20% of the mean estimate). Smaller landowners may find the cost to implement the sampling and subsequent verification too burdensome to participate. The larger industrial landowners (>30,000 acres) should be able to use forest stocking data from sustained-yield management plans which they are required to submit to California Department of Fire and Forest Protection (CalFire). Data for inventorying large land areas may be accessible from CalFire plot data and USFS Forest Inventory and Analysis plot data.

6. Technical Feasibility

The carbon accounting techniques used in the forest protocols are standard forest measurement techniques.

7. Additional Considerations

The forestry protocols are designed for small to mid-sized private forest ownerships. There is a need for continued development of forest accounting methodologies to address outstanding issues for: 1) public forest ownerships and for 2) industrial forest private land ownerships. These issues can be addressed within the framework of the existing protocols by defining additional project types beyond the three project types (reforestation, conservation forest management, and avoided deforestation) in the current protocols. For public landowners, issues to resolve include legality of permanent easement transfer, baseline/additionality definition, and carbon offset ownership. By recognizing the need for additional project types in the future, the existing forestry protocols can be moved forward through the public process, endorsed and implementation immediately while the new project types are developed through a longer term public process. This will expedite the availability of the forest protocols for immediate use, while still allowing due consideration to the different needs of the industrial and public forest sector.

Affected Entities: Any forest ownership in California could participate in all forest project types, including state and federal public forests, and private forests. Many non-forest entities might participate in reforestation activities, including local governments, utilities, others.

Trade Associations: California Forestry Association.

Government Agencies Coordination: California Department of Forest and Fire Protection, Board of Forestry, United States Forest Service.

8. **Division:** Planning and Technical Support Division
   Staff Lead: Jeanne Panek
   Section Manager: Dale Shimp
   Branch Chief: Richard Bode

9. **References:**

The protocols can be found in their entirety on the California Climate Action Registry website at: http://www.climateregistry.org/PROTOCOLS/FP/

Birdsey, R., K. Pregitzer, and A. Lucier. 2007. Forest Carbon Management in the United States: 1600–2100. J. Environ. Qual. 35:1461–1469.

CAT, Climate Action Team. 2007. Climate Action Team proposed early actions to mitigate climate change in California. Draft for public review. April 2007. www.climatechange.ca.gov/climate_action_team/reports/2007-04-20_CAT_REPORT.PDF

Staff Analysis of Proposed Early Action for Climate Change Mitigation in California

1. Early Actions Strategy Name and Proponent

SUMMARY #	*C09*
ID NUMBER:	*ARB 2-18 / EJAC-2*
TITLE:	*ENFORCEMENT OF FEDERAL BAN ON HFC RELEASE DURING SERVICE/DISMANTLING OF MVACS*
PROPONENT:	*2006 CAT REPORT*

2. Staff Recommendation

This measure was approved by the Board as an early action at its June 2007 hearing. Based on further evaluation by staff, no change in the classification of this measure is recommended. The Board date for consideration of this item is anticipated in 2nd quarter of 2010.

This non-regulatory strategy is expected to be developed in close collaboration with the United States Environmental Protection Agency (US EPA). The strategy is not a stand-alone measure. Rather, it is designed to be implemented in concert with a number of other strategies that staff has identified for mitigating the climate impact of HFCs.

3. Early Action Description

The goal of this non-regulatory strategy is improved compliance with a regulation of US EPA (40 CFR 82.154) that prohibits the venting of certain types of refrigerant, including HFCs, to the atmosphere when MVACS equipment is serviced or dismantled. Venting is avoided by recovering refrigerants with specialized equipment. The recovered refrigerant can be re-used by the owner or transferred to re-processors approved by US EPA.

The main focus of the proposed strategy would be the climate impact abatement of HFCs used in the air-conditioning (A/C) systems of vehicles that are to be dismantled. The current degree of compliance with 40 CFR 82.154 is poorly documented but under review. Per this strategy, better compliance by dismantlers would be obtained via a cooperative program that would be created among ARB's Enforcement Division, appropriate offices in the US EPA, and the environmental protection offices of the counties where dismantling activity is taking place. The specific form of the program has not been determined yet, pending quantification of the avoidable emissions of HFCs. However, the anticipated approach would emphasize enhanced enforcement of existing federal requirements for recovery via audits of activities and documentation.

4. Potential Emission Reductions

Potential emission reductions from dismantling have been estimated to be in the range of 0.1 to 0.6 MMTCO2E in 2010 and 0.1 MMTCO2E in 2020. The potential reductions are lower in the year 2020 because it is assumed that half of the cars going to the dismantlers will have new low-GWP refrigerant in the A/C system instead of HFC-134a as called for in other companion

HFC reduction strategies. Preliminary estimates suggest that the refrigerant bank in EOL vehicles could be as high as 0.5 $MMTCO_2E$ per year. Estimates of annual A/C servicing emissions ranges from 0.3 to 0.6 $MMTCO_2E$. The ARB staff has initiated extramural research to estimate the annual amount of HFC that is available for recovery from vehicle at end-of-life and we will continue to work with the USEPA to develop improved estimates of the portion of the available amount that is being recovered and other parameters.

5. Estimated Costs / Economic Impacts and the Impacted Sectors / Entities

Some dismantlers may not have the latest compliant hardware for recovering refrigerants or any equipment at all. Each such dismantler who would be prompted to purchase the equipment would have to spend in the neighborhood of $3000 to $4000 per unit. The number of units needed would depend on the size of the operation (vehicle throughput). However, this would be an expense that the dismantler has so far avoided only through failure to comply with the existing federal regulation. Thus, this is not a cost burden associated with the proposed strategy.

The same statements apply to obtaining certification for technicians who use the recovery equipment, but with minimal anticipated costs. Training for the US EPA's certification program is offered by various commercial schools. In addition, the Mobile Air Conditioning Society offers free training (a downloadable pamphlet) and a nominal exam fee, so the necessary expense for operator certification should be minimal.

6. Technical Feasibility

This measure is technically feasible because it is the current federal law, which has been in existence for some time. As such, the equipment exists to recover the refrigerant from automobile A/C systems whether they are being serviced or dismantled. The rigorous enforcement of the federal regulation in California is meant to force vehicle dismantlers to universally use refrigerant-recovery equipment as required by law. The same is true for garages and auto service centers that service MVACS; however, the fraction of such shops that do not have the requisite equipment may be small. It should be noted that recovery procedures and equipment are being revised by industry standard setting bodies to make the process more effective with a higher recovery rates of the refrigerant.

7. Additional Considerations

This strategy involves the enforcement of an existing federal regulation (U.S. EPA- 40 CFR 82.154) that prohibits the venting of refrigerants to the atmosphere when the MVACS is being serviced or dismantled. Some local air districts adopt the federal regulation by reference and others have their own regulation which prohibits the release of refrigerants into the atmosphere. Originally, this item was a strategy in the Climate Action Team Report of March 2006 that ARB intends to pursue as one of suite of measures designed for reducing HFC refrigerant impacts. This strategy involves the creation of a cooperative program among ARB's Enforcement Division, appropriate offices in the U.S. EPA, and local air districts in California. U.S. EPA is currently working on a regulatory impacts assessment that will estimate the emission reductions and costs associated with this type of measure. That work and other on-going activities are expected to yield the necessary additional information for strategy development such as the number of non-compliant dismantlers and shops that perform MVACS servicing in California.

8. Division: Research Division
Staff Lead: Winston Potts
Section Manager: Tao Huai
Branch Chief: Alberto Ayala

9. References:

[1]Vincent, R., "*HFC Reduction Strategy 2-2-5, Enforcement of the Federal Ban on Releasing HFCs During Servicing and Dismantling of MVACS," California Air Resources Board, 2006. As presented in the Climate Action Team Report of March 2006.*

[2]*Air Resources Board, HFC-134a as an Automotive Refrigerant - Background, Emissions and Effects of Potential Controls, August 6, 2004 (www.arb.ca.gov/cc/cc.htm)*

[3] *Karen Thundiyil, USEPA, personal communication, 7/26/07.*

[4] *Improved Mobile Air Conditioning Program (IMAC), "Reducing Refrigerant Emissions at Service and Vehicle End of Life," June 30, 2007*







Climate Change Scoping Plan

a framework for change

DECEMBER 2008

Pursuant to AB 32
The California Global Warming Solutions Act of 2006

Prepared by
the California Air Resources Board
for the State of California

Arnold Schwarzenegger
Governor

Linda S. Adams
Secretary, California Environmental Protection Agency

Mary D. Nichols
Chairman, Air Resources Board

James N. Goldstene
Executive Officer, Air Resources Board

Table of Contents

APPENDICES

This page intentionally blank

EXECUTIVE SUMMARY

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006). The event marked a watershed moment in California's history. By requiring in law a reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020, California set the stage for its transition to a sustainable, clean energy future. This historic step also helped put climate change on the national agenda, and has spurred action by many other states.

The California Air Resources Board (ARB or Board) is the lead agency for implementing AB 32, which set the major milestones for establishing the program. ARB met the first milestones in 2007: developing a list of discrete early actions to begin reducing greenhouse gas emissions, assembling an inventory of historic emissions, establishing greenhouse gas emission reporting requirements, and setting the 2020 emissions limit.

ARB must develop a Scoping Plan outlining the State's strategy to achieve the 2020 greenhouse gas emissions limit. This Scoping Plan, developed by ARB in coordination with the Climate Action Team (CAT), proposes a comprehensive set of actions designed to reduce overall greenhouse gas emissions in California, improve our environment, reduce our dependence on oil, diversify our energy sources, save energy, create new jobs, and enhance public health.

This "Approved Scoping Plan" was adopted by the Board at its December 11, 2008 meeting. The measures in this Scoping Plan will be developed over the next two years and be in place by 2012.

Reduction Goals

This plan calls for an ambitious but achievable reduction in California's carbon footprint. Reducing greenhouse gas emissions to 1990 levels means cutting approximately 30 percent from business-as-usual emission levels projected for 2020, or about 15 percent from today's levels. On a per-capita basis, that means reducing our annual emissions of 14 tons of carbon dioxide equivalent for every man, woman and child in California down to about 10 tons per person by 2020. This challenge also presents a magnificent opportunity to transform California's economy into one that runs on clean and sustainable technologies, so that all Californians are able to enjoy their rights in the future to clean air, clean water, and a healthy and safe environment.

Significant progress can be made toward the 2020 goal relying on existing technologies and improving the efficiency of energy use. A number of solutions are "off the shelf," and many – especially investments in energy conservation and efficiency – have proven economic benefits. Other solutions involve improving our state's infrastructure, transitioning to cleaner and more secure sources of energy, and adopting 21st century land use planning and development practices.

A Clean Energy Future

Getting to the 2020 goal is not the end of the State's effort. According to climate scientists, California and the rest of the developed world will have to cut emissions by 80 percent from today's levels to stabilize the amount of carbon dioxide in the atmosphere and prevent the most severe effects of global climate change. This long range goal is reflected in California Executive Order S-3-05 that requires an 80 percent reduction of greenhouse gases from 1990 levels by 2050.

Reducing our greenhouse gas emissions by 80 percent will require California to develop new technologies that dramatically reduce dependence on fossil fuels, and shift into a landscape of new ideas, clean energy, and green technology. The measures and approaches in this plan are designed to accelerate this necessary transition, promote the rapid development of a cleaner, low carbon economy, create vibrant livable communities, and improve the ways we travel and move goods throughout the state. This transition will require close coordination of California's climate change and energy policies, and represents a concerted and deliberate shift away from fossil fuels toward a more secure and sustainable future. This is the firm commitment that California is making to the world, to its children and to future generations.

Making the transition to a clean energy future brings with it great opportunities. With these opportunities, however, also come challenges. As the State moves ahead with the development and implementation of policies to spur this transition, it will be necessary to ensure that they are crafted to not just cut greenhouse gas emissions and move toward cleaner energy sources, but also to ensure that the economic and employment benefits that will accompany the transition are realized in California. This means that particular attention must be paid to fostering an economic environment that promotes and rewards California-based investment and development of new technologies and that adequate resources are devoted to building and maintaining a California-based workforce equipped to help make the transition.

A Public Process

Addressing climate change presents California with a challenge of unprecedented scale and scope. Success will require the support of Californians up and down the state. At every step of the way, we have endeavored to engage the public in the development of this plan and our efforts to turn the tide in the fight against global warming.

In preparing the Draft Scoping Plan, ARB and CAT subgroups held dozens of workshops, workgroups, and meetings on specific technical issues and policy measures. Since the release of the draft plan in late June, we have continued our extensive outreach with workshops and webcasts throughout the state. Hundreds of Californians showed up to share their thoughts about the draft plan, and gave us their suggestions for improving it. We've received thousands of postcards, form letters, emails, and over 1,000 unique comments posted to our website or sent by mail. All told, more than 42,000 people commented on the draft Plan.

ARB catalogued and publicly posted all the comments we received. In many instances, we engaged experts and staff at our partner agencies for additional evaluation of comments and suggestions.

This plan reflects the input of Californians at every level. Our partners at other State agencies, in the legislature, and at the local government level have provided key input. We've met with members of community groups to address environmental justice issues, with representatives of California's labor force to ensure that good jobs accompany our transition to a clean energy future, and with representatives of California's small businesses to ensure that this vital part of our state's economic engine flourishes under this plan. We've heeded the advice of public health and environmental experts throughout the state to design the plan so that it provides valuable co-benefits in addition to cutting greenhouse gases. We've also worked with representatives from many of California's leading businesses and industries to craft a plan that works in tandem with the State's efforts to continue strong economic growth.

In short, we've heard from virtually every sector of California's society and economy, reflecting the fact that the plan will touch the life of almost every Californian in some way.

Scoping Plan Recommendations

The recommendations in this plan were shaped by input and advice from ARB's partners on the Climate Action Team, as well as the Environmental Justice Advisory Committee (EJAC), the Economic and Technology Advancement Advisory Committee (ETAAC), and the Market Advisory Committee (MAC). Like the Draft Scoping Plan, the strength of this plan lies in the comprehensive array of emission reduction approaches and tools that it recommends.

Key elements of California's recommendations for reducing its greenhouse gas emissions to 1990 levels by 2020 include:

- **Expanding and strengthening existing energy efficiency programs as well as building and appliance standards;**
- **Achieving a statewide renewables energy mix of 33 percent;**
- **Developing a California cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system;**
- **Establishing targets for transportation-related greenhouse gas emissions for regions throughout California, and pursuing policies and incentives to achieve those targets;**

- **Adopting and implementing measures pursuant to existing State laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard; and**
- **Creating targeted fees, including a public goods charge on water use, fees on high global warming potential gases, and a fee to fund the administrative costs of the State's long term commitment to AB 32 implementation.**

After Board approval of this plan, the measures in it will be developed and adopted through the normal rulemaking process, with public input.

Key Changes

This plan is built upon the same comprehensive approach to achieving reductions as the draft plan. However, as a result of the extensive public comment we received, this plan includes a number of general and measure-specific changes. The key changes and additions follow.

Additional Reports and Supplements

1. Economic and Public Health Evaluations: This plan incorporates an evaluation of the economic and public health benefits of the recommended measures. These analyses follow the same methodology used to evaluate the Draft Scoping Plan.[1]

2. CEQA Evaluation: This plan includes an evaluation of the potential environmental impacts of the Scoping Plan under the California Environmental Quality Act (CEQA).[2]

Programmatic Changes

1. Margin of Safety for Uncapped Sectors: The plan provides a 'margin of safety,' that is, additional reductions beyond those in the draft plan to account for measures in uncapped sectors that do not, or may not, achieve the estimated reduction of greenhouse gas emissions in this plan. Along with the certainty provided by the cap, this will ensure that the 2020 target is met.

2. Focus on Labor: The plan includes a discussion of issues directly related to California's labor interests and working families, including workforce development and career technical education. This additional element reflects ARB's existing activities and expanded efforts by State agencies, such as the Employment Development Department, to ensure that California will have a green technology workforce to address the challenges and opportunities presented by the transition to a clean energy future.

---

[1] Staff will provide an update to the Board to respond to comments received on these analyses.

[2] This evaluation is contained in Appendix J.

3. Long Term Trajectory: The plan includes an assessment of how well the recommended measures put California on the long-term reduction trajectory needed to do our part to stabilize the global climate.

4. Carbon Sequestration: The plan describes California's role in the West Coast Regional Carbon Sequestration Partnership (WESTCARB), a public-private collaboration to characterize regional carbon capture and sequestration opportunities. In addition, the plan expresses support for near-term development of sequestration technology. This plan also acknowledges the important role of terrestrial sequestration in our forests, rangelands, wetlands, and other land resources.

5. Cap-and-Trade Program: The plan provides additional detail on the proposed cap-and-trade program including a discussion regarding auction of allowances, a discussion of the proposed role for offsets, the role of voluntary renewable power purchases, and additional detail on the mechanisms to be developed to encourage voluntary early action.

6. Implementation: The plan provides additional detail on implementation, tracking and enforcement of the recommended actions, including the important role of local air districts.

Changes to Specific Measures and Programs

1. Regional Targets: ARB re-evaluated the potential benefits from regional targets for transportation-related greenhouse gases in consultation with regional planning organizations and researchers at U.C. Berkeley. Based on this information, ARB increased the anticipated reduction of greenhouse gas emissions for Regional Transportation-Related Greenhouse Gas Targets from 2 to 5 million metric tons of CO_2 equivalent ($MMTCO_2E$).

2. Local Government Targets: In recognition of the critical role local governments will play in the successful implementation of AB 32, ARB added a section describing this role. In addition, ARB recommended a greenhouse gas reduction goal for local governments of 15 percent below today's levels by 2020 to ensure that their municipal and community-wide emissions match the State's reduction target.

3. Additional Industrial Source Measures: ARB added four additional measures to address emissions from industrial sources. These proposed measures would regulate fugitive emissions from oil and gas recovery and transmission activities, reduce refinery flaring, and require control of methane leaks at refineries. We

anticipate that these measures will provide 1.5 $MMTCO_2E$ of greenhouse gas reductions.

4. Recycling and Waste Re-Assessment: In consultation with the California Integrated Waste Management Board, ARB re-assessed potential measures in the Recycling and Waste sector. As a result of this review, ARB increased the anticipated reduction of greenhouse gas emissions from the Recycling and Waste Sector from 1 to 10 $MMTCO_2E$, incorporating measures to move toward high recycling and zero-waste.[3]

5. Green Building Sector: This plan includes additional technical evaluations demonstrating that green building systems have the potential to reduce approximately 26 $MMTCO_2E$ of greenhouse gases. These tools will be helpful in reducing the carbon footprint for new and existing buildings. However, most of these greenhouse gas emissions reductions will already be counted in the Electricity, Commercial/Residential Energy, Water or Waste sectors and are not separately counted toward the AB 32 goal in this plan.

6. High Global Warming Potential (GWP) Mitigation Fee: Currently many of the chemicals with very high Global Warming Potential (GWP)—typically older refrigerants and constituents of some foam insulation products—are relatively inexpensive to purchase. ARB includes in this plan a Mitigation Fee measure to better reflect their impact on the climate. The fee is anticipated to promote the development of alternatives to these chemicals, and improve recycling and removal of these substances when older units containing them are dismantled.

7. Modified Vehicle Reductions: Based on current regulatory development, ARB modified the expected emissions reduction of greenhouse gases from the Heavy-Duty Vehicle Greenhouse Gas Emission Reduction (Aerodynamic Efficiency) measure and the Tire Inflation measure. The former measure is now expected to achieve 0.9 $MMTCO_2E$ while the latter is now expected to achieve 0.4 $MMTCO_2E$.

8. Discounting Low Carbon Fuel Standard Reductions: ARB modified the expected emission reductions from the Low Carbon Fuel Standard to reflect overlap in claimed benefits with California's clean car law (the Pavley greenhouse gas vehicle standards). This has the result of discounting expected reduction of greenhouse gas emissions from the Low Carbon Fuel Standard by approximately 10 percent.

[3] Research to help quantify these greenhouse gas emissions reductions is continuing, so only 1 $MMTCO_2E$ of these reductions are currently counted toward the AB 32 goal in this plan. Additional tons will be considered part of the safety margin.

A Balanced and Comprehensive Approach

Meeting the goals of AB 32 will require a coordinated set of strategies to reduce emissions throughout the economy. These strategies will fit within the comprehensive tracking, reporting, and enforcement framework that is already being developed and implemented. By 2020, a hard and declining cap will cover 85 percent of California's greenhouse gas emissions, helping to ensure that we meet our reduction targets on time.

AB 32 lays out a number of important factors that have helped to guide the development of this plan and will continue to be considered as regulations are developed over the next few years. Some of the key criteria that have and will be further considered are: cost-effectiveness; overall societal benefits like energy diversification and public health improvements; minimization of leakage; and impacts on specific sectors like small business and disproportionately impacted communities. The comprehensive approach in the plan reflects a balance among these and other important factors and will help to ensure that California meets its greenhouse gas reduction targets in a way that promotes and rewards innovation, is consistent with and helps to foster economic growth, and delivers improvements to the environment and public health.

Many of the measures in this plan complement and reinforce one another. For instance, the Low Carbon Fuel Standard, which reduces the carbon intensity of transportation fuels sold in California, will work in tandem with technology-forcing regulations designed to reduce greenhouse gas emissions from cars and trucks. Improvements in land use and the ways we grow and build our communities will further reduce emissions from the transportation sector.

Many of the measures also build on highly successful long-standing practices in California—such as energy efficiency and the use of renewable energy resources—that can be accelerated and expanded. Increasing the amount of energy we get from renewable energy sources, including placing solar arrays and solar water heaters on houses throughout California, will be supported by an increase in building standards for energy efficiency. Other measures address the transport and treatment of water throughout the state, reduce greenhouse gas emissions that come from ships in California's ports, and promote changes to agricultural and forestry practices. There are also measures designed to safely reduce or recover a range of very potent greenhouse gases – refrigerants and other industrial gases – that contribute to global warming at a level many times greater per ton emitted than carbon dioxide.

Many of the measures in this plan are designed to take advantage of the economic and innovation-related benefits that market-based compliance strategies can provide. Particularly in light of current economic uncertainty, it is important to ensure that California's climate policies be designed to promote and take advantage of economic opportunities while also cutting greenhouse gas emissions. For instance, the cap-and-trade program creates an opportunity for firms to seek out cost-effective emission reduction strategies and provides an incentive for technological innovation. California's clean car standards, which require manufacturers to meet annual average levels of greenhouse gas emissions for all cars they sell in California, also offer flexibility to help ensure compliance. Under California's clean car standards, manufacturers who exceed compliance standards are permitted to bank credits for future use or sell them to other manufacturers. These types of compliance options will be key in ensuring that we are able to meet our reduction targets in a cost-effective manner.

Working with the Western Climate Initiative

California is working closely with six other states and four Canadian provinces in the Western Climate Initiative (WCI) to design a regional greenhouse gas emissions reduction program that includes a cap-and-trade approach. California's participation in WCI creates an opportunity to provide substantially greater reductions in greenhouse gas emissions from throughout the region than could be achieved by California alone. The larger scope of the program also expands the market for clean technologies and helps avoid leakage, that is, the shifting of emissions from sources within California to sources outside the state.

The WCI partners released the recommended design for a regional cap-and-trade program in September 2008.[4] ARB embraces the WCI effort, and will continue to work with WCI partners. The creation of a robust regional trading system can complement the other policies and measures included in this plan, and provide the means to achieve the reduction of greenhouse gas emissions needed from a wide range of sectors as cost-effectively as possible.

California's Economy, Environment, and Public Health

The approaches in this plan are designed to maximize the benefits that can accompany the transition to a clean energy economy. California has a long and successful track record of implementing environmental policies that also deliver economic benefits. This plan continues in that tradition.

AB 32: Evaluating the Economic Effects

The economic analysis of this plan indicates that implementation of the recommended strategies to address global warming will create jobs and save individual households money.[5] The analysis also indicates that measures in the plan will position California to move toward a more secure, sustainable future where we invest heavily in energy efficiency and clean technologies. The economic analysis indicates that implementation of that forward-looking approach also creates more jobs and saves individual households more money than if California stood by and pursued an unacceptable course of doing nothing at all to address our unbridled reliance on fossil fuels.

Specifically, analysis of the Scoping Plan indicates that projected economic benefits in 2020 compared to the business-as-usual scenario include:

- Increased economic production of $33 billion

[4] Details of the WCI recommendation are provided in Appendix D.

[5] See Appendix G.

- Increased overall gross state product of $7 billion
- Increased overall personal income by $16 billion
- Increased per capita income of $200
- Increased jobs by more than 100,000

Furthermore, the results of the economic analysis may underestimate the economic benefits of the plan since the models that were used do not account for savings that result from the flexibility provided under market-based programs.

AB 32: The Environmental and Public Health Costs of Inaction

A key factor that was not weighed in the overall economic analysis is the potential cost of doing nothing. When these costs are taken into account, the benefits associated with implementing a comprehensive plan to cut greenhouse gas emissions become even clearer. As a state, California is particularly vulnerable to the costs associated with unmitigated climate change.

A summary report from the California Climate Change Center notes that a warming California climate would generate more smoggy days by contributing to ozone formation while also fostering more large brush and forest fires. Continuing increases in global greenhouse gas emissions at business-as-usual rates would result, by late in the century, in California losing 90 percent of the Sierra snow pack, sea level rising by more than 20 inches, and a three to four times increase in heat wave days. These impacts will translate into real costs for California, including flood damage and flood control costs that could amount to several billion dollars in many regions such as the Central Valley, where urbanization and limited river channel capacity already exacerbate existing flood risks.[6] Water supply costs due to scarcity and increased operating costs would increase as much as $689 million per year by 2050.[7] ARB analysis shows that due to snow pack loss, California's snow sports sector would be reduced by $1.4 billion (2006 dollars) annually by 2050 and shed 14,500 jobs; many other sectors of California's economy would suffer as well.

Failing to address climate change also carries with it the risk of substantial public health costs, primarily as a result of rising temperatures. Sustained triple-digit heat waves increase the health risk for several segments of the population, especially the elderly. But higher average temperatures will also increase the interactions of smog-causing chemicals with sunlight and the atmosphere to produce higher volumes of toxic byproducts than would otherwise occur. In the 2006 report to the Governor

---

[6] A Summary Report from: California Climate Change Center. *Our Changing Climate: Assessing the Risks to California.* Document No. CEC-500-2006-077. July 2006. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.PDF (accessed October 12, 2008)

[7] A Report from: California Climate Change Center. *Climate Warming and Water Supply Management in California*. Document No. CEC-500-2005-195-SF. March 2006. pp.13-14 http://www.energy.ca.gov/2005publications/CEC-500-2005-195/CEC-500-2005-195-SF.PDF (accessed October 12, 2008).

from the California Climate Center, it was reported that global increases in temperature will lead to increased concentrations and emissions of harmful pollutants in California.[8] Some cities in California are disproportionately susceptible to temperature increases since they already have elevated pollution levels and are subject to the heat-island effect that reduces nighttime cooling, allowing heat to build up and magnify the creation of additional harmful pollution. Low-income communities are disproportionately impacted by climate change, lacking the resources to avoid or adapt to these impacts. For example, low-income residents are less likely to have access to air conditioning to prevent heat stroke and death in heat waves. For California, then, taking action with other regions and nations to help mitigate the impacts of climate change will help slow temperature rise. This in turn will likely result in fewer premature deaths from respiratory and heat-related causes, and many thousands fewer hospital visits and days of illness.

California cannot avert the impacts of global climate change by acting alone. We can, however, take a national and international leadership role in this effort by demonstrating that taking firm and reasoned steps to address global warming can actually help spur economic growth.

AB 32: Providing Savings for Households and Businesses

This plan builds upon California's thirty-year track record of pioneering energy efficiency programs. Many of the measures in the plan will deliver significant gains in energy efficiency throughout the economy. These gains, even after increases in per unit energy costs are taken into account, will help deliver annual savings of between $400 and $500 on average by 2020 for households, including low-income households.

Businesses, both large and small, will benefit too. By 2020, the efficiency measures in the plan will decrease overall energy expenditures for businesses even after taking into account projected rises in per unit energy costs. Since small businesses spend a greater proportional share of revenue on energy-related costs, they are likely to benefit the most. Furthermore, businesses throughout the state will benefit from the overall economic growth that is projected to accompany implementation of AB 32 between now and 2020.

Similar savings are projected in the transportation sector. By reducing greenhouse gas pollution from more efficient and alternatively-fueled cars and trucks under California's Clean Car law (the Pavley greenhouse gas standards), consumers save on operating costs through reduced fuel use. Although cars will be marginally more expensive, owners will be paid back with savings over the lifetime of the car, and the average new car buyer will have an extra $30 each month for other expenditures. Current estimates indicate that consumer savings in 2020 for California's existing

[8] A Report from: California Climate Change Center. *Scenarios of Climate Change in California: An Overview*. Document No. CEC-500-2005-186-SF. February 2006. http://www.energy.ca.gov/2005publications/CEC-500-2005-186/CEC-500-2005-186-SF.PDF (accessed October 12, 2008)

clean car standards will be over $12 billion. These savings give Californians the ability to invest their dollars in other sectors of the state's economy.

AB 32: Driving Investment and Job Growth

Addressing climate change also provides a strong incentive for investment in California. Our leadership in environmental and energy efficiency policy has already helped attract a large and growing share of the nation's venture capital investment in green technologies. Since AB 32 was signed into law, venture capital investment in California has skyrocketed. In the second quarter of 2008 alone, California dominated world investment in clean technology venture capital, receiving $800 million of the global total of $2 billion.[9]

These investments in building a new clean tech sector also translate directly into job growth. A study by U.C. Berkeley's Energy and Resources Group and Goldman School of Public Policy found that investments in green technologies produce jobs at a higher rate than investments in comparable conventional technologies.[10] And the National Venture Capital Association estimates that each $100 million in venture capital funding helps create 2,700 jobs, $500 million in annual revenues for two decades and many indirect jobs.[11]

AB 32: Improving Public Health

The public health analysis conducted for this Plan indicates that cutting greenhouse gases will also provide a wide range of additional public health and environmental benefits. By 2020, the economic value alone of the additional air-quality related benefits is projected to be on the order of $4.4 billion. Our analysis indicates that implementing the Scoping Plan will result in a reduction of 15 tons per day of combustion-generated soot (PM 2.5) and 61 tons per day of oxides of nitrogen (precursors to smog). These reductions in harmful air pollution would provide the following estimated health benefits in 2020, above and beyond those projected to be achieved as a result of California's other existing public health protection and improvement efforts:

- An estimated 780 premature deaths statewide will be avoided
- Almost 12,000 incidences of asthma and lower respiratory symptoms will be avoided

---

[9] Press Release from Cleantech Network LLC, *Cleantech Venture Investment Reaches Record of $2 Billion in 2008*. July 08, 2008. http://cleantech.com/about/pressreleases/011008.cfm (accessed October 12, 2008)

[10] Report of the Renewable and Appropriate Energy Laboratory. *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?* Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

[11] Report prepared for the National Venture Capital Association. *Venture Impact 2004: Venture Capital Benefits to the U.S. Economy*. Prepared by: Global Insight. June 2004. http://www.globalinsight.com/publicDownload/genericContent/07-20-04_fullstudy.pdf (accessed October 12, 2008)

- 77,000 work loss days will be avoided

In addition to the quantified health benefits, our analysis also indicates that implementation of the measures in the plan will deliver a range of other public health benefits. These include health benefits associated with local and regional transportation-related greenhouse gas targets that will facilitate greater use of alternative modes of transportation such as walking and bicycling. These types of moderate physical activities reduce many serious health risks including coronary heart disease, diabetes, hypertension and obesity.[12] Furthermore, as specific measures are developed, ARB and public health experts will work together to ensure that they are designed with an eye toward capturing a broad range of public health co-benefits.

The results of both the economic and public health analyses are clear: guiding California toward a clean energy future with reduced dependence on fossil fuels will grow our economy, improve public health, protect the environment and create a more secure future built on clean and sustainable technologies.

State Leadership

California is committed to once again lead and support a pioneering effort to protect the environment and improve public health while maintaining a vibrant economy. Every agency, department and division will bring climate change considerations into its policies, planning and analysis, building and expanding current efforts to green its fleet and buildings, and managing its water, natural resources, and infrastructure to reduce greenhouse gas emissions.

In all these efforts, California is exercising a leadership role in global action to address climate change. It is also exemplifying the essential role states play as the laboratories of innovation for the nation. As California has done in the past in addressing emissions that caused smog, the State will continue to develop innovative programs that benefit public health and improve our environment and quality of life.

Moving Beyond 2020

AB 32 requires a return to 1990 emission levels by 2020. The Scoping Plan is designed to achieve that goal. However, 2020 is by no means the end of California's journey to a clean energy future. In fact, that is when many of the strategies laid out in this plan will just be kicking into high gear.

Take, for example, the regional transportation-related greenhouse gas emissions targets. In order to achieve the deep cuts in greenhouse gas emissions we will need beyond 2020 it will be necessary to significantly change California's current land use and transportation planning policies. Although these changes will take time, getting started now will help put California

[12] Appendix H contains a reference list of studies documenting the public health benefits of alternative transportation.

on course to cut statewide greenhouse gas emissions by 80 percent in 2050 as called for by Governor Schwarzenegger.

Similarly, measures like the cap-and-trade program, energy efficiency programs, the California clean car standards, and the renewables portfolio standard will all play central roles in helping California meet its 2020 reduction requirements. Yet, these strategies will also figure prominently in California's efforts beyond 2020. Some of these measures, like energy efficiency programs and the renewables portfolio standard, have already delivered greenhouse gas emissions reduction benefits that will expand over time. Others, like the cap-and-trade program, will put in place a foundation on which to build well into the future. All of these measures, and many others in the plan, will ensure that California meets its 2020 target and is positioned to continue its international role as leader in the fight against global warming to 2050 and beyond.

A Shared Challenge

Californians are already responding to the challenge of reducing greenhouse gas emissions. Over 120 California cities and counties have signed on to the U.S. Conference of Mayors Climate Protection Agreement[13] and many have established offices of climate change and are developing comprehensive plans to reduce their carbon footprint. Well over 300 companies, municipalities, organizations and corporations are members of the California Climate Action Registry, reporting their greenhouse gas emissions on an annual basis. Many other businesses and corporations are making climate change part of their fiscal and strategic planning. ARB encourages these initial efforts and has set in place a policy to support and encourage other voluntary early reductions.

Successful implementation of AB 32 will depend on a growing commitment by a majority of companies to include climate change as an integral part of their planning and operations. Individuals and households throughout the state will also have to take steps to consider climate change at home, at work and in their recreational activities. To support this effort, this plan includes a comprehensive statewide outreach program to provide businesses and individuals with the widest range of information so they can make informed decisions about reducing their carbon footprints.

Californians will not have to wait for decades to see the benefits of a low carbon economy. New homes can achieve a near zero-carbon footprint with better building techniques and existing technologies, such as solar arrays and solar water heaters. Many older homes can be retrofitted to use far less energy than at present. A new generation of vehicles, including plug-in hybrids, is poised to appear in dealers' showrooms, and the development of the infrastructure to support hydrogen fuel cell cars continues. Cities and new developments will be more walkable, public transport will improve, and high-speed rail will give travelers a new clean transportation option.

[13] Mayors Climate Protection Center. *List of Participating Mayors.* http://www.usmayors.org/climateprotection/list.asp (accessed October 12, 2008)

That world is just around the corner. What lies beyond is even more exciting. Where will California be in 2050? By harnessing the ingenuity and creativity of our society and sparking the imagination of the next generation of Californians, California will make the transition to a clean-energy, low-carbon society and become a healthier, cleaner and more sustainable place to live. This plan charts a course toward that future.

ARB invites comment and input from the broadest array of the public and stakeholders as we move forward over the next two years to develop the individual measures, and develop the policies that will move us toward sustainable clean energy and away from fossil fuels. Your participation will help craft the mechanisms and measures to make this plan a reality. This is California's plan and together, we need to make the necessary changes to address the greatest environmental challenge we face. As Governor Schwarzenegger stated when he signed AB 32 into law two years ago, "We owe our children and we owe our grandchildren. We simply must do everything in our power to fight global warming before it is too late."

I. INTRODUCTION: A Framework for Change

California strengthened its commitment to address climate change when Governor Schwarzenegger signed Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006). This groundbreaking legislation represents a turning point for California and makes it clear that a business-as-usual approach toward greenhouse gas emissions is no longer acceptable. In light of the need for strong and immediate action to counter the growing threat of global warming, AB 32 sets forth an aggressive timetable for achieving results.

AB 32 embodies the idea that California can continue to grow and flourish while reducing its greenhouse gas emissions and continuing its long-standing efforts to achieve healthy air, and protect and enhance public health. Achieving these goals will involve every sector of the state's $1.7 trillion economy and touch the life of every Californian.

As the lead agency for implementing AB 32, the California Air Resources Board (ARB or the Board) released a Draft Scoping Plan on June 26, 2008, which laid out a comprehensive statewide plan to reduce California's greenhouse gas emissions to 1990 levels by 2020. This draft plan set forth a comprehensive reduction strategy that combines market-based regulatory approaches, other regulations, voluntary measures, fees, policies, and programs that will significantly reduce emissions of greenhouse gases and help make our state cleaner, more efficient and more secure.

Based upon the numerous comments received on the draft, as well as additional staff analysis, ARB released a *Proposed* Scoping Plan on October 15, 2008. At its November 20 and 21, 2008 meeting, the Board heard staff presentations on the Proposed Scoping Plan and directed staff to make a number of modifications. This *Approved* Scoping Plan incorporates these modifications, as well as corrections from the November 14, 2008 errata sheet, but otherwise reflects the same measures of the Proposed Scoping Plan.

The Board approved this Scoping Plan at its December 11, 2008 meeting, providing specific direction for the State's greenhouse gas emissions reduction program. The recommended measures will be developed into regulations over the next two years, to go into effect by January 1, 2012. As specific measures in the plan are developed, we will update and adjust our regulatory proposals as necessary to ensure that they reflect any new information, additional analyses, new technologies or other factors that emerge during the process.

ARB has conducted a transparent, wide-ranging public process to develop the Scoping Plan, including numerous meetings, workshops, and seminars with stakeholders. Substantial input on the development of the Scoping Plan came from formal advisory committees, meetings with industrial and business groups, non-profit organizations and members of the public, as well as written comments on the Draft Scoping Plan. ARB will continue its outreach activities to seek ongoing public input and will encourage early and continued involvement in the implementation of the plan from all Californians.

A. Summary of Changes from the Draft Scoping Plan

ARB released the June Draft Scoping Plan and requested public comment and input, while continuing to analyze the measures and their impact on California. Since the Draft Scoping Plan release, ARB received almost 1,000 unique written comments as well as hundreds of verbal comments at workshops and in meetings. Taking into account that some written comments were submitted by multiple individuals, all told more than 42,000 people have commented on the draft plan. ARB has also completed detailed economic and public health evaluations of its recommendations.

The key changes between the Draft Scoping Plan and the Scoping Plan are summarized below. The Scoping Plan includes the following modifications:

1. General

- Incorporates economic and public health analyses of the Scoping Plan. These analyses show that the recommendations in the Scoping Plan will have a net positive impact on both the economy and public health. These analyses follow the same methodology used to evaluate the Draft Scoping Plan.
- Provides a "margin of safety" by recommending additional greenhouse gas emissions reduction strategies to account for measures in uncapped sectors that do not achieve the greenhouse gas emissions reductions estimated in the Scoping Plan. Along with the certainty provided by the cap, this will ensure that the 2020 target is met.
- Expands the discussion of workforce development, education, and labor to more fully reflect existing activities and the role of other state agencies in ensuring an adequate green technology workforce.
- Assesses how well the recommended measures put California on the long-term reduction trajectory needed to do our part to stabilize the global climate.
- Describes California's role in the West Coast Regional Carbon Sequestration Partnership (WESTCARB), a public-private collaboration to characterize regional carbon capture and sequestration opportunities, and expresses support for near-term advancement of the technology and monitoring of its development. Acknowledges the important role of terrestrial sequestration.
- Provides greater detail on the mechanisms to be developed to encourage voluntary early action.
- Provides additional detail on implementation, tracking and enforcement of the recommended actions, including the important role of local air districts.

- Evaluates the potential environmental impacts of the Scoping Plan under the California Environmental Quality Act (CEQA). This evaluation is contained in Appendix J.

2. Proposed Measures

- Provides greater detail on the proposed cap-and-trade program including more detail on the allocation and auction of allowances, and clarification of the proposed role of offsets.
- Re-evaluates the potential benefits from regional targets for transportation-related greenhouse gases in consultation with regional planning organizations and researchers at U.C. Berkeley. Based on this information, ARB increased the anticipated greenhouse gas emissions reductions for Regional Transportation-Related Greenhouse Gas Targets from 2 to 5 million metric tons of CO_2 equivalent ($MMTCO_2E$).
- In recognition of the importance of local governments in the successful implementation of AB 32, adds a section describing this role and recommends a greenhouse gas emissions reduction target for local government municipal and community-wide emissions of a 15 percent reduction from current levels by 2020 to parallel the State's target.
- Adds four measures to address emissions from industrial sources. These proposed measures would regulate fugitive emissions from oil and gas recovery and gas transmission activities, reduce refinery flaring, and remove the methane exemption for refineries. These proposed measures are anticipated to provide 1.5 $MMTCO_2E$ of greenhouse gas reductions in 2020.
- In consultation with the California Integrated Waste Management Board, re-assesses potential measures in the Recycling and Waste sector. As a result of this assessment, ARB increased the reduction of greenhouse gas emissions that can ultimately be anticipated from the Recycling and Waste Sector from 1 to 10 $MMTCO_2E$, recommending measures to move toward high recycling and zero-waste. Research to help quantify these greenhouse gas emissions is continuing, so only 1 $MMTCO_2E$ of these reductions is currently counted towards the AB 32 goal in this plan.
- Estimates the potential reduction of greenhouse gas emissions from the Green Building sector. Green building systems have the potential to reduce approximately 26 $MMTCO_2E$ of greenhouse gas emissions. Since most of these emissions reductions are counted in the Electricity, Commercial/Residential Energy, Water or Waste sectors, emission reductions in the Green Building sector are not separately counted toward the AB 32 goal.
- Adds a High Global Warming Potential (GWP) Mitigation Fee measure to ensure that the climate impact of these gases is reflected in their price to encourage reduced use and end-of-life losses, as well as the development of alternatives.
- Reduces the expected greenhouse gas emissions reduction from the Heavy-Duty Vehicle Greenhouse Gas Emissions Reduction (Aerodynamic Efficiency) measure and the Tire Inflation measure based on ongoing regulatory

development. The Heavy-Duty Vehicle Greenhouse Gas Emissions Reduction (Aerodynamic Efficiency) measure is now expected to achieve 0.9 $MMTCO_2E$ and the Tire Inflation measure is now expected to achieve 0.4 $MMTCO_2E$.

- Modifies the expected reduction of greenhouse gas emissions from the Low Carbon Fuel Standard to account for potential overlap of benefits with the Pavley greenhouse gas vehicle standards. ARB discounted the expected emission reductions from the Low Carbon Fuel Standard by 10 percent.
- After further evaluation, moves the Heavy-Duty Truck Efficiency measure to the Goods Movement measure. ARB expects that market dynamics will provide an inducement to improve heavy-duty truck efficiency, and reductions in greenhouse gases in the future. ARB would consider pursuing direct requirements to reduce greenhouse gases if truck efficiency does not improve in the future.

B. Background

1. Climate Change Policy in California

California first addressed climate change in 1988 with the passage of AB 4420 (Sher, Chapter 1506, Statutes of 1988). This bill directed the California Energy Commission (CEC) to study global warming impacts to the state and develop an inventory of greenhouse gas emissions sources. In 2000, SB 1771 (Sher, Chapter 1018, Statutes of 2000) established the California Climate Action Registry to allow companies, cities and government agencies to voluntarily record their greenhouse gas emissions in anticipation of a possible program that would allow them to be credited for early reductions.

In 2001, the United Nations' Intergovernmental Panel on Climate Change (IPCC) reported that "there is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities." The following year, AB 1493 (Pavley, Chapter 200, Statutes of 2002) was signed into law, requiring ARB to develop regulations to reduce greenhouse gas emissions from passenger vehicles, light-duty trucks and non-commercial vehicles sold in California.

Recognizing the value of regional partners in addressing climate change, the governors of California, Washington, and Oregon created the West Coast Global Warming Initiative in 2003 with provisions for the states to work together on climate change-related programs.

Two years later Governor Schwarzenegger signed Executive Order S-3-05, calling for the State to reduce greenhouse gas emissions to 1990 levels by 2020 and to reduce greenhouse gas emissions to 80 percent below 1990 levels by 2050. The 2020 goal was established to be an aggressive, but achievable, mid-term target, and the 2050 greenhouse gas emissions reduction goal represents the level scientists believe is necessary to reach levels that will stabilize climate.

In 2006, SB 1368 (Perata, Chapter 598, Statutes of 2006) created greenhouse gas performance standards for new long-term financial investments in base-load electricity generation serving California customers. This law is designed to help spur the transition toward cleaner energy in California by placing restrictions on the ability of utilities to build new carbon-intensive plants or enter into new contracts with high carbon sources of electricity. Expiration of existing utility long-term contracts with coal plants will reduce greenhouse gas emissions when such generation is replaced by lower greenhouse gas-emitting resources. These reductions will reduce the need for utilities to submit allowances to comply with the cap-and-trade program.

2. Assembly Bill 32: The Global Warming Solutions Act

In 2006, the Legislature passed and Governor Schwarzenegger signed AB 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law. It directed ARB to begin developing discrete early actions to reduce greenhouse gases while also preparing a Scoping Plan to identify how best to reach the 2020 limit. The reduction measures to meet the 2020 target are to become operative by 2012.

AB 32 includes a number of specific requirements for ARB:

- *Identify the statewide level of greenhouse gas emissions in 1990 to serve as the emissions limit to be achieved by 2020 (Health and Safety Code (HSC) §38550).* In December 2007, the Board approved the 2020 emission limit of 427 million metric tons of carbon dioxide equivalent ($MMTCO_2E$) of greenhouse gases.
- *Adopt a regulation requiring the mandatory reporting of greenhouse gas emissions (HSC §38530).* In December 2007, the Board adopted a regulation requiring the largest industrial sources to report and verify their greenhouse gas emissions. The reporting regulation serves as a solid foundation to determine greenhouse gas emissions and track future changes in emission levels.
- *Identify and adopt regulations for Discrete Early Actions that could be enforceable on or before January 1, 2010 (HSC §38560.5).* The Board identified nine Discrete Early Action measures including potential regulations affecting landfills, motor vehicle fuels, refrigerants in cars, port operations and other sources in 2007. The Board has already approved two Discrete Early Action measures (ship electrification at ports and reduction of high GWP gases in consumer products). Regulatory development for the remaining measures is ongoing.
- *Ensure early voluntary reductions receive appropriate credit in the implementation of AB 32 (HSC §38562(b)(3)).* In February 2008, the Board approved a policy statement encouraging voluntary early actions and establishing a procedure for project proponents to submit quantification methods to be evaluated by ARB. ARB, along with California's local air districts and the California Climate Action Registry, is working to implement this program. Voluntary programs are discussed further in Chapter II and in Chapter IV.

- *Convene an Environmental Justice Advisory Committee (EJAC) to advise the Board in developing the Scoping Plan and any other pertinent matter in implementing AB 32 (HSC §38591).* The EJAC has met 12 times since early 2007, providing comments on the proposed Early Action measures and the development of the Scoping Plan, and submitted its comments and recommendations on the draft Scoping Plan in October 2008. ARB will continue to work with The EJAC as AB 32 is implemented.
- *Appoint an Economic and Technology Advancement Advisory Committee (ETAAC) to provide recommendations for technologies, research and greenhouse gas emission reduction measures (HSC §38591).* After a year-long public process, The ETAAC submitted a report of their recommendations to the Board in February 2008. The ETAAC also reviewed and provided comments on the Draft Scoping Plan.

3. Climate Action Team

In addition to establishing greenhouse gas emissions reduction targets for California, Executive Order S-3-05 established the Climate Action Team (CAT) for State agencies in 2005. Chaired by the Secretary of the California Environmental Protection Agency (CalEPA), the CAT has helped to direct State efforts on the reduction of greenhouse gas emissions and engage key State agencies including ARB. The Health and Human Services Agency, represented by the Department of Public Health, is the newest member of the CAT. Based on numerous public meetings and the review of thousands of submitted comments, the CAT released its first report in March 2006, identifying key carbon reduction recommendations for the Governor and Legislature.

Climate Action Team
California Environmental Protection Agency
Business, Transportation, and Housing Agency
Health and Human Services Agency
Resources Agency
State and Consumer Services Agency
Governor’s Office of Planning and Research
Air Resources Board
California Energy Commission
California Public Utilities Commission
Department of Food and Agriculture
Department of Forestry and Fire Protection
Department of General Services
Department of Parks and Recreation
Department of Transportation
Department of Water Resources
Integrated Waste Management Board
State Water Resources Control Board

In April 2007, the CAT released a second report, “Proposed Early Actions to Mitigate Climate Change in California,” which details numerous strategies that should be initiated prior to the 2012 deadline for other climate action regulations and efforts.

AB 32 recognizes the essential role of the CAT in coordinating overall climate policy. AB 32 does not affect the existing authority of other state agencies, and in addition to

ARB, many state agencies will be responsible for implementing the measures and strategies in this plan. The CAT is central to the success of AB 32, which requires an unprecedented level of cooperation and coordination across State government. The CAT provides the leadership for these efforts and helps ARB work closely with our state partners on the development and implementation of the strategies in the Scoping Plan.

There are currently 12 subgroups within the CAT – nine that address specific economic sectors, and three that were formed to analyze broad issues related to implementing a multi-sector approach to greenhouse gas emissions reduction efforts. The CAT sector-based subgroups include: Agriculture, Cement, Energy, Forest, Green Buildings, Land Use, Recycling and Waste Management, State Fleet, and Water-Energy. The members of these subgroups are drawn from departments that work with or regulate industries in the sector. ARB participated in each of the subgroups. All of the subgroups held public meetings and solicited public input, and many had multiple public workshops.

In March 2008, the subgroups collectively submitted more than 100 greenhouse gas emissions reduction measures to ARB for consideration in the Draft Scoping Plan. Many of those recommendations are reflected in this plan, and a number of them focus on reducing greenhouse gas emissions from energy production and use.

Through the Energy Subgroup the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) are conducting a joint proceeding to provide recommendations on how best to address electricity and natural gas in the implementation of AB 32, including evaluation of how the Electricity sector might best participate in a cap-and-trade program. The two Commissions forwarded interim recommendations to ARB in March 2008 that supported inclusion of the Electricity sector in a multi-sector cap-and-trade program, and measures to increase the penetration of energy efficiency programs in both buildings and appliances and to increase renewable energy sources. The two Commissions have developed a second proposed decision that was released in September 2008. This proposed decision provides more detailed recommendations that relate to the electricity and natural gas sectors. Because implementation of the Scoping Plan will require careful coordination with the State's energy policy, ARB will continue working closely with the two Commissions on this important area during the implementation of the recommendations in the Scoping Plan.

There are also three subgroups which are not sector-specific. The Economic Subgroup reviewed cost information associated with potential measures that were included in the 2006 CAT report with updates reflected in the report, "Updated Macroeconomic Analysis of Climate Strategies," in October 2007. This report provided an update of the macroeconomic analysis presented in the March 2006 CAT report to Governor Schwarzenegger and the Legislature. The Research Subgroup coordinates climate change research and identifies opportunities for collaboration, and is presently working on a report to the Governor. The State Operations Subgroup has been created to work with State agencies to create a statewide plan to reduce State government's greenhouse gas emissions by a minimum of 30 percent by 2020.

In the first quarter of 2009, the Climate Action Team will release a report on its activities outside of its involvement in the development of the Scoping Plan. The CAT report will focus on several cross-cutting topics with which members of the CAT have been involved since the publication of the 2006 CAT report. The topics to be covered include research on the physical and consequent economic impacts of climate change as well as climate change research coordination efforts among the CAT members. There will also be an update on the important climate change adaptation efforts led by the Resources Agency and a discussion of cross-cutting issues related to environmental justice concerns. The CAT report will be released in draft form and will be available for public review in December 2008.

4. Development of the Greenhouse Gas Emission Reduction Strategy

In developing the Scoping Plan, ARB considered the State's existing climate change policy initiatives and the Early Action measures identified by the Board. Several advisory groups were formed to assist ARB in developing the Scoping Plan, including the Environmental Justice Advisory Committee (EJAC), the Economic and Technology Advancement Committee (ETAAC), and the Market Advisory Committee (MAC).

The Environmental Justice Advisory Committee (HSC §38591(a) et seq) advises ARB on development of the Scoping Plan and any other pertinent matter in implementing AB 32. The Board appoints its members, based on nominations received from environmental justice organizations and community groups.

The Economic and Technology Advancement Advisory Committee (HSC §38591(d)) includes members who are appointed by the Board based on expertise in fields of business, technology research and development, climate change, and economics. The ETAAC advises ARB on activities that will facilitate investment in, and implementation of, technological research and development opportunities, funding opportunities, partnership development, technology transfer opportunities, and related areas that lead to reductions of greenhouse gas emissions.

Members of the Market Advisory Committee (created under Executive Order S-20-06) were appointed by the Secretary of CalEPA based on their expertise in economics and climate change. The MAC advised ARB on the design of a cap-and-trade program for reducing greenhouse gas emissions.

Along with input from the advisory groups, ARB received submittals to a public solicitation for ideas, and numerous comments during public workshops, workgroup meetings, community meetings, and meetings with stakeholder groups. ARB held numerous workshops on the Draft Scoping Plan and convened workgroup meetings focused on program design and economic analysis. ARB and other involved State agencies also held sector-specific technical workshops to look in greater detail at potential emissions reduction measures.

ARB also looked outward to examine programs at the regional, national and international levels. ARB met with and learned from experts from the European Union, the United Kingdom, Japan, Australia, the United Nations, the Regional Greenhouse Gas Initiative, the RECLAIM program, and the U.S. Environmental Protection Agency (U.S. EPA).

After the release of the Draft Scoping Plan, ARB conducted workshops and community meetings around the state to solicit public input. The Environmental Justice Advisory Committee and the Economic and Technology Advancement Advisory Committee held meetings to review and provide additional comments on the Draft Scoping Plan. In addition, ARB held meetings with numerous stakeholder groups to discuss specific greenhouse gas emissions reduction measures.

As described before, ARB has reviewed and considered both the written comments and the verbal comments received at the public workshops and meetings with stakeholders. This input, along with additional analysis, has ultimately shaped this Scoping Plan.

5. Implementation of the Scoping Plan

The foundation of the Scoping Plan's strategy is a set of measures that will cut greenhouse gas emissions by nearly 30 percent by the year 2020 as compared to business as usual and put California on a course for much deeper reductions in the long term. In addition to pursuing the reduction of greenhouse gas emissions, other strategies to mitigate climate change, such as carbon capture and storage (underground geologic storage of carbon dioxide), should also be further explored. And, as greenhouse gas reduction measures are implemented, we will continually evaluate how these measures can be optimized to also help deliver a broad range of public health benefits.

Most of the measures in this Scoping Plan will be implemented through the full rulemaking processes at ARB or other agencies. These processes will provide opportunity for public input as the measures are developed and analyzed in more detail. This additional analysis and public input will likely provide greater certainty about the estimates of costs and expected greenhouse gas emission reductions, as well as the design details that are described in this Scoping Plan. With the exception of Discrete Early Actions, which will be in place by January 1, 2010, other regulations are expected to be adopted by January 1, 2011 and take effect at the beginning of 2012.

Some of the measures in the plan may deliver more emission reductions than we expect; others less. It is also very likely that we will figure out new and better ways to cut greenhouse gas emissions as we move forward. New technologies will no doubt be developed, and new ideas and strategies will emerge. The Scoping Plan puts

California squarely on the path to a clean energy future but it also recognizes that adjustments will probably need to occur along the way and that as additional tools become available they will augment, and in some cases perhaps even replace, existing approaches.

California will not be implementing the measures in this Plan in a vacuum. Significant new action on climate policy is likely at the federal level and California and its partners in the Western Climate Initiative are working together to create a regional effort for achieving significant reductions of greenhouse gas emissions throughout the western United States and Canada. California is also developing a state Climate Adaptation Strategy to reduce California's vulnerability to known and projected climate change impacts.

ARB and other State agencies will continue to monitor, lead and participate in these broader activities. ARB will adjust the measures described here as necessary to ensure that California's program is designed to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas emissions reduction programs. (HSC §38564)

6. Climate Change in California

The impacts of climate change on California and its residents are occurring now. Of greater concern are the expected future impacts to the state's environment, public health and economy, justifying the need to sharply cut greenhouse gas emissions.

In the Findings and Declarations for AB 32, the Legislature found that:

> "The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to the marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other health-related problems."

The Legislature further found that global warming would cause detrimental effects to some of the state's largest industries, including agriculture, winemaking, tourism, skiing, commercial and recreational fishing, forestry, and the adequacy of electrical power.

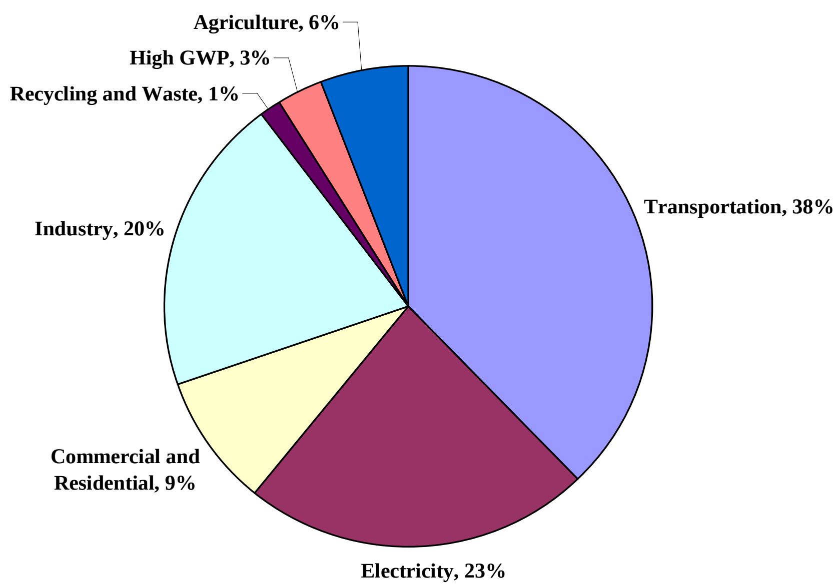
The impacts of global warming are already being felt in California. The Sierra snowpack, an important source of water supply for the state, has shrunk 10 percent in the last 100 years. It is expected to continue to decrease by as much as 25 percent by 2050. World-wide changes are causing sea levels to rise – about 8 inches of increase has been recorded at the Golden Gate Bridge over the past 100 years – threatening low coastal areas with inundation and serious damage from storms.

C. California's Greenhouse Gas Emissions and the 2020 Target

California is the fifteenth largest emitter of greenhouse gases on the planet, representing about two percent of the worldwide emissions. Although carbon dioxide is the largest contributor to climate change, AB 32 also references five other greenhouse gases: methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). Many other gases contribute to climate change and would also be addressed by measures in this Scoping Plan.

Figure 1 and Table 1 show 2002 to 2004 average emissions and estimates for projected emissions in 2020 without any greenhouse gas reduction measures (business-as-usual case). The 2020 business-as-usual forecast does not take any credit for reductions from measures included in this Plan, including the Pavley greenhouse gas emissions standards for vehicles, full implementation of the Renewables Portfolio Standard beyond current levels of renewable energy, or the solar measures. Additional information about the assumptions in the 2020 forecast is provided in Appendix F.

Figure 1: California's Greenhouse Gas Emissions (2002-2004 Average)[14]



As seen in Figure 1, the Transportation sector – largely the cars and trucks that move goods and people – is the largest contributor with 38 percent of the state's total greenhouse gas emissions. Table 1 shows that if we take no action, greenhouse gas emissions in the

[14] Air Resources Board. Greenhouse Gas Inventory. http://www.arb.ca.gov/cc/inventory/inventory.htm (accessed October 12, 2008)

Transportation sector are expected to grow by approximately 25 percent by 2020 (an increase of 46 $MMTCO_2E$).

The Electricity and Commercial/Residential Energy sector is the next largest contributor with over 30 percent of the statewide greenhouse gas emissions. Although electricity imported into California accounts for only about a quarter of our electricity, imports contribute more than half of the greenhouse gas emissions from electricity because much of the imported electricity is generated at coal-fired power plants. AB 32 specifically requires ARB to address emissions from electricity sources both inside and outside of the state.

California's Industrial sector includes refineries, cement plants, oil and gas production, food processors, and other large industrial sources. This sector contributes almost 20 percent of California's greenhouse gas emissions, but the sector's emissions are not projected to grow significantly in the future. The sector termed recycling and waste management is a unique system, encompassing not just emissions from waste facilities but also the emissions associated with the production, distribution and disposal of products throughout the economy.

Although high global warming potential (GWP) gases are a small contributor to historic greenhouse gas emissions, levels of these gases are projected to increase sharply over the next several decades, making them a significant source by 2020.

The Forest sector is unique in that forests both emit greenhouse gases and uptake carbon dioxide (CO_2). While the current inventory shows forests as a sink of 4.7 $MMTCO_2E$, carbon sequestration has declined since 1990. For this reason, the 2020 projection assumes no net emissions from forests.

The agricultural greenhouse gas emissions shown are largely methane emissions from livestock, both from the animals and their waste. Emissions of greenhouse gases from fertilizer application are also important contributors from the Agricultural sector. ARB has begun a research program to better understand the variables affecting these emissions. Opportunities to sequester CO_2 in the Agricultural sector may also exist; however, additional research is needed to identify and quantify potential sequestration benefits.

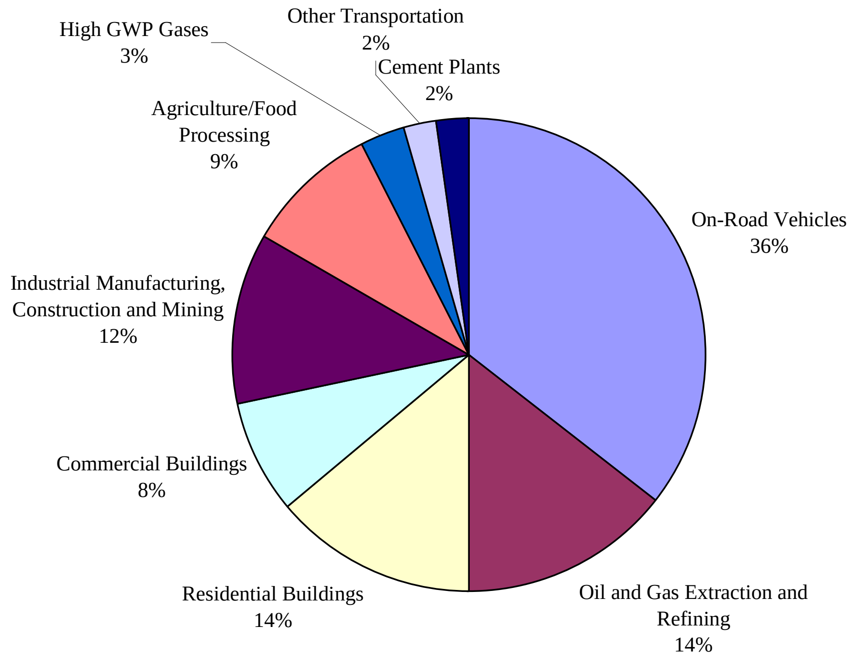
In December 2007, ARB approved a greenhouse gas emissions target for 2020 equivalent to the state's calculated greenhouse gas emissions level in 1990. ARB developed the 2020 target after extensive technical work and a series of stakeholder meetings. The 2020 target of 427 $MMTCO_2E$ requires the reduction of 169 $MMTCO_2E$, or approximately 30 percent, from the state's projected 2020 emissions of 596 $MMTCO_2E$ (business-as-usual) and the reduction of 42 $MMTCO_2E$, or almost 10 percent, from 2002-2004 average emissions.

Table 1: 2002-2004 Average Emissions and 2020 Projected Emissions (Business-as-Usual)[15] ($MMTCO_2E$)

Sector	2002-2004 Average Emissions	Projected 2020 Emissions [BAU]
Transportation	179.3	225.4
Electricity	109.0	139.2
Commercial and Residential	41.0	46.7
Industry	95.9	100.5
Recycling and Waste	5.6	7.7
High GWP	14.8	46.9
Agriculture	27.7	29.8
Forest Net Emissions	-4.7	0.0
Emissions Total	**469**	**596**

Figure 2 presents California's historic greenhouse gas emissions in a different way – based not on the source of the emissions, but on the end use. This chart highlights the importance of addressing on-road transportation sources of greenhouse gas emissions, as well as the significant contribution from the heating, cooling, and lighting of buildings.

Figure 2: California's Greenhouse Gas Emissions – A Demand-Side View –



[15] Ibid.

The data shown in this section provide two ways to look at California's greenhouse gas profile – emissions-based and end use (demand side)-based. While it is possible to illustrate the inventory many different ways, no chart or graph can fully display how diverse economic sectors fit together. California's economy is a web of activity where seemingly independent sectors and subsectors operate interdependently and often synergistically. For example, reductions in water use reduce the need to pump water, directly lowering electricity use and associated greenhouse gas emissions. Similarly, reducing the generation of waste reduces the need to transport the waste to landfills – lowering transportation emissions and, possibly, landfill methane emissions. Increased recycling or re-use reduces the carbon emissions embedded in products – it takes less energy to make a soda can made from recycled aluminum than from virgin feedstock.

The measures included in this Scoping Plan are identified discretely, but many impact each other, and changes in one measure can directly overlap and have a ripple effect on the efficacy and success of other measures. The measures and policies outlined in this Plan reflect these interconnections, and highlight the need for all agencies to work collaboratively to implement the Scoping Plan.

II. RECOMMENDED ACTIONS

Achieving the goals of AB 32 in a cost-effective manner will require a wide range of approaches. Every part of California's economy needs to play a role in reducing greenhouse gas emissions. ARB's comprehensive greenhouse gas emissions inventory lists emission sources ranging from the largest refineries and power plants to small industrial processes and farm livestock. The recommended measures were developed to reduce greenhouse gas emissions from key sources and activities while improving public health, promoting a cleaner environment, preserving our natural resources, and ensuring that the impacts of the reductions are equitable and do not disproportionately impact low-income and minority communities. These measures also put the state on a path to meet the long-term 2050 goal of reducing California's greenhouse gas emissions to 80 percent below 1990 levels. This trajectory is consistent with the reductions that are needed globally to help stabilize the climate. While the scale of this effort is considerable, our experience with cultural and technological changes makes California well-equipped to handle this challenge.

ARB evaluated a comprehensive array of approaches and tools to achieve these emission reductions. Reducing greenhouse gas emissions from the wide variety of sources can best be accomplished though a cap-and-trade program along with a mix of complementary strategies that combine market-based regulatory approaches, other regulations, voluntary measures, fees, policies, and programs. ARB will monitor implementation of these measures to ensure that the State meets the 2020 limit on greenhouse gas emissions.

An overall limit on greenhouse gas emissions from most of the California economy – the "capped sectors" – will be established by the cap-and-trade program. (The basic elements of the cap-and-trade program are described later in this chapter.) Within the capped sectors, some of the reductions will be accomplished through direct regulations such as improved building efficiency standards and vehicle efficiency measures. Whatever additional reductions are needed to bring emissions within the cap are accomplished through price incentives posed by emissions allowance prices. Together, direct regulation and price incentives assure that emissions are brought down cost-effectively to the level of the overall cap. ARB also recommends specific measures for the remainder of the economy – the "uncapped sectors."

Key elements of California's recommendations for reducing its greenhouse gas emissions to 1990 levels by 2020 include:

- **Expanding and strengthening existing energy efficiency programs as well as building and appliance standards;**
- **Achieving a statewide renewables energy mix of 33 percent;**
- **Developing a California cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system;**
- **Establishing targets for transportation-related greenhouse gas emissions for regions throughout California and pursuing policies and incentives to achieve those targets;**
- **Adopting and implementing measures pursuant to existing State laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard; and**
- **Creating targeted fees, including a public goods charge on water use, fees on high global warming potential gases, and a fee to fund the administrative costs of the State's long-term commitment to AB 32 implementation.**

The recommended greenhouse gas emissions reduction measures are listed in Table 2 and are summarized in Section C below. The total reduction for the recommended measures slightly exceeds the 169 $MMTCO_2E$ of reductions estimated in the Draft Scoping Plan. This is the net effect of adding several measures and adjusting the emission reduction estimates for some other measures. The 2020 emissions cap in the cap-and-trade program is preserved at the same level as in the Draft Scoping Plan (365 $MMTCO_2E$).

The measures listed in Table 2 lead to emissions reductions from sources within the capped sectors (146.7 $MMTOCO_2E$) and from sources or sectors not covered by cap-and-trade (27.3 $MMTCO_2E$). As mentioned, within the capped sectors the reductions derive both from direct regulation and from the incentives posed by allowance prices. Further discussion of how the cap-and-trade program and the complementary measures work together to achieve the overall target is provided below.

Table 2 also lists several other recommended measures which will contribute toward achieving the 2020 statewide goal, but whose reductions are not (for various reasons including the potential for double counting) additive with the other measures. Those measures and the basis for not including their reductions are further discussed in Section C.

Table 2: Recommended Greenhouse Gas Reduction Measures

Recommended Reduction Measures		Reductions Counted Towards 2020 Target ($MMTCO_2E$)
ESTIMATED REDUCTIONS RESULTING FROM THE COMBINATION OF CAP-AND-TRADE PROGRAM AND COMPLEMENTARY MEASURES		**146.7**
California Light-Duty Vehicle Greenhouse Gas Standards • Implement Pavley standards • Develop Pavley II light-duty vehicle standards	31.7	
Energy Efficiency • Building/appliance efficiency, new programs, etc. • Increase CHP generation by 30,000 GWh • Solar Water Heating (AB 1470 goal)	26.3	
Renewables Portfolio Standard (33% by 2020)	21.3	
Low Carbon Fuel Standard	15	
Regional Transportation-Related GHG Targets[16]	5	
Vehicle Efficiency Measures	4.5	
Goods Movement • Ship Electrification at Ports • System-Wide Efficiency Improvements	3.7	
Million Solar Roofs	2.1	
Medium/Heavy Duty Vehicles • Heavy-Duty Vehicle Greenhouse Gas Emission Reduction (Aerodynamic Efficiency) • Medium- and Heavy-Duty Vehicle Hybridization	1.4	
High Speed Rail	1.0	
Industrial Measures (for sources covered under cap-and-trade program) • Refinery Measures • Energy Efficiency & Co-Benefits Audits	0.3	
Additional Reductions Necessary to Achieve the Cap	34.4	
ESTIMATED REDUCTIONS FROM UNCAPPED SOURCES/SECTORS		**27.3**
High Global Warming Potential Gas Measures	20.2	
Sustainable Forests	5.0	
Industrial Measures (for sources not covered under cap and trade program) • Oil and Gas Extraction and Transmission	1.1	
Recycling and Waste (landfill methane capture)	1.0	
TOTAL REDUCTIONS COUNTED TOWARDS 2020 TARGET		**174**

Other Recommended Measures	Estimated 2020 Reductions ($MMTCO_2E$)
State Government Operations	1-2
Local Government Operations	TBD
Green Buildings	26
Recycling and Waste • Mandatory Commercial Recycling • Other measures	9
Water Sector Measures	4.8
Methane Capture at Large Dairies	1.0

[16] This number represents an estimate of what may be achieved from local land use changes. It is not the SB 375 regional target. ARB will establish regional targets for each Metropolitan Planning Organization (MPO) region following the input of the Regional Targets Advisory Committee and a public consultation process with MPOs and other stakeholders per SB 375.

The development of a California cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system is a central feature of the overall recommendation. This program will lead to prices on greenhouse gas emissions, prices that will spur reductions in greenhouse gas emissions throughout the California economy, through application of existing technologies and through the creation of new technological and organizational options. The rationale for combining a cap-and-trade program with complementary measures was outlined by the Market Advisory Committee, which noted the following in its recommendations to the ARB:

> Before setting out the key design elements of a cap-and-trade program it is important to explain how the proposed emissions trading approach relates to other policy measures. The following considerations seem especially relevant:
>
> - The emissions trading program puts a cap on the total emissions generated by facilities covered under the system. Because a certain number of emissions allowances are put in circulation in each compliance period, this approach provides a measure of certainty about the total quantity of emissions that will be released from entities covered under the program.
> - The market price of emissions allowances yields an enduring price signal for GHG emissions across the economy. This price signal provides incentives for the market to find new ways to reduce emissions.
> - By itself, a cap-and-trade program alone will not deliver the most efficient mitigation outcome for the state. There is a strong economic and public policy basis for other policies that can accompany an emissions trading system. [17]

The Economic and Technology Advancement Advisory Committee (ETAAC) also addressed the benefits associated with a combined policy of cap and trade and complementary measures.

> A declining cap can send the right price signals to shape the behavior of consumers when purchasing products and services. It would also shape business decisions on what products to manufacture and how to manufacture them. Establishing a price for carbon and other GHG emissions can efficiently tilt decision-making toward cleaner alternatives. This cap and trade approach (complemented by technology-forcing performance standards) avoids the danger of having government or other centralized decision-makers choose specific technologies, thereby limiting the flexibility to allow other options to emerge on a level playing field.

[17] Recommendations of the Market Advisory Committee to the California Air Resources Board. *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. June 30, 2007. p. 19. http://www.climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF (accessed October 12, 2008)

> If markets were perfect, such a cap and trade system would bring enough new technologies into the market and stimulate the necessary industrial RD&D to solve the climate change challenge in a cost effective manner. As the Market Advisory Committee notes, however, placing a price on GHG emissions addresses only one of many market failures that impede solutions to climate change. Additional market barriers and co-benefits would not be addressed if a cap and trade system were the only state policy employed to implement AB 32. Complementary policies will be needed to spur innovation, overcome traditional market barriers (e.g., lack of information available to energy consumers, different incentives for landlords and tenants to conserve energy, different costs of investment financing between individuals, corporations and the state government, etc.) and address distributional impacts from possible higher prices for goods and services in a carbon-constrained world.[18]

The Environmental Justice Advisory Committee (EJAC) also supports an approach that includes a price on carbon along with complementary measures. Although the EJAC recommends that the carbon price be established through a carbon fee rather than through a cap-and-trade program, they recognize the importance of mutually supportive policies:

> California should establish a three-pronged approach for addressing greenhouse gases: (1) adopting standards and regulations; (2) providing incentives; and (3) putting a price on carbon via a carbon fee. The three pieces support one another and no single prong can work without equally robust support from the others.[19]

In keeping with the rationale outlined above, ARB finds that it is critically important to include complementary measures directed at emission sources that are included in the cap-and-trade program. These measures are designed to achieve cost-effective emissions reductions while accelerating the necessary transition to the low-carbon economy required to meet the 2050 target:

- The already adopted Light-Duty Vehicle Greenhouse Gas Standards are designed to accelerate the introduction of low-greenhouse gas emitting vehicles, reduce emissions and save consumers money at the pump.
- The Low Carbon Fuel Standard (LCFS) is a flexible performance standard designed to accelerate the availability and diversity of low-carbon fuels by taking into consideration the full life-cycle of greenhouse gas emissions. The LCFS will reduce emissions and make our economy more resilient to future petroleum price volatility.
- The Regional Transportation-Related Greenhouse Gas Targets provide incentives for channeling investment into integrated development patterns and transportation

---

[18] Recommendations of the Economic and Technical Advancement Advisory Committee (ETAAC), Final Report. *Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California*. February 14, 2008. pp. 1-4 http://www.arb.ca.gov/cc/etaac/ETAACFinalReport2-11-08.pdf (accessed October 12, 2008)

[19] Recommendations and Comments of the Environmental Justice Advisory Committee on the Implementation of the Global Warming Solutions Act of 2006 (AB32) on the Draft Scoping Plan. October 2008. p. 10. http://www.arb.ca.gov/cc/ejac/ejac_comments_final.pdf (accessed October 12, 2008)

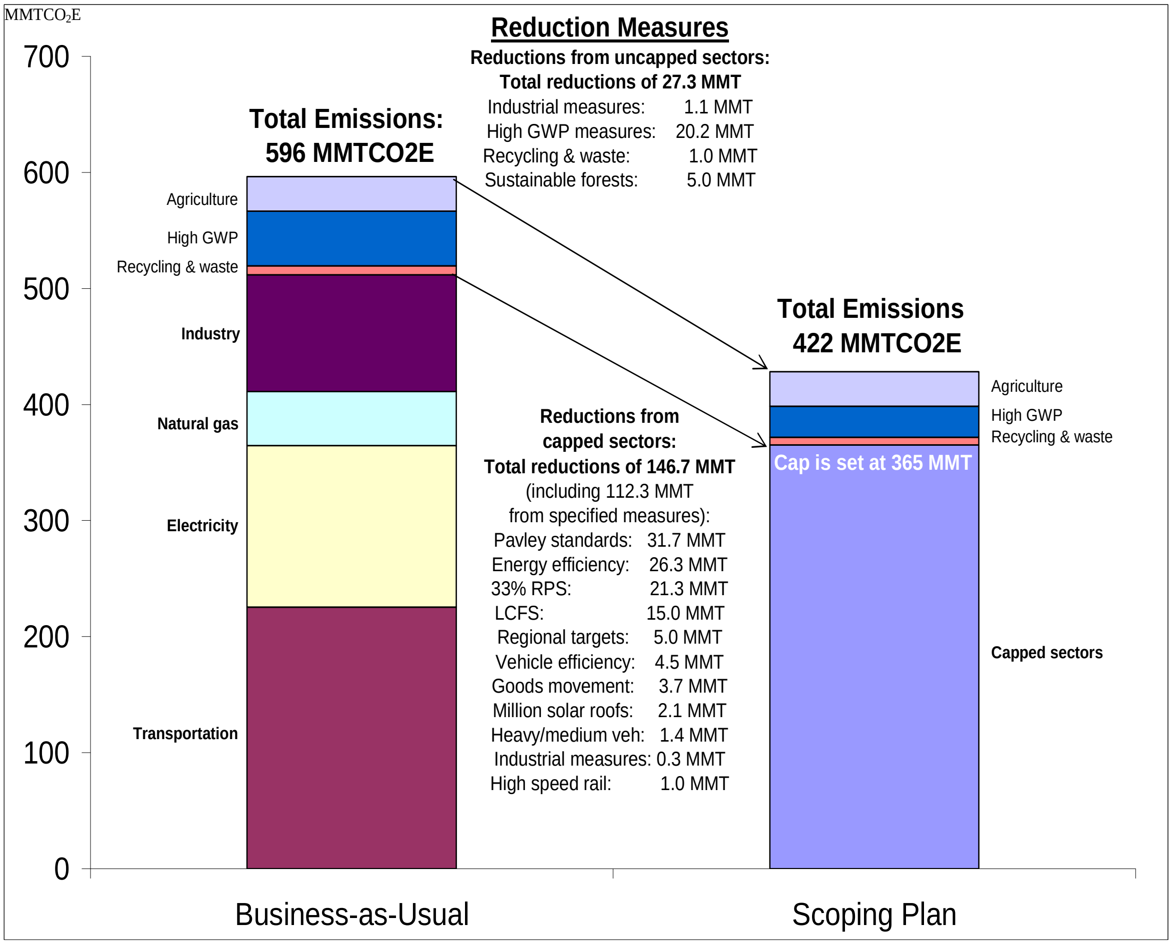
infrastructure, through improved planning. Improved planning and the resulting development are essential for meeting the 2050 emissions target.

- In the Energy sector, measures will provide better information and overcome institutional barriers that slow the adoption of cost-effective energy efficiency technologies. Enhanced energy efficiency programs will provide incentives for customers to purchase and install more efficient products and processes, and building and appliance standards will ensure that manufacturers and builders bring improved products to market.
- The Renewables Portfolio Standard (RPS) promotes multiple objectives, including diversifying the electricity supply. Increasing the RPS to 33 percent is designed to accelerate the transformation of the Electricity sector, including investment in the transmission infrastructure and system changes to allow integration of large quantities of intermittent wind and solar generation.
- The Million Solar Roofs Initiative uses incentives to transform the rooftop solar market by driving down costs over time.
- The Goods Movement program is primarily intended to achieve criteria and toxic air pollutant reductions but will provide important greenhouse gas benefits as well.
- Similar to the light duty vehicle greenhouse gas standards, the heavy duty and medium duty vehicle measures and the additional light duty vehicle efficiency measures aim to achieve cost-effective reductions of GHG emissions and save fuel.

Each of these complementary measures helps to position the California economy for the future by reducing the greenhouse gas intensity of products, processes, and activities. When combined with the absolute and declining emissions limit of the cap-and-trade program, these policies ensure that we cost-effectively achieve our greenhouse gas emissions goals and set ourselves on a path towards a clean low carbon future.

Figure 3 illustrates how the recommended emission reduction measures together put California on a path toward achieving the 2020 goal. The left hand column in Figure 3 shows total projected business as usual emissions in 2020, by sector (596 $MMTCO_2E$). The right hand column shows 2020 emissions after applying the Scoping Plan recommended reduction measures (422 $MMTCO_2E$). The measures that accomplish the needed reductions are listed in between the columns. As Figure 3 shows, there are a total of 27.3 $MMTCO_2E$ in reductions from uncapped sectors, and 146.7 $MMTCO_2E$ in reductions from capped sectors.

Figure 3: California Greenhouse Gas Emissions in 2020 and Recommended Reduction Measures



The recommended cap-and-trade program provides covered sources with the flexibility to pursue low cost reductions. It is important to recognize, however, that other recommended measures also provide compliance flexibility. As is often the case with ARB regulations, many of the measures establish performance standards and allow regulated entities to determine how best to achieve the required emission level. This approach rewards innovation and allows facilities to take advantage of the best way to meet the overarching environmental objective.

Table 3 lists the proposed measures that include compliance flexibility or market mechanisms. This flexibility ranges from the potential for tradable renewable energy credits in the Renewables Portfolio Standard to the incentives to encourage emission reductions in electricity and natural gas efficiency programs to the averaging, banking and trading mechanisms in the Pavley and Low Carbon Fuel Standard programs to a multi-sector cap-and-trade program.

Table 3: Measures With Flexible Market Compliance Features

Measure	Estimated Reductions
Additional Reductions from Capped Sectors	34.4
California Light-Duty Vehicle Greenhouse Gas Standards (Pavley I & II)	31.7
Renewables Portfolio Standard	21.3
Electricity Efficiency	15.2
Low Carbon Fuel Standard	15.0
Mitigation Fee on High GWP Gases	5.0
Natural Gas Efficiency	4.3
Goods Movement Systemwide Efficiency	3.5
Medium/Heavy Duty Vehicle Hybridization	0.5
Total	**130.9**

The recommended mix of measures builds on a strong foundation of previous action in California to address climate change and broader environmental issues. The program recommended here relies on implementing existing laws and regulations that were adopted to reduce greenhouse gas emissions and other policy goals; strengthening and expanding existing programs; implementing the discrete early actions adopted by the Board in 2007; and new measures developed during the Scoping Plan process itself.

The mix of measures recommended in this Plan provides a comprehensive approach to reduce emissions to achieve the 2020 target, and to initiate the transformations required to achieve the 2050 target. The cap-and-trade program and complementary measures will cover about 85 percent of greenhouse gas emissions throughout California's economy. ARB recognizes that due to several factors, including information discovered during regulatory development, technology maturity, and implementation challenges, actual reductions from individual measures aimed at achieving the 2020 target may be higher or lower than current estimates. The inclusion of many of these emissions within the cap-and-trade program, along with a margin of safety in the uncapped sectors, will help ensure that the 2020 target is met. The combination of approaches provides certainty that the overall program will meet the target despite some degree of uncertainty in the estimates for any individual measure. Additionally, by internalizing the cost of CO_2E emissions throughout the economy, the cap-and-trade program supports the complementary measures and provides further incentives for innovation and continuing emissions reductions from energy producers and consumers setting us on a path toward our 2050 goals.

Some emissions sources are not currently suitable for inclusion in the cap-and-trade program due to challenges associated with precise measurement, tracking or sector structure. For these emissions sources, ARB is including measures designed to focus on waste management, agriculture, forestry, and certain emissions of high GWP gases, a rapidly growing component of California's greenhouse gas emissions inventory.

California's economy is expected to continue to experience robust growth through 2020. Economic modeling, including evaluation of the effects on low-income Californians, shows that the measures included within this Scoping Plan can be implemented with a net positive effect on California's long-term economic growth. The evaluation of related public health and environmental benefits of the various measures also shows that implementation will result in not only reduced greenhouse gas emissions and improved public health, but also in a beneficial effect on California's environment. The results of these evaluations are presented in Chapter III.

AB 32 includes specific criteria that ARB must consider before adopting regulations for market-based compliance mechanisms to implement a greenhouse gas reduction program, and directs the Board, to the extent feasible, to design market-based compliance mechanisms to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants. In the development of regulations that contain market mechanisms, ARB will consider the economic, environmental and public health effects, and the evaluation of potential localized impacts. These results will be used to institute appropriate economic, environmental and public health safeguards.

ARB has also designed the recommendation to ensure that reductions will come from throughout the California economy. Transportation accounts for the largest share of California's greenhouse gas emissions. Accordingly, a large share of the reduction of greenhouse gas emissions from the recommended measures comes from this sector. Measures include the inclusion of transportation fuels in the cap-and-trade program, the Low Carbon Fuel Standard to reduce the carbon intensity of transportation fuels, enforcement of regulations that reduce greenhouse gas emissions from vehicles, and policies to reduce transportation emissions by changes in future land use patterns and community design as well as improvements in public transportation.

In the Energy sector, the recommended measures increase the amount of electricity from renewable energy sources, and improve the energy efficiency of industries, homes and buildings. The inclusion of these sectors and the Industrial sector in the cap-and-trade program provides further assurance that significant cost-effective reductions will be achieved from the sectors that contribute the greatest emissions. Additional energy production from renewable resources may also rely on measures suggested in the Agriculture, Water, and the Recycling and Waste Management Sectors.

Other sectors are also called upon to cut emissions. The cap-and-trade program covers industrial sources and natural gas use. The recommended measures would require industrial processes to examine how to lower their greenhouse gas emissions and be more energy efficient, and would require goods movement operations through California's ports to be more energy efficient. Other measures address waste management, agricultural and forestry practices, as well as the transport and treatment of water throughout the state. Finally, the recommended measures address ways to reduce or eliminate the emissions of high global warming potential gases that, on a per-ton basis, contribute to global warming at a level many times greater than carbon dioxide.

As the Scoping Plan is implemented, ARB and other agencies will coordinate with the Green Chemistry Initiative, particularly in the Green Building and Recycling/Waste sectors. Green Chemistry is a fundamentally new approach to environmental protection that emphasizes environmental protection at the design stage of product and manufacturing processes, rather than focusing on end-of-pipe or end-of-life activities, or a single environmental medium, such as air, water or soil. This new approach will reduce the use of harmful chemicals, generate less waste, use less energy, and, accordingly, will contribute toward California's greenhouse gas reduction goals.

A. The Role of State Government: Setting an Example

For many years California State government has successfully incorporated environmental principles in managing its resources and running its business. The Governor has directed State agencies to sharply reduce their building-related energy use and encouraged our State-run pensions to invest in energy efficient and clean technologies.[20] The State also has been active in procuring low-emission, alternative fuel vehicles in its large fleet.

While State government has already accomplished much to reduce its greenhouse gas emissions, it can and must do more. State agencies must lead by example by continuing to reduce their greenhouse gas emissions. Therefore, California State government has established a target of reducing its greenhouse gas emissions by a *minimum* of 30 percent below its estimated business-as-usual emissions by 2020 – approximately a 15 percent reduction from current levels.

As an owner-operator of key infrastructure, State government has the ability to ensure that the most advanced, cost-effective environmental performance requirements are used in the design, construction, and operation of State facilities. As a purchaser with significant market power, State government has the ability to demand that the products and services it procures contribute positively toward California's targets to reduce greenhouse gas emissions, such as through the efforts of Environmentally Preferable Purchasing. As an investor of more than $400 billion,[21] State government has the ability to prioritize low-carbon investments. With more than 350,000 employees, State government is uniquely situated to adopt and implement policies that give State workers the ability to decrease their individual carbon impact, including encouraging siting facilities within communities to enhance balance in jobs and housing, encouraging carpooling, biking, walking, telecommuting, the use of public transit, and the use of alternative work schedules.

---

[20]Governor Schwarzenegger signed Executive Order Executive Order S-20-04 on December 14, 2004. This Order contains a number of directives, including a set of aggressive goals for reducing state building energy use and requested the California Public Employees Retirement System (CalPERS) and the California State Teachers Retirement System (CalSTRS) to target resource-efficient buildings for real estate investments and commit funds toward clean, efficient and sustainable technologies.

[21] CalPERS and CalSTRS are the two largest pension systems in the nation with investments in excess of $400 billion as of August 2008.

Myriad opportunities exist for California State government to operate more efficiently. These opportunities will not only reduce greenhouse gas emissions but also will produce savings for California taxpayers. Initiatives now underway that will contribute to the State government reduction target include the Governor's Green Building Initiative and the Department of General Services' efforts to increase the number of fuel-efficient vehicles in the State fleet.

Major efforts to expand renewable energy use and divest from coal-fired power plants are currently underway. Together with energy conservation and efficiency strategies on water projects, roadways, parks, and bridges, these efforts all play major roles in reducing the State's greenhouse gas emissions. State agencies should review their travel practices and make greater use of teleconferencing and videoconferencing to reduce the need for business travel, particularly air travel.

State agencies are now examining their policies and operations to determine how they can reduce their greenhouse gas emissions. These findings will be instrumental as each cabinet-level agency registers with the California Climate Action Registry (CCAR) to record and report their individual carbon footprints. The Climate Action Team has created a new State Government Operations sub-group that will work closely with the agencies to review the results of their evaluations and the CCAR reports to determine how best to achieve the maximum reductions possible.

State agencies must take the lead in driving this low-carbon economy by reducing their own emissions, and also by serving as a catalyst for local government and private sector activity. New "Best Practices" implemented by State agencies can be transferred to other entities within California, the nation, and internationally. By increasing cooperation and coordination across organizational boundaries, State government will maximize the experience and contributions of each agency involved to achieve the 30 percent reduction of greenhouse gas emissions while growing the economy and protecting the environment.

State government's impact on emissions goes far beyond its own buildings, vehicles, projects, and employees. State government casts a sizable "carbon shadow"– that is, the climate change impact of legislative, executive, and financial actions of State agencies that affect Californians now and in the future. For example, the California Energy Commission (CEC) recently initiated a proceeding to consider how to align its permitting process with the State's greenhouse gas and renewable energy policy goals. ARB intends to work closely with the CEC during this proceeding. New power plants, both fossil-fuel fired and renewable generation, will be a critical part of the state's electricity mix in coming decades. The investments that are made in this new infrastructure in the next several years will become part of the backbone of the state's electricity supply for decades to come. This timely investigation will be a critical element of California's ability to meet the AB 32 emissions reduction target for 2020, the ambitious target set by the Governor for 2050, and also the specific goal of achieving 33 percent renewables in the state's electricity mix. The Governor's Office of Planning and Research and the Resources Agency are developing proposed amendments to the California Environmental Quality Act (CEQA) Guidelines to provide guidance on how to address greenhouse gases in CEQA documents. As required by SB 97 (Chapter 185, Statutes of 2007), the amended CEQA guidelines will be adopted by January 1, 2010.

In addition, agencies such as the California Labor and Workforce Development Agency, the Business, Transportation and Housing Agency and the newly created Green Collar Jobs Council (AB 3018, Chapter 312, Statutes of 2008) are dedicated to economic development, training, safety, labor relations, and employment development throughout the State. ARB will coordinate with the Council and also with other State agencies to address workforce needs and facilitate a smooth transition to California's emerging low-carbon economy that maximizes economic development and employment opportunities in California.

The State expends funds to provide services to California residents – from preserving our natural resources to building and maintaining infrastructure like roads, bridges and dams. California residents should reap all of the benefits of these projects, including any associated quantifiable and marketable reductions in greenhouse gas emissions. Because of this, California should retain ownership of these greenhouse gas emissions reductions and use them to promote the goals of AB 32 and other goals of the state.

California State government can also lead through example by aligning its efforts to reduce greenhouse gas emissions with efforts to protect and improve public health. As a new member of the Climate Action Team, the Department of Public Health will help ensure that measures to combat global warming also incorporate public health protection and improvement strategies. As discussed below, these and many other State leadership efforts can be built upon at the local level as well.

B. The Role of Local Government: Essential Partners

Local governments are essential partners in achieving California's goals to reduce greenhouse gas emissions. They have broad influence and, in some cases, exclusive authority over activities that contribute to significant direct and indirect greenhouse gas emissions through their planning and permitting processes, local ordinances, outreach and education efforts, and municipal operations. Many of the proposed measures to reduce greenhouse gas emissions rely on local government actions.

Over 120 California cities have already signed on to the U.S. Conference of Mayors Climate Protection Agreement. In addition, over 30 California cities and counties have committed to developing and implementing Climate Action Plans. Many local governments and related organizations have already begun educating Californians on the benefits of energy efficiency measures, public transportation, solar homes, and recycling. These communities have not only demonstrated courageous leadership in taking initiative to reduce greenhouse gas emissions, they are also reaping important co-benefits, including local economic benefits, more sustainable communities, and improved quality of life.

Land use planning and urban growth decisions are also areas where successful implementation of the Scoping Plan relies on local government. Local governments have primary authority to plan, zone, approve, and permit how and where land is developed to accommodate population growth and the changing needs of their jurisdictions. Decisions on how land is used will have large impacts on the greenhouse gas emissions that will result from the transportation, housing, industry, forestry, water, agriculture, electricity, and natural gas sectors.

To provide local governments guidance on how to inventory and report greenhouse gas emissions from government buildings, facilities, vehicles, wastewater and potable water treatment facilities, landfill and composting facilities, and other government operations, ARB recently adopted the Local Government Operations Protocol. ARB encourages local governments to use this protocol to track their progress in achieving reductions from municipal operations. ARB is also developing an additional protocol for community emissions. This protocol will go beyond just municipal operations and include emissions from the community as a whole, including residential and commercial activity. These local protocols will play a key role in ensuring that strategies that are developed and implemented at the local level, like urban forestry and greening projects, water and energy efficiency projects, and others, can be appropriately quantified and credited toward California's efforts to reduce greenhouse gas emissions.

In addition to tracking emissions using these protocols, ARB encourages local governments to adopt a reduction goal for municipal operations emissions and move toward establishing similar goals for community emissions that parallel the State commitment to reduce greenhouse gas emissions by approximately 15 percent from current levels by 2020. To consolidate climate action resources and aid local governments in their emission reduction efforts, the ARB is developing various tools and guidance for use by local governments, including the next generation of best practices, case studies, a calculator to help calculate local greenhouse gas emissions, and other decision support tools.

The recent passage of SB 375 (Steinberg, Chapter 728, Statutes of 2008) creates a process whereby local governments and other stakeholders work together within their region to achieve reduction of greenhouse gas emissions through integrated development patterns, improved transportation planning, and other transportation measures and policies. The implementation of regional transportation-related greenhouse gas emissions targets and SB 375 are discussed in more detail in Section C.

C. Emissions Reduction Measures

The Scoping Plan will build on California's successful history of balancing effective regulations with economic progress. Several types of measures have been recommended. The plan includes a California cap-and-trade program that will be integrated with a broader regional market to maximize cost-effective opportunities to achieve GHG emissions reductions. The plan also includes transformational measures that are designed to help pave the path toward California's clean energy future. For example, the Low Carbon Fuel

Standard (LCFS) is a performance standard with flexible compliance mechanisms that will incent the development of a diverse set of clean, low-carbon transportation fuel options. Similarly, the plan recognizes the importance of local and regional government leadership in ensuring that California's land use and transportation planning processes are designed to be consistent with efforts to achieve a clean energy future and to protect and enhance public health and safety.

The Scoping Plan also contains a number of targeted measures that are designed to overcome existing barriers to action such as lack of information, lack of coordination, or other regulatory and institutional factors. Energy efficiency is a classic example where cost-effective action often is not taken due to lack of complete information, relatively high initial costs, and mismatches between who pays for and who benefits from efficiency investments. These problems often mean that efficiency measures are not taken that would save money in the long term for small businesses, home owners and renters. While California has a long history of success in implementing regulations and programs to encourage energy efficiency, innovative methods to overcome these economic and information barriers are needed to provide the benefits of increased efficiency to more Californians and to meet our greenhouse gas emissions reduction goals.

Several of the recommended measures complement each other. For example, the LCFS will provide clean transportation fuel options. The Pavley performance standards help deploy vehicles that can use many of the low-carbon fuels, including advanced biofuels, electricity and hydrogen. The combined operation of both programs will make it more likely that more efficient, less polluting vehicles will use the cleanest possible fuels. In addition, both of these programs will benefit from ARB's zero-emission vehicle program, which focuses on deployment of plug-in battery-electric and fuel cell vehicles. All of these strategies are expandable beyond 2020, and are needed as vital components to reach the State's 2050 goal.

The cap-and-trade program creates an emissions limit or "cap" on the sectors responsible for the vast majority of California's greenhouse gas emissions and provides capped sources significant flexibility in how they collectively achieve the reductions necessary to meet the cap. The other measures in these capped sectors provide a clear path toward achieving reductions required by the cap, while simultaneously addressing market barriers and creating the low-carbon energy options needed to achieve our long term climate goals. In the design of the cap-and-trade program, ARB will also evaluate possible ways to include features that complement the other measures, such as consideration of allowance set-asides that could be used to help achieve or exceed the aggressive energy efficiency goals included in this Plan.

Both required measures and other cost-effective actions by capped sectors will contribute toward achievement of the cap. For example, increasing energy efficiency will reduce electricity demand, thereby reducing the need for utilities to submit allowances to comply with the cap-and-trade program. In this way, energy efficiency contributes to real reductions toward the cap. Expiration of existing utility long-term contracts with coal plants will reduce GHG emissions when such generation is replaced by renewable generation, coal with carbon sequestration, or natural gas generation, which emits less CO_2 per megawatt-hour.

Additionally, measures and other actions that result in reductions in energy demand 'downstream' of capped sectors will help achieve the cap. For example, the Pavley vehicle standards, building efficiency standards, and land use planning that contributes to reduced transportation fuel demand will all reduce emissions by reducing the demand for upstream energy production. These downstream entities will further benefit from these reductions by avoiding any costs that would be passed through from a cap-and-trade system.

Discrete Early Actions

In September 2007, ARB approved a list of nine Discrete Early Actions to reduce greenhouse gas emissions and is currently in the process of developing regulations and programs based on these measures. Regulations implementing the Discrete Early Action measures must be adopted and in effect by January 1, 2010 (HSC §38560.5 (b)). All the Discrete Early Actions are included in the recommended measures and are shown below in Table 4.

Table 4: Anticipated Board Consideration Dates for Discrete Early Actions

Discrete Early Action	Anticipated Board Consideration
Green Ports – Ship Electrification at Ports	December 2007 – Adopted
Reduction of High GWP Gases in Consumer Products	June 2008 – Adopted
SmartWay – Heavy-Duty Vehicle Greenhouse Gas Emission Reduction (Aerodynamic Efficiency)	December 2008
Reduction of Perfluorocarbons from Semiconductor Manufacturing	February 2009
Improved Landfill Gas Capture	January 2009
Reduction of HFC-134a from Do-It-Yourself Motor Vehicle Servicing	January 2009
SF_6 Reductions from the Non-Electric Sector	January 2009
Tire Inflation Program	March 2009
Low Carbon Fuel Standard	March 2009

The following sections describe the recommended measures in this Scoping Plan. Additional information about these measures is provided in Appendix C.

1. California Cap-and-Trade Program Linked to Western Climate Initiative Partner Jurisdictions

Implement a broad-based California cap-and-trade program to provide a firm limit on emissions. Link the California cap–and-trade program with other Western Climate Initiative Partner programs to create a regional market system to achieve greater environmental and economic benefits for California. Ensure California's program meets all applicable AB 32 requirements for market-based mechanisms.

California is working closely with other states and provinces in the Western Climate Initiative (WCI) to design a regional cap-and-trade program that can deliver reductions of greenhouse gas emissions throughout the region. ARB will develop a cap-and-trade program for California that will link with the programs in the other WCI Partner jurisdictions to create a regional cap-and-trade program. The WCI Partner jurisdictions released the program design document on September 23, 2008 (see Appendix D). ARB will continue to work with the WCI Partner jurisdictions to develop and implement the cap-and-trade program. ARB will also design the California program to meet the requirements of AB 32, including the need to consider any potential localized impacts and ensure that reductions are enforceable by the Board.

Based on the requirements of AB 32, regulations to implement the cap-and-trade program need to be developed by January 1, 2011, with the program beginning in 2012. This rule development schedule will be coordinated with the WCI timeline for developing a regional cap-and-trade program. Preliminary plans for this rulemaking are described later in this section.

A cap-and-trade program sets the total amount of greenhouse gas emissions allowable for facilities under the cap and allows covered sources, including producers and consumers of energy, to determine the least expensive strategies to comply. The emissions allowed under the cap will be denominated in metric tons of CO_2E. The currency will be in the form of allowances which the State will issue based upon the total emissions allowed under the cap during any specific compliance period. Emission allowances can be banked for future use, encouraging early reductions and reducing market volatility. The ability to trade allows facilities to adjust to changing conditions and take advantage of reduction opportunities when those opportunities are less expensive than buying additional emissions allowances.

Provisions could be made to allow a limited use of surplus reductions of greenhouse gas emissions that occur outside of the cap. These additional reductions are known as offsets and are discussed further below. In order to be used to meet a source's compliance obligation, offsets will be subject to stringent criteria and verification procedures to ensure their enforceability and consistency with AB 32 requirements.

Appendix C describes the fundamentals of a cap-and-trade program and program design elements. Appendix D contains the WCI Design Recommendations and related background documents.

California Cap-and-Trade Program

By providing a firm cap on 85 percent of the state's greenhouse gas emissions, the cap-and-trade regulatory program is an essential component of the overall plan to meet the 2020 target and provides a robust mechanism to achieve the additional reductions needed by 2050. To meet the emissions reduction target under AB 32, the limit on emissions allowed under the cap, plus emissions from uncapped sources, must be no greater than the 2020 emissions goal.

By setting a limit on the quantity of greenhouse gases emitted, a well-designed cap-and-trade program will complement other measures for entities within covered sectors. Additionally, starting a cap-and-trade program now will set us on a course to achieve further emissions cuts well beyond 2020 and ensure that California is primed to take advantage of opportunities for linking with other programs, including future federal and international efforts.

The proposed cap-and-trade measure phases in the following sectors:

Starting in the first compliance period (2012):

- In-state electrical generating facilities that emit over 25,000 metric tons CO_2E per year,[22] including imports not covered by a WCI Partner jurisdiction.
- Large industrial facilities that emit over 25,000 metric tons CO_2E per year, including high global warming potential gases.

Starting in the second compliance period (2015):

- Upstream treatment of industrial fuel combustion at facilities with emissions at or below 25,000 metric tons CO_2E per year, and all commercial and residential fuel combustion regulated where the fuel enters into commerce
- Transportation fuel combustion regulated where the fuel enters into commerce.

For some energy-intensive industrial sources such as cement, stringent requirements in California, either through inclusion in a cap-and-trade program or through source-specific regulation, have the potential to create a disadvantage for California facilities relative to out-of-state competitors unless those locations have similar requirements (e.g., through the WCI). If production shifts outside of California in order to operate without being subject to these requirements, emissions could remain unchanged or even increase. This is referred to as "leakage." AB 32 requires ARB to design measures to minimize leakage. Minimizing leakage will be a key consideration when developing the cap-and-trade regulation and the other AB 32 program measures.[23]

---

[22] Allowances will not be required for combustion emissions from carbon-neutral projects.

[23] The cement industry is an example of a sector that may be susceptible to this type of leakage, and the Draft Scoping Plan included consideration of a measure to institute an intensity standard at concrete batch plants that would consider this type of life-cycle emissions. ARB will evaluate whether this type of intensity standard could be incorporated into the cap-and-trade program or instituted as a complementary measure during the cap-and-trade rulemaking.

As shown in Table 5, the preliminary estimate of the cap on greenhouse gas emissions for sectors covered by the cap-and-trade program is 365 $MMTCO_2E$ in 2020, which covers about 85 percent of California's total greenhouse gas emissions.[24] Greenhouse gas emissions from most of the sectors covered by a cap-and-trade program will also be governed by other measures, including performance standards, efficiency programs, and direct regulations. These other measures will provide real reductions which will contribute reductions toward the cap.

In addition, ARB will work closely with the CPUC, CEC, and The California Independent System Operator to ensure that the cap-and-trade program works within the context of the State's energy policy and enables the reliable provision of electricity.

Table 5: Sector Responsibilities Under Cap-and-Trade Program
($MMTCO_2E$ in 2020)

Sector	Projected 2020 Business-as-Usual Emissions		Preliminary 2020 Emissions Limit under Cap-and-Trade Program
	By Sector	Total	
Transportation	225	512	365
Electricity	139		
Commercial and Residential	47		
Industry	101		

Linkage with the Western Climate Initiative Partner Jurisdictions

The WCI was formed in 2007. Members are California, Arizona, New Mexico, Oregon, Washington, Utah, and Montana, and the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec. The WCI Partner jurisdictions, including California, have adopted goals to reduce greenhouse gas emissions that, in total, reduce regional emissions to 15 percent below 2005 levels by 2020. This regional goal is approximately equal to California's goal of returning to 1990 levels by 2020. A cap-and-trade program is one element of the effort by the WCI Partner jurisdictions to identify, evaluate, and implement ways to reduce greenhouse gas emissions and achieve related co-benefits.

[24] The actual cap for the program will be established as part of the rulemaking process. The preliminary cap of 365 $MMTCO_2E$ in 2020 assumes that all of California's electricity imports would be covered under a California cap. Because a significant portion of California's imported electricity is from power plants located in other WCI Partner Jurisdictions, emissions from those sources could be included in the cap of the states within which the power plants are located. In establishing the California cap, ARB will need to consider the degree to which emissions from these sources are addressed as part of the WCI regional market.

The WCI Partner jurisdictions released their recommendation for the design of a regional cap-and-trade program in September 2008. This design document and the background paper that accompanied it are presented in Appendix D. These recommendations were developed collaboratively by the WCI Partner jurisdictions, including California, with a goal of achieving regional targets to reduce greenhouse gas emissions equitably and effectively. The WCI Partner jurisdictions' recommendations are generally consistent with the recommendations provided in June 2007 by the California Market Advisory Committee,[25] the recommendations provided to ARB by the California Public Utilities Commission and the California Energy Commission in March 2008,[26] and the proposed opinion released by the two Commissions in September 2008.[27]

Participating in a regional system has several advantages for California. The reduction of greenhouse gas emissions that can be achieved collectively by the WCI Partner jurisdictions are approximately double what can be achieved through a California-only program. The broad scope of a WCI-wide market will provide additional opportunities for reduction of emissions, therefore providing greater market liquidity and more stable carbon prices within the program. The regional system also significantly reduces the potential for leakage, which is a shift in economic and emissions activity out of California that could hurt the state's economy without reducing global greenhouse gas emissions. Harmonizing the approach and timing of California's requirements for reducing greenhouse gas emissions with other states and provinces in the region can encourage retention of local businesses in the state. Further, by creating a cost-effective regional market system, California and the other WCI Partner jurisdictions will continue to demonstrate leadership in preparation for future federal and international climate action.

To achieve the individual WCI Partner jurisdiction goals and the regional goal, each WCI Partner jurisdiction will have an allowance budget based on its goal that declines to 2020. For example, California's allowance budget will be based on the level of emissions needed to achieve the AB 32 target for 2020, as described above. Once California links with the other WCI Partner jurisdictions, allowances could be

---

[25] Recommendations of the Market Advisory Committee to the California Air Resources Board. *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. June 30, 2007. p. 19. http://www.climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF (accessed October 12, 2008) Cal/EPA The Market Advisory Committee (MAC) consisted of a consortium of economists, policy makers, academics, government representatives, and environmental advocates who came together through the auspices of CalEPA, pursuant to Executive Order S-20-06 from Governor Schwarzenegger.

[26] Joint Agency Decision of the CEC and the CPUC. *Final Adopted Interim Decision on Basic Greenhouse Gas Regulatory Framework for Electricity and Natural Gas Sectors*, March 13, 2008. Document number CEC-100-2008-002-F. http://www.energy.ca.gov/2008publications/CEC-100-2008-002/CEC-100-2008-002-F.PDF (accessed October 12, 2008)

[27] Joint Agency proposed final opinion of the CEC and the CPUC. *Proposed Final Opinion on Greenhouse Gas Regulatory Strategies*. Published September 12, 2008 and to be considered for adoption on October 16, 2008 by the CEC and the CPUC. Document Number CEC-100-2008-007-D http://www.energy.ca.gov/ghg_emissions/index.html (accessed October 12, 2008)

traded across state and provincial boundaries. As a result of trading, emissions in a state may vary from its allowance budget, although total regional emissions will not exceed the regional cap.

The overall number of allowances issued in a given year by the WCI Partner jurisdictions will set a limit on emissions from sectors covered by the program for the region. Details of distribution of allowances will be established by each partner within the general guidelines set forth in the WCI program design framework. The WCI Partner jurisdictions have agreed to consider standardizing allowance distribution across specific sectors if necessary to address competitiveness issues. In addition, the WCI Partner jurisdictions have agreed to phase in regionally coordinated auctions of allowances, with a minimum percentage of allowances auctioned in each period starting with 10 percent in the first compliance period and increasing to 25 percent in 2020. WCI partners aspire to reach higher auction percentages over time, possibly to 100 percent. Under the program design, each WCI Partner jurisdiction, including California, can auction a greater portion of its allowance budget in any compliance period. The distribution of California's allowances will be determined during the cap-and-trade rulemaking process, as discussed below.

The WCI Partner jurisdictions are also proposing the use of an allowance reserve price for the first 5 percent of the auctioned allowances in the regional cap. A reserve price will help to ensure that the cap is set at a level that will motivate real emissions reductions and may provide an opportunity for the regional cap-and-trade program to provide reductions that exceed the regional target.

A regional coordinated cap-and-trade program with strong reporting and enforcement rules will provide a high degree of certainty that emissions will not exceed targeted levels and that leakage will not occur.

Federal Action

A cap-and-trade program is expected to be a significant element in any future federal action taken to reduce greenhouse gas emissions. ARB's efforts to design a broad cap-and-trade system that works in concert with sector- or source-related measures and meets the requirements of AB 32 can serve as a model for a federal program. An effective, enforceable regional cap-and-trade program can promote the type of federal legislation needed to meet the pressing challenge of climate change. In the event that California businesses, organizations, or individuals hold regional allowances when a federal system is implemented, California will work to ensure that those allowances continue to have value, either in a continuing regional program or within the federal program.

Cap-and-Trade Rulemaking

To implement the cap-and-trade program, ARB will embark on regulatory development that includes extensive and broad-based public participation. Major program design elements will include setting an emissions cap in conjunction with the

WCI Partner jurisdictions, determining the method of distributing both allowances and revenues raised through auctions, and establishing the rules for the use of offsets. ARB will continue to work with all affected stakeholders, State and local agencies, and our WCI partners to create a robust regional market system.

After adoption of the Scoping Plan, ARB will establish a formal structure to elicit ongoing participation in the rulemaking process from a wide range of affected stakeholders. While the process will be open to involvement by all interested parties, ARB anticipates creation of a series of focused working groups that include participation by representatives of the regulated community, environmental and community advocates and other public interest groups, prominent academics with expertise in cap-and-trade issues and new technology development, local air pollution control districts, stakeholders in the WCI, and other State agencies with existing authority for regulating capped sectors.

This process will integrate economic and administrative design considerations and include consideration of environmental and public health issues. ARB will convene a series of technical workshops to examine mechanisms to address the concerns related to the cap-and-trade program raised by the Environmental Justice Advisory Committee and other stakeholders. The first workshop will explore cap-and-trade program design options that could provide incentives to maximize additional environmental and economic benefits, and to analyze the proposed program to prevent increases in emissions of toxic air contaminants or criteria pollutants through the design and architecture of the program itself. Similar technical workshops will focus on issues related to offsets and the WCI proposal.

Allowances and Revenues

Emission allowances represent a significant economic value whether they are freely allocated or sold through auction. Section E includes a preliminary discussion of some of the options that have been suggested for use of allowance value or revenues. ARB will evaluate the possible uses of allowances or revenues as part of the rulemaking process. One approach would be to dedicate a portion of the allowances for such purposes as rewarding early actions to reduce emissions, providing incentives for local governments and others to promote energy efficiency, better land use planning, and other reduction strategies, and targeting projects to reduce emissions in low-income or disadvantaged communities. This type of dedicated use of allowances is typically referred to as an allowance ‘set-aside.’

The California Public Utilities Commission and the California Energy Commission addressed the question of allocation and auction of allowances in their joint proceeding on implementation of AB 32 for the Electricity and Natural Gas sectors. They have recently released a proposed opinion that recommends to ARB a transition to 100 percent auction for the Electricity sector by 2016.[28] The CPUC and CEC included in their draft opinion the recommendation that all auction revenues be used for purposes related to AB 32, and all revenue from allowances allocated to the Electricity sector and received by retail providers would be used for the benefit of the Electricity sector to support investments in renewable energy, efficiency, new energy technology, infrastructure, customer bill relief, and other similar programs.

The Market Advisory Committee also recommended the eventual transition to full auction within the cap-and-trade program, noting that a system in which California ultimately auctions all of its emission allowances is consistent with fundamental objectives of cost-effectiveness, fairness and simplicity.[29] ARB agrees that the transition to a 100 percent auction, with auction revenue going to further the policy objectives of California's climate change program, is a worthwhile goal. ARB expects that California will auction significantly more than the WCI minimum levels and will transition to 100 percent auction. However a broad set of factors must be considered in evaluating the potential timing of a transition to a full auction including competiveness, potential for emissions leakage, the effect on regulated vs. unregulated industrial sectors, the overall impact on consumers, and the strategic use of auction revenues.

Allowance allocation and revenue use decisions can greatly affect the equity of a cap-and-trade system. Addressing both these issues will be a major part of the rulemaking process. ARB will seek input from a broad range of experts in an open public process regarding the options for allocation and revenue use under consideration by ARB and the WCI Partner jurisdictions. This process will evaluate various mechanisms ARB is considering for allowance distribution and potential uses of allowance value, including the recommendations offered by CPUC and CEC. Issues to be considered will include the appropriate timing and structure of a transition to full auction of allowances, the potential need to harmonize the allocation process regionally for certain sectors subject to inter-state competition, and equity across the various sectors here in California.

Offsets

Individual projects can be developed to achieve the reduction of emissions from activities not otherwise regulated, covered under an emissions cap, or resulting from government incentives. These projects can generate "offsets," i.e., verifiable reductions of emissions whose ownership can be transferred to others. The cap-and-trade rulemaking will establish appropriate rules for use of offsets. As required by

---

[28] Op. Cit. The proposed opinion has not yet been voted on by either the CPUC or the CEC. The Commissions are expected to vote on this proposed opinion before the December Board meeting when the Proposed Scoping Plan will be considered for approval.

[29] Recommendations of the Market Advisory Committee to the California Air Resources Board. *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*. June 30, 2007. p. 55. http://www.climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF (accessed October 12, 2008)

AB 32, any reduction of greenhouse gas emissions used for compliance purposes must be real, permanent, quantifiable, verifiable, enforceable, and additional (HSC §38562(d)(1) and (2)). Offsets used to meet regulatory requirements must be quantified according to Board-adopted methodologies, and ARB must adopt a regulation to verify and enforce the reductions (HSC §38571). The criteria developed will ensure that the reductions are quantified accurately and are not double-counted within the system.

Offsets can provide regulated entities a source of low-cost emissions reductions. Reductions from compliance offset projects must be quantified using rigorous measurement and enforcement protocols that provide a basis to determine whether the reductions are also additional, i.e., beyond what would have happened in the absence of the offset project. Establishing that reductions are additional is one of the major challenges in establishing the validity of particular offset projects. Once a project can quantify emissions using an approved methodology, the reductions of emissions must be verified to ensure that reductions actually occurred.

While some offsets provide benefits, allowing unlimited offsets would reduce the amount of reductions of greenhouse gas emissions occurring within the sectors covered by the cap-and-trade program. This could reduce the local economic, environmental and public health co-benefits and delay the transition to low-carbon energy systems within the capped sectors that will be necessary to meet our long term climate goals. The limit on the use of offsets and allowances from other systems within the WCI Partner jurisdiction program design assures that a majority of the emissions reductions required from 2012 to 2020 occur at entities and facilities covered by the cap and trade program. Consequently, the use of offsets and allowances from other systems are limited to no more than 49 percent of the required reduction of emissions. This quantitative limit will help provide balance between the need to achieve meaningful emissions reductions from capped sources with the need to provide sources within capped sectors the opportunity for low-cost reduction opportunities that offsets can provide. The WCI offset program may incorporate flexibility to use offsets and non-WCI allowances across the three compliance periods, which each WCI Partner jurisdiction could use at its discretion. ARB will apply the limit on offsets that is within its jurisdiction, such that the allowable offsets in each compliance period is less than half of the emissions reductions expected from capped sectors in that compliance period. Each WCI Partner jurisdiction may choose to adopt a more stringent limit on the use of offsets and non-WCI allowances.

Offsets can also encourage the spread of clean, low carbon technologies outside California. High quality offset projects located outside the state can help lower the compliance costs for regulated entities in California, while reducing greenhouse gas emissions in areas that would otherwise lack the resources needed to do so. International projects may also have significant environmental, economic and social benefits. Projects in the Mexican border region may be of particular interest, considering the opportunity to realize considerable co-benefits on both sides of the border. The Governor has recently signed a Memorandum of Understanding with the six Mexican border states that calls for cooperation on the development of project protocols for Mexican greenhouse gas emissions reduction projects.[30] Additionally, defining project types related to imported commodities (such as cement) would enable California to provide incentives to reduce emissions associated with products that are imported into the state for our consumption.

California is committed to working at the international level to reduce greenhouse gas emissions globally and finding ways to support the adoption of low-carbon technologies and sustainable development in the developing world. ARB will work with WCI Partner jurisdictions and within the rulemaking process to establish an offsets program without geographic restrictions that includes sufficiently stringent criteria for creating offset credits to ensure the overall environmental integrity of the program.

One concept being evaluated for accepting offsets from the developing world is to limit offsets to those jurisdictions that demonstrate performance in reducing emissions and/or achieving greenhouse gas intensity targets in certain carbon intensive sectors (e.g., cement), or in reducing emissions or enhancing sequestration through eligible forest carbon activities in accordance with appropriate national or sub-national accounting frameworks. This could be achieved through an agreement to work jointly to develop minimum performance standards or sectoral benchmarks, backed by appropriate monitoring and accounting frameworks. Such agreements would encourage early action in developing countries toward binding commitments, and could also reduce concerns about competitiveness and risks associated with carbon leakage.

2. California Light-Duty Vehicle Greenhouse Gas Standards

Implement adopted Pavley standards and planned second phase of the program. Align zero-emission vehicle, alternative and renewable fuel and vehicle technology programs with long-term climate change goals.

Passenger vehicles are responsible for almost 30 percent of California's greenhouse gas emissions. To address these emissions, ARB is proposing a comprehensive three-prong strategy – reducing greenhouse gas emissions from vehicles, reducing the carbon content of the fuel these vehicles burn, and reducing the miles these vehicles travel. Transportation fuels and regional transportation-related greenhouse gas targets are discussed later in the recommendations.

There are a number of efforts intended to reduce greenhouse gas emissions from California's passenger vehicles, including the Pavley greenhouse gas vehicle

[30] Memorandum of Understanding on Environmental Cooperation between the California Environmental Protection Agency, the California Department of Food and Agriculture and the California Resources Agency of the State of California, United States of America and the Ministry of Environment and Natural Resources of the United Mexican States. February 13, 2008. http://gov.ca.gov/pdf/press/021308_MOU_English.pdf (accessed October 12, 2008)

standards to achieve near-term emission reductions, the zero-emission vehicle (ZEV) program to transform the future vehicle fleet, and the Alternative and Renewable Fuel and Vehicle Technology Program created by AB 118 (Núñez, Chapter 750, Statutes of 2007).

Pavley Greenhouse Gas Vehicle Standards

AB 1493 (Pavley, Chapter 200, Statutes of 2002) directed ARB to adopt vehicle standards that lowered greenhouse gas emissions to the maximum extent technologically feasible, beginning with the 2009 model year. ARB adopted regulations in 2004 and applied to the U.S. Environmental Protection Agency (U.S. EPA) for a waiver under the federal Clean Air Act to implement the regulation. The Pavley regulations incorporate both performance standards and market-based compliance mechanisms. To obtain additional reductions from the light duty fleet, ARB plans to adopt a second, more stringent, phase of the Pavley regulations. Table 6 summarizes the estimated reduction of emissions for the Pavley regulations. In addition to delivering greenhouse gas emissions reductions, the standards will save money for Californians who purchase vehicles that comply with the Pavley standards – an estimated average of $30 each month in avoided fuel costs.

To date, 13 other states have adopted California's existing greenhouse gas standards for vehicles. Under federal law, California is the only state allowed to adopt its own vehicle standards (though other states are permitted to adopt California's more rigorous standards), but California cannot implement the regulations until U.S. EPA grants an administrative waiver. In December 2007, U.S. EPA denied California's waiver request to implement the Pavley regulations. California and others are challenging that denial in Federal court. The regulations have also been challenged by the automakers in federal courts, although to date, those challenges have been unsuccessful.

ARB is evaluating the use of feebates as a measure to achieve additional reductions from the mobile source sector, either as a backstop to the Pavley regulation if the regulation cannot be implemented, or as a supplement to Pavley if the waiver is approved and the regulation takes effect. AB 32 specifically states that if the Pavley regulations do not remain in effect, ARB shall implement alternative regulations to control mobile sources to achieve equivalent or greater reductions of greenhouse gas emissions (HSC §38590). ARB is currently evaluating the use of a feebate program as the mechanism to secure these reductions. A feebate regulation would combine a rebate program for low-emitting vehicles with a fee program for high-emitting vehicles. This program would be designed in a way to generate equivalent or greater cumulative reductions of greenhouse gas emissions compared to what would have been achieved under the Pavley regulations. ARB would also evaluate the potential to expand the program to include additional vehicle classes not currently included in the Pavley program for further greenhouse gas benefits.

If the U.S. EPA grants California's request for a waiver to proceed with implementation of the Pavley regulations, we will analyze the potential for pursuing a feebate program that could complement the Pavley regulations and achieve additional reductions of greenhouse gas emissions.

Zero-Emission Vehicle Program

The Zero Emission Vehicle (ZEV) program will play an important role in helping California meet its 2020 and 2050 greenhouse gas emissions reduction requirements. Through 2012, the program requires placement of hundreds of ZEVs (including hydrogen fuel cell and battery electric vehicles) and thousands of near-zero emission vehicles (plug-in hybrids, conventional hybrids, compressed natural gas vehicles). In the mid-term (2012-2015), the program will require placement of increasing numbers of ZEVs and near-zero emission vehicles in California. In 2009, the Board will consider a proposal that is currently being developed to ensure that the ZEV program is optimally designed to help the State meet its 2020 target and put us on the path to meeting our 2050 target of an 80 percent reduction in greenhouse gas emissions.

It is important to note that while the use of both battery-powered electric vehicles and plug-in hybrids (which can be plugged in to recharge batteries) is not expected to increase electricity demand in the near term, over the longer term these technologies could result in meaningful new electricity demand. However, the expected increased electricity demand is likely to be met by off peak vehicle battery charging (i.e., overnight) to provide a means of load leveling and other possible benefits.[31]

Air Quality Improvement Program/Alternative and Renewable Fuel and Vehicle Technology Program

Under AB 118 (Núñez, Chapter 750, Statutes of 2007), ARB is administering the Air Quality Improvement Program, which provides approximately $50 million per year for grants to fund clean vehicle/equipment projects and research on the air quality impacts of alternative fuels and advanced technology vehicles.

AB 118 also created the Alternative and Renewable Fuel and Vehicle Technology Program and authorized CEC to spend up to $120 million per year for over seven years (from 2008-2015) to develop, demonstrate, and deploy innovative technologies to transform California’s fuel and vehicle types. This program creates the opportunities for investment in technologies and fuels that will help meet the Low Carbon Fuel Standard, the AB 1007 (Pavley, Chapter 371, Statutes of 2005) goal of increasing alternative fuels, the AB 32 goal of reducing greenhouse gas emissions to 1990 levels by 2020, and the State’s overall goal of reducing greenhouse gas emissions 80 percent below 1990 levels by 2050. CEC and ARB are coordinating closely in the implementation of AB 118. In the long-term, programs to reduce greenhouse gas emissions from cars would reduce highway funds because less fuel would be sold, reducing tax revenue. In coordination with other State agencies, ARB

[31] There is also a potential for battery-electric and hybrid vehicles (both plug-in and traditional hybrid-electric) to be used in the future to provide electricity back into the electricity grid during times of especially high demand (peak periods).

will continue to evaluate the potential impacts of these shifts and identify potential solutions.

Table 6: California Light-Duty Vehicle Greenhouse Gas Standards Recommendation
(MMTCO2E in 2020)

Measure No.	Measure Description	Reductions
T-1	Pavley I and II – Light-Duty Vehicle Greenhouse Gas Standards	31.7
	Total	**31.7**

3. Energy Efficiency

Maximize energy efficiency building and appliance standards, and pursue additional efficiency efforts including new technologies, and new policy and implementation mechanisms. Pursue comparable investment in energy efficiency from all retail providers of electricity in California (including both investor-owned and publicly-owned utilities).

Energy-efficiency measures for both electricity and natural gas can reduce greenhouse gas emissions significantly. In 2003, the CPUC and CEC adopted an Energy Action Plan that prioritized resources for meeting California's future energy needs, with energy efficiency being first in the "loading order," or highest priority. Since then, this policy goal has been codified into statute through legislation that requires electric utilities to meet their resource needs first with energy efficiency.[32]

This measure would set new targets for statewide annual energy demand reductions of 32,000 gigawatt hours and 800 million therms from business as usual[33] – enough to power more than 5 million homes, or replace the need to build about ten new large power plants (500 megawatts each). These targets represent a higher goal than existing efficiency targets established by CPUC for the investor-owned utilities due to the inclusion of innovative strategies above traditional utility programs. Achieving the State's energy efficiency targets will require coordinated efforts from the State, the federal government, energy companies and customers. ARB will work with CEC and CPUC to facilitate these partnerships. A number of these measures also have the potential to deliver significant economic benefits to California consumers, including low-income households and small businesses. California's energy efficiency programs for buildings and appliances have generated more than $50 billion in

[32] SB 1037 (Kehoe, Chapter 366, Statutes of 2005) and AB 2021 (Levine, Chapter 734, Statutes of 2006) directed electricity corporations subject to CPUC's authority and publicly-owned electricity utilities to first meet their unmet resource needs through all available energy efficiency and demand response resources that are cost effective, reliable and feasible.

[33] The savings targeted here are additional to savings currently assumed to be incorporated in CEC's 2007 demand forecasts. However, CEC has initiated a public process to better determine the quantity of energy savings from standards, utility programs, and market effects that are embedded in the baseline demand forecast.

savings over the past three decades. Tables 7 and 8 summarize the reduction of greenhouse gas emissions.

Efficiency

Achieving the energy efficiency target will require redoubled efforts to target industrial, agricultural, commercial, and residential end-use sectors, comprised of both innovative new initiatives that have been embraced by CEC's energy policy reports and CPUC's long-term strategic plan, and improvements to California's traditional approaches of improved building standards and utility programs.

High-efficiency distributed generation applications like fuel cell technologies can also play an important role in helping the State meet its requirements for reduction of greenhouse gas emissions. Key energy efficiency strategies, grouped by type, include:

Cross-cutting Strategy for Buildings

- "Zero Net Energy" buildings[34]

Codes and Standards Strategies

- More stringent building codes and appliance efficiency standards
- Broader standards for new types of appliances and for water efficiency
- Improved compliance and enforcement of existing standards
- Voluntary efficiency and green building targets beyond mandatory codes

Strategies for Existing Buildings

- Voluntary and mandatory whole-building retrofits for existing buildings
- Innovative financing to overcome first-cost and split incentives for energy efficiency, on-site, renewables, and high efficiency distributed generation

Existing and Improved Utility Programs

- More aggressive utility programs to achieve long-term savings

Other Needed Strategies

- Water system and water use efficiency and conservation measures
- Local government programs that lead by example and tap into local authority over planning, development, and code compliance
- Additional industrial and agricultural efficiency initiatives
- Providing real time energy information technologies to help consumers conserve and optimize energy performance

With the support of key State agencies, utilities, local governments and others, the CPUC has recently adopted the *California Long Term Energy Efficiency Strategic*

[34] Zero net energy refers to building energy use over the course of a typical year. When the building is producing more electricity than it needs, it exports its surplus to the grid. When the building requires more electricity than is being produced on-site, it draws from the grid. Generally, when constructing a ZNE building, energy efficiency measures can result in up to 70% savings relative to existing building practices, which then allows for renewables to meet the remaining load.

Plan.[35] Released September 2008, this Plan sets forth a set of strategies toward maximizing the achievement of cost-effective energy efficiency in California's Electricity and Natural Gas sectors between 2009 and 2020, and beyond. Its recommendations are the result of a year-long collaboration by energy experts, utilities, businesses, consumer groups, and governmental organizations in California, throughout the west, nationally and internationally.

For many of the above goals and others, the Strategic Plan discusses practical implementation strategies, detailing necessary partnerships among the state, its utilities, the private sector, and other market players and timelines for near-term, mid-term and long-term success. While the Strategic Plan is the most current and innovative summary of energy efficiency strategies needed to meet State goals, additional planning and new strategies will likely be needed, both to achieve the 2020 emissions reduction goals and to set the State on a trajectory toward 2050.

Other innovative approaches could also be used to motivate private investment in efficiency improvements. One example that will be evaluated during the development of the cap-and-trade program is the creation of a mechanism to make allowances available within the program to provide incentives for local governments, third party providers, or others to pursue projects to reduce greenhouse gas emissions, including the bundling of energy efficiency improvements for small businesses or in targeted communities.

Solar Water Heating

Solar water heating systems offer a potential for natural gas savings in California. A solar water heating system offsets the use of natural gas by using the sun to heat water, typically reducing the need for conventional water heating by about two-thirds. Successful implementation of the zero net energy target for new buildings will require significant growth in California's solar water heating system manufacturing and installation industry. The State has initiated a program to move toward a self sustaining solar water heater industry. The Solar Hot Water and Efficiency Act of 2007 (SHWEA) authorized a ten year, $250-million incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017.[36]

Combined Heat and Power

Combined heat and power (CHP), also referred to as cogeneration, produces electricity and useful thermal energy in an integrated system. The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants. This measure sets a target of an additional

---

[35] California Public Utilities Commission. *California Long Term Energy Efficiency Strategic Plan.* September 2008. http://www.californiaenergyefficiency.com/docs/EEStrategicPlan.pdf (accessed October 12, 2008).

[36] Established under Assembly Bill 1470 (Huffman, Chapter 536, Statues of 2007).

4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 GWh of demand from other power generation sources.[37]

California has supported CHP for many years, but market and other barriers continue to keep CHP from reaching its full market potential. Increasing the deployment of efficient CHP will require a multi-pronged approach that includes addressing significant barriers and instituting incentives or mandates where appropriate. These approaches could include such options as utility-provided incentive payments, the creation of a CHP portfolio standard, transmission and distribution support payments, or the use of feed-in tariffs.

Table 7: Energy Efficiency Recommendation - Electricity
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-1	Energy Efficiency (32,000 GWh of Reduced Demand) • Increased Utility Energy Efficiency Programs • More Stringent Building & Appliance Standards • Additional Efficiency and Conservation Programs	15.2
E-2	Increase Combined Heat and Power Use by 30,000 GWh	6.7
	Total	**21.9**

Table 8: Energy Efficiency Recommendation - Commercial and Residential
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
CR-1	Energy Efficiency (800 Million Therms Reduced Consumption) • Utility Energy Efficiency Programs • Building and Appliance Standards • Additional Efficiency and Conservation Programs	4.3
CR-2	Solar Water Heating (AB 1470 goal)	0.1
	Total	**4.4**

4. Renewables Portfolio Standard

Achieve 33 percent renewable energy mix statewide.

CEC estimates that about 12 percent of California's retail electric load is currently met with renewable resources. Renewable energy includes (but is not limited to) wind, solar, geothermal, small hydroelectric, biomass, anaerobic digestion, and landfill gas. California's current Renewables Portfolio Standard (RPS) is intended to

[37] Accounting for avoided transmission line losses of seven percent, this amount of CHP would actually displace 32,000 GWh from the grid.

increase that share to 20 percent by 2010. Increased use of renewables will decrease California's reliance on fossil fuels, thus reducing emissions of greenhouse gases from the Electricity sector. Based on Governor Schwarzenegger's call for a statewide 33 percent RPS, the Plan anticipates that California will have 33 percent of its electricity provided by renewable resources by 2020, and includes the reduction of greenhouse gas emissions based on this level.

Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) obligates the investor-owned utilities (IOUs) to increase the share of renewables in their electricity portfolios to 20 percent by 2010. Meanwhile, the publicly-owned utilities (POUs) are encouraged but not required to meet the same RPS. The governing boards of the state's three largest POUs, the Los Angeles Department of Water and Power (LADWP), the Sacramento Municipal Utility District (SMUD), and the Imperial Irrigation District (IID), have adopted policies to achieve 20 percent renewables by 2010 or 2011. LADWP and IID have established targets of 35 and 30 percent, respectively, by 2020.

In 2005, CEC and CPUC committed in the Energy Action Plan II to "evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities." The proposed opinion in the CPUC/CEC joint proceeding lends strong support for obtaining 33 percent of California's electricity from renewables, and states the two Commissions' belief that this target is achievable if the State commits to significant investments in transmission infrastructure and key program augmentation. As with the energy efficiency target, achieving the 33 percent goal will require broad-based participation from many parties and the removal of barriers. CEC, CPUC, California Independent System Operator (CAISO), and ARB are working with California utilities and other stakeholders to formally establish and meet this goal.

A key prerequisite to reaching a target of 33 percent renewables will be to provide sufficient electric transmission lines to renewable resource zones and system changes to allow integration of large quantities of intermittent wind and solar generation. The Renewable Energy Transmission Initiative (RETI) is a broad collaborative of State agencies, utilities, the environmental community, and renewable generation developers that are working cooperatively to identify and prioritize renewable generation zones and associated transmission projects. Although biomass, geothermal, and small-scale hydroelectric generation can provide steady baseload power, other renewable generation is intermittent (wind) or varies over time (solar). Therefore, integration of intermittent generation into the electricity system will require grid improvements so that fluctuations in power availability can be accommodated. Improved communications technology, automated demand response, electric sub-station improvements and other modern technologies must be implemented both to facilitate intermittent renewables, and to improve grid reliability.

Another key action that may help to achieve the renewable energy goals is to reduce the complexity and cost faced by small renewable developers in contracting with utilities to supply renewable generation. This is particularly important for projects offering below 20 megawatts of generation capacity. One such option may be a feed-in tariff for all RPS-eligible renewable energy facilities up to 20 megawatts in size. This mechanism was recommended in CEC's 2007 Integrated Energy Policy Report. Such a tariff, set at an appropriate level, could benefit small-scale facilities by allowing them to be brought into the electricity grid more rapidly.

For the purposes of calculating the reduction of greenhouse gas emissions in this Scoping Plan, ARB is counting emissions avoided by increasing the percentage of renewables in California's electricity mix from the current level of 12 percent to the 33 percent goal, as shown in Table 9.

Table 9: Renewables Portfolio Standard Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-3	Achieve a 33% renewables mix by 2020	21.3
	Total	**21.3**

5. Low Carbon Fuel Standard

Develop and adopt the Low Carbon Fuel Standard.

Because transportation is the largest single source of greenhouse gas emissions in California, the State is taking an integrated approach to reducing emissions from this sector. Beyond including vehicle efficiency improvements and lowering vehicle miles traveled, the State is proposing to reduce the carbon intensity of transportation fuels consumed in California.

To reduce the carbon intensity of transportation fuels, ARB is developing a Low Carbon Fuel Standard (LCFS), which would reduce the carbon intensity of California's transportation fuels by at least ten percent by 2020 as called for by Governor Schwarzenegger in Executive Order S-01-07.

LCFS will incorporate compliance mechanisms that provide flexibility to fuel providers in how they meet the requirements to reduce greenhouse gas emissions. The LCFS will examine the full fuel cycle impacts of transportation fuels and ARB will work to design the regulation in a way that most effectively addresses the issues raised by the Environmental Justice Advisory Committee and other stakeholders. ARB identified the LCFS as a Discrete Early Action item, and is developing a regulation for Board consideration in March 2009. A 10 percent reduction in the intensity of transportation fuels is expected to equate to a reduction of 16.5 $MMTCO_2E$ in 2020. However, in order to account for possible overlap of benefits between LCFS and the Pavley greenhouse gas standards, ARB has discounted the contribution of LCFS to 15 $MMTCO_2E$.

Table 10: Low Carbon Fuel Standard Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
T-2	Low Carbon Fuel Standard (Discrete Early Action)	15
	Total	**15**

6. Regional Transportation-Related Greenhouse Gas Targets

Develop regional greenhouse gas emissions reduction targets for passenger vehicles.

Establishment of Regional Targets

On September 30, 2008, Governor Arnold Schwarzenegger signed Senate Bill 375 (Steinberg) which establishes mechanisms for the development of regional targets for reducing passenger vehicle greenhouse gas emissions. Through the SB 375 process, regions will work to integrate development patterns and the transportation network in a way that achieves the reduction of greenhouse gas emissions while meeting housing needs and other regional planning objectives. This new law reflects the importance of achieving significant additional reductions of greenhouse gas emissions from changed land use patterns and improved transportation to help achieve the goals of AB 32.

SB 375 requires ARB to develop, in consultation with metropolitan planning organizations (MPOs), passenger vehicle greenhouse gas emissions reduction targets for 2020 and 2035 by September 30, 2010. It sets forth a collaborative process to establish these targets, including the appointment by ARB of a Regional Targets Advisory Committee to recommend factors to be considered and methodologies for setting greenhouse gas emissions reduction targets. SB 375 also provides incentives – relief from certain California Environmental Quality Act (CEQA) requirements for development projects that are consistent with regional plans that achieve the targets.

Reaching the Targets

Transportation planning is done on a regional level in major urban areas, through the Metropolitan Planning Organizations. These MPOs are required by the federal government to prepare regional transportation plans (RTPs) in order to receive federal transportation dollars. These plans must reflect the land uses called out in city and county general plans. Regional planning efforts provide an opportunity for community residents to help select future growth scenarios that lead to more sustainable and energy efficient communities. Such plans should be developed through an extensive public process to provide for local accountability.

SB 375 requires MPOs to prepare a sustainable communities strategy to reach the regional target provided by ARB. MPOs would use the sustainable communities strategy for the land use pattern underlying the region's transportation plan. If the strategy does not meet the target, the MPO must document the impediments and show how the target could be met with an alternative planning strategy. The CEQA relief would be provided to those projects that are consistent with either the sustainable communities strategy or alternative planning strategy, whichever meets the target.

Many regions in California have conducted comprehensive scenario planning, called Blueprint planning, that engages a broad set of stakeholders at the local level on the impacts of land use and transportation choices. The State has allocated resources to initiate or augment existing Blueprint efforts of MPOs. These efforts focus on fostering efficient land use patterns that not only reduce vehicle travel but also accommodate an adequate supply of housing, reduce impacts on valuable habitat and productive farmland, increase resource use efficiency, and promote a prosperous regional economy. Blueprint planning can play an important role in the SB 375 process by helping inform target-setting efforts and building strong sustainable communities strategies.

Local governments will play a significant role in the regional planning process to reach passenger vehicle greenhouse gas emissions reduction targets. Local governments have the ability to directly influence both the siting and design of new residential and commercial developments in a way that reduces greenhouse gases associated with vehicle travel, as well as energy, water, and waste. A partnership of local and regional agencies is needed to create a sustainable vision for the future that accommodates population growth in a carbon efficient way while meeting housing needs and other planning goals. Integration of the sustainable communities strategies or alternative planning strategies with local general plans will be key to the achievement of these goals. State, regional, and local agencies must work together to prioritize and create the supporting policies, programs, incentives, guidance, and funding to assist local actions to help ensure regional targets are met.

Enhanced public transit service combined with incentives for land use development that provides a better market for public transit will play an important role in helping to reach regional targets.

SB 375 maintains regions' flexibility in the development of sustainable communities strategies. There are many different ways regions can plan and work toward reducing the growth in vehicle travel. Increasing low-carbon travel choices (public transit, carpooling, walking and biking) combined with land use patterns and infrastructure that support these low-carbon modes of travel, can decrease average vehicle trip lengths by bringing more people closer to more destinations. The need for integrated strategies is supported by the current transportation and land use modeling literature.

Supporting measures that should be considered in both the regional target-setting and sustainable communities strategy processes include the following:

- Congestion pricing strategies can provide a method of efficiently managing traffic demand while raising funds for needed transit, biking and pedestrian infrastructure investment. Regional and local agencies, however, do not have the authority to pursue these strategies on their own, as federal approval and State authorization must be provided for regional implementation of most pricing measures.

- Indirect source rules for new development have already been implemented by some local air districts and proposed by others for purposes of criteria pollution reduction. Regions should evaluate the need for measures that would ensure the mitigation of high carbon footprint development outside of the sustainable communities strategies or alternative planning strategies that meet the targets established under SB 375.

- Programs to reduce vehicle trips while preserving personal mobility, such as employee transit incentives, telework programs, car sharing, parking policies, public education programs and other strategies that enhance and complement land use and transit strategies can be implemented and coordinated by regional and local agencies and stakeholder groups.

Another way to encourage greenhouse gas reductions from vehicle travel is through pay as you drive insurance (PAYD), a structure in which drivers realize a direct financial benefit from driving less. The California Insurance Commissioner recently announced support for PAYD and has proposed regulations to permit PAYD on a voluntary basis.

Separate emissions reduction estimates for these strategies are not quantified here. As regional targets are developed in the SB 375 process, ARB will work with regions to quantify the benefits in the context of the targets.

Estimating the Benefits of Regional Targets

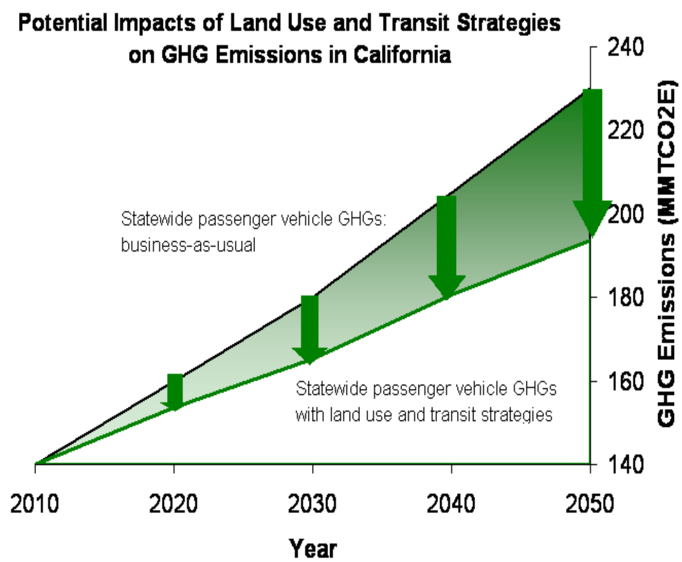
The ARB estimate of the statewide benefit of regional transportation-related greenhouse gas emissions reduction targets is based on analysis of research results quantifying the effects of land use and transportation strategies. The emissions reduction number in Table 11 is not the statewide metric for regional targets that must be developed as SB 375 is implemented. The emissions target will ultimately be determined during the SB 375 process.

The possible impacts of land use and transportation policies have been well documented. Most recently, a 2008 U.C. Berkeley study[38] reviewed over 20

[38]Rodier, Caroline. U.C. Berkeley, Transportation Sustainability Research Center, "A Review of the International Modeling Literature: Transit, Land Use, and Auto Pricing Strategies to Reduce Vehicle Miles Traveled and Greenhouse Gas Emissions," August 2008. http://www.arb.ca.gov/planning/tsaq/docs/rodier_8-1-08_trb_paper.pdf (accessed October 12, 2008)

modeling studies from California (including the State's four largest MPOs), other states and Europe. The study found a range of 0.4 to 7.7 percent reduction in vehicle miles traveled (VMT) resulting from a combination of land use and enhanced transit policies compared to a business-as-usual case over a 10-year horizon, with benefits doubling by 2030, as shown in Figure 4. With the inclusion of additional measures such as pricing policies, the reduction of greenhouse gas emissions can be greater. These strategies will be considered during the target-setting process. Sophisticated land use and transportation models can best assess these effects. As part of the development of regional targets, technical tools will need to be refined to ensure sound quantification techniques are available.

Figure 4



The potential benefits of this measure that can be realized by 2020 (as shown in Table 11) were estimated after first accounting for the benefits of the vehicle technology and efficiency measures in the plan. It was calculated based on the U.C. Berkeley study's median value of 4 percent per capita VMT reduction over a 10-year time horizon. This value should not be interpreted as the final estimate of the benefits of this measure. The current academic literature supports this realistic statewide estimate of potential benefits, but the ultimate benefit will be determined as an outcome of SB 375 implementation on a regional level. The incentives for sustainable planning in SB 375 can set California on a new path. ARB's establishment of regional targets in 2010, combined with the Regional Targets Advisory Committee process, required by the legislation, provides a clear mechanism for maximizing the benefits of this measure.

Additional Benefits of Regional Targets and Land Use Strategies

Land use and transportation measures that help reduce vehicle travel will also provide multiple benefits beyond greenhouse gas reductions. Quality of life will be improved by increasing access to a variety of mobility options such as transit, biking, and walking, and will provide a diversity of housing options focused on proximity to jobs, recreation, and services. Other important state and community goals that could be met through better integrated land use and transportation planning include agricultural, open space and habitat preservation, improved water quality, positive health effects, and the reduction of smog forming pollutants.

Growing more sustainably has the potential to provide additional greenhouse gas and energy savings by encouraging more compact, mixed-use developments resulting in reduced demand for electricity and heating and cooling energy. These land use-related energy savings will contribute toward the Plan's energy efficiency measures to achieve the goal of reducing electricity and natural gas usage. ARB is continuing to evaluate the greenhouse gas emissions reductions that may be additional to the proposed measures in this plan.

Table 11: Regional Transportation-Related Greenhouse Gas Targets Recommendation
(MMTCO_2E in 2020)

Measure No.	Measure Description	Reductions
T-3	Regional Transportation-Related Greenhouse Gas Targets[39]	5
	Total	**5**

7. Vehicle Efficiency Measures

Implement light-duty vehicle efficiency measures.

Several additional measures could reduce light-duty vehicle greenhouse gas emissions. The California Integrated Waste Management Board (CIWMB) with various partners continues to conduct a public awareness campaign to promote sustainable tire practices. ARB is pursuing a regulation to ensure that tires are properly inflated when vehicles are serviced. In addition, CEC in consultation with CIWMB is developing an efficient tire program focusing first on data gathering and outreach, then on potential adoption of minimum fuel-efficient tire standards, and lastly on the development of consumer information requirements for replacing tires. ARB is also pursuing ways to reduce engine load via lower friction oil and reducing the need for air conditioner use. ARB is actively engaged in the regulatory development process for the tire inflation component of this measure. Current information indicates the reduction of greenhouse gas emissions is likely to be less than estimated in the Draft Scoping Plan. ARB has adjusted the estimated reductions shown in Table 12 to reflect this.

[39] This number represents an estimate of what may be achieved from local land use changes. It is not the SB 375 regional target. ARB will establish regional targets for each MPO region following the input of the Regional Targets Advisory Committee and a public consultation process with MPOs and other stakeholders per SB 375.

Table 12: Vehicle Efficiency Recommendation
(MMTCO_2E in 2020)

Measure No.	Measure Description	Reductions
T-4	Vehicle Efficiency Measures	4.5
	Total	**4.5**

8. Goods Movement

Implement adopted regulations for the use of shore power for ships at berth. Improve efficiency in goods movement activities.

A significant portion of greenhouse gas emissions from transportation activities comes from the movement of freight or goods throughout the state. Activity at California ports is forecast to increase by 250 percent between now and 2020. Both the Goods Movement Emission Reduction Plan (GMERP) and the 2007 State Implementation Plan (SIP) contain numerous measures designed to reduce the public health impact of goods movement activities in California. ARB has already adopted a regulation to require ship electrification at ports. Proposition 1B funds, as well as clean air plans being implemented by California's ports, will also help reduce greenhouse gas emissions while cutting criteria pollutant and toxic diesel emissions. ARB is proposing to develop and implement additional measures to reduce greenhouse gas emissions due to goods movement from trucks, ports and other related facilities. The anticipated reductions would be above and beyond what is already expected in the GMERP and the SIP. This effort should provide accompanying reductions in air toxics and smog forming emissions. The estimated reduction of greenhouse gas emissions is shown in Table 13.

After further evaluation, ARB incorporated the Draft Scoping Plan's Heavy-Duty Vehicle-Efficiency measure into the Goods Movement measure. A Heavy-Duty Engine Efficiency measure could reduce emissions associated with goods movement through improvements which could involve advanced combustion strategies, friction reduction, waste heat recovery, and electrification of accessories. ARB will consider setting requirements and standards for heavy-duty engine efficiency in the future if higher levels of efficiency are not being produced either in response to market forces (fuel costs) or federal standards.

Table 13: Goods Movement Recommendation
(MMTCO_2E in 2020)

Measure No.	Measure Description	Reductions
T-5	Ship Electrification at Ports (Discrete Early Action)	0.2
T-6	Goods Movement Efficiency Measures • System-Wide Efficiency Improvements	3.5
	Total	**3.7**

9. Million Solar Roofs Program

Install 3,000 MW of solar-electric capacity under California's existing solar programs.

As part of Governor Schwarzenegger's Million Solar Roofs Program, California has set a goal to install 3,000 megawatts (MW) of new solar capacity by 2017 – moving the state toward a cleaner energy future and helping lower the cost of solar systems for consumers. The Million Solar Roofs Initiative is a ratepayer-financed incentive program aimed at transforming the market for rooftop solar systems by driving down costs over time. Created under Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), the Million Solar Roofs Program includes CPUC's California Solar Initiative and CEC's New Solar Homes Partnership, and requires publicly-owned utilities (POUs) to adopt, implement and finance a solar incentive program. This measure would offset electricity from the grid, thereby reducing greenhouse gas emissions. The estimated emissions reductions are shown in Table 14.

Obtaining the incentives requires the building owners or developers to meet certain efficiency requirements: specifically, that new construction projects meet energy efficiency levels that exceed the State's Title 24 Building Energy Efficiency Standards, and that existing commercial buildings undergo an energy audit. Thus, the program is also a mechanism for achieving the efficiency targets for the Energy sector. By requiring greater energy efficiency for projects that seek solar incentives, the State would be able to reduce both electricity and natural gas needs and their associated greenhouse gas emissions.

Table 14: Million Solar Roofs Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-4	Million Solar Roofs (including California Solar Initiative, New Solar Homes Partnership and solar programs of publicly owned utilities) • Target of 3000 MW Total Installation by 2020	2.1
	Total	**2.1**

10. Medium/Heavy-Duty Vehicles

Adopt medium and heavy-duty vehicle efficiency measures.

Medium- and heavy-duty vehicles account for approximately 20 percent of the transportation greenhouse gas inventory. Requiring retrofits to improve the fuel efficiency of heavy-duty trucks could include a requirement for devices that reduce aerodynamic drag and rolling resistance. In addition, hybridization of medium- and heavy-duty vehicles would also reduce greenhouse gas emissions through increased fuel efficiency. Hybrid trucks would likely achieve the greatest benefits in urban, stop-and-go applications, such as parcel delivery, utility services, transit, and other vocational work trucks. The recommendation for this sector is summarized in Table 15.

Table 15: Medium/Heavy-Duty Vehicle Recommendation (MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
T-7	Heavy-Duty Vehicle Greenhouse Gas Emissions Reduction Measure - Aerodynamic Efficiency (Discrete Early Action)	0.9
T-8	Medium/Heavy-Duty Vehicle Hybridization	0.5
	Total	**1.4**

11. Industrial Emissions

Require assessment of large industrial sources to determine whether individual sources within a facility can cost-effectively reduce greenhouse gas emissions and provide other pollution reduction co-benefits. Reduce greenhouse gas emissions from fugitive emissions from oil and gas extraction and gas transmission. Adopt and implement regulations to control fugitive methane emissions and reduce flaring at refineries.

Energy Efficiency and Co-Benefits Audits for Large Industrial Sources

This measure would apply to the direct greenhouse gas emissions at major industrial facilities emitting more than 0.5 MMTCO$_2$E per year. In general, these facilities also have significant emissions of criteria air pollutants, toxic air pollutants, or both. Major industrial facilities include power plants, refineries, cement plants, and miscellaneous other sources. ARB would implement this measure through a regulation, requiring each facility to conduct an energy efficiency audit of individual combustion and other direct sources of greenhouse gases within the facility to determine the potential reduction opportunities, including criteria air pollutants and toxic air contaminants. The audit would include an assessment of the impacts of replacing or upgrading older, less efficient units such as boilers and heaters, or replacing the units with combined heat and power (CHP) units. The measure is summarized in Table 16.

The audit would help ARB to identify potential reductions of greenhouse gas emissions reductions, the associated costs and cost-effectiveness, their technical feasibility, and the potential to reduce air pollution impacts at the local or regional level. ARB will use the results to determine if certain emissions sources within a facility can make cost-effective reductions of greenhouse gas emissions that also provide reductions in other criteria or toxic pollutants. Where this is the case, rule provisions or permit conditions would be considered to ensure the best combination of pollution reductions. Nothing in this measure would delay known cost-effective strategies that otherwise would be required.

The California Long Term Energy Efficiency Strategic Plan (CPUC) discusses a number of strategies associated with improving industrial sector efficiency and greenhouse gas emissions reductions, including the development of certification protocols for industrial efficiency improvements to develop market recognition for efficiency gains.

Oil and Gas Recovery Operations and Transmission/Refineries

California is a major oil and gas producer. Crude oil, both from in-state and imported sources, is processed at 21 oil refineries in the state. In addition to conforming to the requirements of the cap-and-trade program and the audit measure, ARB has identified four specific measures for development and implementation, two for oil and gas recovery operations and gas transmission, and two for refineries. Other industrial measures that were under consideration affect greenhouse gas emissions sources that are fully regulated under cap and trade, which ARB concluded would provide cost-effective reductions of greenhouse gas emissions. All measures would be designed to secure a combination of cost-effective reductions in greenhouse gas emissions, criteria air pollutants and air toxics. Two measures would be developed to reduce methane emissions in the oil and gas production and gas transmission processes from leaks and incomplete combustion of methane (used as fuel). These measures would include improved leak detection, process modifications, equipment retrofits, installation of new equipment, and best management practices. The first measure would affect oil and gas producers. The second would impact operators of natural gas pipeline systems. These fugitive emissions are not proposed to be covered by a cap and trade program, although combustion-related emissions from these operations are proposed to be covered. The WCI partner jurisdictions are currently evaluating the inclusion of fugitive methane emissions to the extent that adequate quantification methods exist. During implementation of this measure, ARB will determine whether these emissions will also be covered in California's cap-and-trade program. If the emissions are covered under the cap, ARB will evaluate the need for the measures described here.

Two measures would be developed for oil refineries. The first would limit the greenhouse gas emissions from refinery flares while preserving flaring as needed for safety reasons. The second would remove the current fugitive methane exemption in most refinery Volatile Organic Compounds (VOC) regulations. This exemption was established because methane does not appreciably contribute to urban smog, but is inappropriate given the role that methane plays in global warming. ARB believes these measures would provide cost-effective greenhouse gas, criteria pollutants and air toxics emissions reductions. Most combustion and other process emissions at refineries would be governed by the cap-and-trade program. As with the oil and gas production measures above, the need for these measures would be evaluated if fugitive methane is included in the WCI cap-and-trade program.

Table 16: Industrial Emissions Recommendation
(MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
I-1	Energy Efficiency and Co-Benefits Audits for Large Industrial Sources	TBD
I-2	Oil and Gas Extraction GHG Emissions Reduction	0.2
I-3	GHG Leak Reduction from Oil and Gas Transmission	0.9
I-4	Refinery Flare Recovery Process Improvements	0.33
I-5	Removal of Methane Exemption from Existing Refinery Regulations	0.01
	Total	**1.4**

12. High Speed Rail

Support implementation of a high speed rail system.

A high speed rail (HSR) system is part of the statewide strategy to provide more mobility choice and reduce greenhouse gas emissions. This measure supports implementation of plans to construct and operate a HSR system between northern and southern California. As planned, the HSR is a 700-mile-long rail system capable of speeds in excess of 200 miles per hour on dedicated, fully-grade separated tracks with state-of-the-art safety, signaling and automated rail control systems. The system would serve the major metropolitan centers of California in 2030 and is projected to displace between 86 and 117 million riders from other travel modes in 2030.

For Phase 1 of the HSR, between San Francisco and Anaheim, 2020 is projected to be the first year of service, with 26 percent of the projected 2030 full system ridership levels. The anticipated reduction of greenhouse gas emissions are shown in Table 17. HSR system ridership and the benefits associated with it are anticipated to increase over time as additional portions of the planned system are completed. Over the long term, the system also has the potential to support the reduction of greenhouse gas emissions in the transportation sector from land use strategies, by providing opportunities for and encouraging low-impact transit-oriented development.

HSR implementation was initiated recently when California voters approved Proposition 1A, the "Safe, Reliable High-Speed Passenger Train Bond Act for the 21st Century," as it appeared on the November 2008 ballot. HSR is anticipated to begin in 2010, with full implementation anticipated in 2030.

Table 17: High Speed Rail Recommendation
(MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
T-9	High Speed Rail	1.0
	Total	**1.0**

13. Green Building Strategy

Expand the use of green building practices to reduce the carbon footprint of California's new and existing inventory of buildings.

Collectively, energy use and related activities by buildings are the second largest contributor to California's greenhouse gas emissions. Almost one-quarter of California's greenhouse gas emissions can be attributed to buildings.[40] As the Governor recognized in his Green Building Initiative (Executive Order S-20-04), significant reductions in greenhouse gas emissions can be achieved through the design and construction of new green buildings as well as the sustainable operation, retrofitting, and renovation of existing buildings.

A Green Building strategy offers a comprehensive approach to reducing direct and upstream greenhouse gas emissions that cross-cuts multiple sectors including Electricity/Natural Gas, Water, Recycling/Waste, and Transportation. Green buildings are designed, constructed, renovated, operated, and maintained using an integrated approach that reduces greenhouse gas emissions by maximizing energy and resource efficiency. Employing a whole-building design approach can create tremendous synergies that result in multiple benefits at little or no net cost, allowing for efficiencies that would never be possible on an incremental basis.

A Green Building strategy will produce greenhouse gas saving through buildings that exceed minimum energy efficiency standards, decrease consumption of potable water, reduce solid waste during construction and operation, and incorporate sustainable materials. Combined these measures can also contribute to healthy indoor air quality, protect human health and minimize impacts to the environment. A Green Building strategy also includes siting considerations. Buildings that are sited close to public transportation or near mixed-use areas can work in tandem with transportation-related strategies to decrease greenhouse gas emissions that result from that sector.

In July 2008, the California Building Standards Commission (CBSC) adopted the Green Building Standards Code (GBSC) for all new construction in the state. While the current version of the commercial green building code is voluntary, CBSC anticipates adopting a mandatory code in 2011 which will institute minimum environmental performance standards for all occupancies. The Green Building Strategy includes Zero Net Energy (ZNE) goals for new and existing homes and commercial buildings consistent with the recently-adopted California Long Term Energy Efficiency Strategic Plan. ARB encourages local governments to raise the bar by adopting "beyond-code" green building requirements. To assist this effort, State government would develop and regularly tighten voluntary standards, written in GBSC language for easy adoption by local jurisdictions.

[40] Greenhouse gas emission estimates from electricity, natural gas, and water use in homes and commercial buildings.

As we approach the 2020 and 2030 targets for zero energy buildings, these "percent above code" targets must shift to "percent of ZNE" targets. Zero energy new and existing buildings can be an overarching and unifying concept for energy efficiency in buildings, as discussed above (building energy efficiency measures E-1 and CR-1). In order to achieve statewide GHG emission reductions, these targets should be expanded to address other aspects of environmental performance. For example, these targets could be re-framed as a carbon footprint reduction goal for a 35 percent reduction in both energy and water consumption. For commercial buildings, a 2011 target should be established such that a quarter of all new buildings reduce energy and water consumption by at least 25 percent beyond code.

Furthermore, retrofitting existing residential and commercial buildings would achieve substantial greenhouse gas emissions reduction benefits. This Scoping Plan recommends the establishment of an environmental performance rating system for homes and commercial buildings and further recommends that California adopt mechanisms to encourage and require retrofits for buildings that do not meet minimum standards of performance.

An effective green building framework can operate to deliver reductions of greenhouse gas emissions in multiple sectors. The green building strategies provide a vehicle to achieve the statewide electricity and natural gas efficiency targets and lower greenhouse gas emissions from the waste and water transport sectors. Achieving these green building emissions reductions will require coordinated efforts from a broad range of stakeholders, and new financing mechanisms to motivate investment in green building strategies.

Achieving significant greenhouse gas emissions reductions from new and existing buildings will require a combination of green building measures for new construction and retrofits to existing buildings. The State of California will set an example by requiring all new State buildings to exceed existing Green Building Initiative energy goals and achieve nationally-recognized building sustainability standards such as Leadership in Energy and Environmental Design - New Construction (LEED-NC) "Gold" certification. Existing State buildings would also be retrofitted to achieve higher standards equivalent to LEED-EB for existing buildings (EB) "Silver." All new schools should be required to meet the Collaborative for High Performance Schools (CHPS) 2009 criteria. Existing schools applying for modernization funds should also be required to meet CHPS 2009 criteria.

ARB estimates that the greenhouse gas savings from green building measures as approximately 26 $MMTCO_2E$, as shown in Table 18 below. Most of these reductions are accounted for in the Electricity, Waste and Water sectors. Because of this, ARB has assigned all emissions reductions that occur as a result of green building strategies to other sectors for purposes of meeting AB 32 requirements, but will continue to evaluate and refine the emissions from this sector. As such, this strategy will require implementation from various entities within California, including CEC, PUC, State Architect, and others, each taking the lead in their area of authority and expertise.

Table 18: Green Buildings Recommendation
(MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
GB-1	Green Buildings[41]	26
	Total	**26**

14. High Global Warming Potential Gases

Adopt measures to reduce high global warming potential gases.

High global warming potential (GWP) gases pose a unique challenge. Just a few pounds of high GWP materials can have the equivalent effect on global warming as several *tons* of carbon dioxide. For example, the average refrigerator has about a half-pound of refrigerant and about one pound of “blowing agents” used to make the insulating foam. If these gases were released into the atmosphere, they would have a global warming impact equivalent to five metric tons of CO_2.

High GWP chemicals are very common and are used in many different applications such as refrigeration, air conditioning systems, fire suppression systems, and the production of insulating foam. Because these gases have been in use for years, old refrigerators, air conditioners and foam insulation represent a significant “bank” of these materials yet to be released. High GWP gases are released primarily in two ways. The first is through leaking systems, and the second is during the disposal process. Once high GWP materials are released, they persist in the atmosphere for tens or even hundreds of years. Recommended measures to address this growing problem take the form of direct regulations and use of mitigation fees.

ARB identified four Discrete Early Action measures to reduce greenhouse gas emissions from the refrigerants used in car air conditioners, semiconductor manufacturing, air quality tracer studies, and consumer products. ARB has identified additional potential reduction opportunities based on specifications for future commercial and industrial refrigeration, changing the refrigerants used in auto air conditioning systems, and ensuring that existing car air conditioning systems as well as stationary refrigeration equipment do not leak. Recovery and destruction of high GWP materials in the banks described above could also provide significant reductions.

[41] Although some of these emissions reductions may be additional, most of them are accounted for in the Energy, Waste, Water, and Transportation sectors. In addition, some of these reductions may occur out of state, making quantification more difficult. Because of this, these emissions reductions are not currently counted toward the AB 32 2020 goal.

ARB is also proposing to establish an upstream mitigation fee on the use of high GWP gases. Even with the reductions from the specific high GWP measures described above, this sector's emissions are still projected to more than double from current levels by 2020. This is because of the high growth in the sector due, in part, to the replacement of ozone-depleting substances being phased out of production. These emissions would be difficult to address via traditional approaches since the gases are used in small quantities in very diverse applications. Additionally, there are no proven substitutes or alternatives for some uses, and the relative low price of most high GWP compounds provides little incentive to develop alternatives, reduce leakage, or recover the gases at end-of-life.

An upstream fee would ensure that the climate impact of these substances is reflected in the total cost of the product, encouraging reduced use and end-of-life losses, as well as the development of alternatives. The fee would be variable and associated with the impact the product makes on public health and the environment. This could encourage product innovation because fees would correspondingly decrease as the manufacturer or producer redesigned their product or found lower-cost alternatives. This mitigation fee would complement many of the downstream high GWP regulations currently being developed.[42] Fees on high GWP gases would be set to be consistent with the cost of reducing greenhouse gas emissions and could be set to reduce multiple environmental impacts. Revenues could be used to mitigate greenhouse gas emissions either from other high GWP compounds or other greenhouse gases.

Table 19 summarizes the recommendations for measures in the High GWP sector. These measures address both high GWP gases identified in AB 32 and also other high GWP gases, such as ozone-depleting substances that are only partially covered by the Montreal Protocol. The emissions reductions shown are only for the six greenhouse gases explicitly identified in AB 32.

[42] Industrial process emissions of high GWP gases are also expected to be part of the cap-and-trade program. As ARB moves through the rulemaking for both the high GWP fee and the cap-and-trade program, staff will evaluate whether these are complementary approaches or if one or the other needs to be adjusted to prevent duplicative regulation of the industrial process emissions of these gases.

Table 19: High GWP Gases Sector Recommendation
(MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
H-1	Motor Vehicle Air Conditioning Systems: Reduction of Refrigerant Emissions from Non-Professional Servicing (Discrete Early Action)	0.26
H-2	SF_6 Limits in Non-Utility and Non-Semiconductor Applications (Discrete Early Action)	0.3
H-3	Reduction of Perfluorocarbons in Semiconductor Manufacturing (Discrete Early Action)	0.15
H-4	Limit High GWP Use in Consumer Products (Discrete Early Action) (Adopted June 2008)	0.25
H-5	High GWP Reductions from Mobile Sources • Low GWP Refrigerants for New Motor Vehicle Air Conditioning Systems • Air Conditioner Refrigerant Leak Test During Vehicle Smog Check • Refrigerant Recovery from Decommissioned Refrigerated Shipping Containers • Enforcement of Federal Ban on Refrigerant Release during Servicing or Dismantling of Motor Vehicle Air Conditioning Systems	3.3
H-6	High GWP Reductions from Stationary Sources • High GWP Stationary Equipment Refrigerant Management Program: o Refrigerant Tracking/Reporting/Repair Deposit Program o Specifications for Commercial and Industrial Refrigeration Systems • Foam Recovery and Destruction Program • SF_6 Leak Reduction and Recycling in Electrical Applications • Alternative Suppressants in Fire Protection Systems • Residential Refrigeration Early Retirement Program	10.9
H-7	Mitigation Fee on High GWP Gases[43]	5
	Total	**20.2**

[43] The 5 MMTCO$_2$E reduction is an estimate of what might occur with a fee in place. Additional emissions reductions from a fee would be expected as resulting revenues are used in mitigation programs. Using the funds to mitigate greenhouse gas emissions could substantially increase the emissions reductions from this measure.

15. Recycling and Waste

Reduce methane emissions at landfills. Increase waste diversion, composting and other beneficial uses of organic materials, and mandate commercial recycling. Move toward zero-waste.

California has a long track record of reducing greenhouse gas emissions by turning waste into resources, exemplified by the waste diversion rate from landfills of 54 percent (which exceeds the current 50 percent mandate) resulting from recovery of recyclable materials. Re-introducing recyclables with intrinsic energy value back into the manufacturing process reduces greenhouse gas emissions from multiple phases of product production including extraction of raw materials, preprocessing and manufacturing. Additionally, by recovering organic materials from the waste stream, and having a vibrant composting and organic materials industry, there is an opportunity to further reduce greenhouse gas emissions through the indirect benefits associated with the reduced need for water and fertilizer for California's Agricultural sector. Incentives may also be an effective way to secure greenhouse gas emissions reductions in this sector. Table 20 summarizes the emissions reductions from Recycling and Waste sector.

Reduction in Landfill Methane

Methane emissions from landfills, generated when wastes decompose, account for one percent of California's greenhouse gas emissions. Greenhouse gas emissions can be substantially reduced by properly managing all materials to minimize the generation of waste, maximize the diversion from landfills, and manage them to their highest and best use. Capturing landfill methane results in greenhouse gas benefits, as well as reductions in other air pollutants such as volatile organic compounds. ARB is working closely with the California Integrated Waste Management Board (CIWMB) to develop a Discrete Early Action measure for landfill methane control that will be presented to ARB in January.

CIWMB is also pursuing efforts to reduce methane emissions by diverting organics from landfills, and to promote best management practices at smaller uncontrolled landfills. Landfill gas may also provide a viable source of liquefied natural gas (LNG) vehicle fuel. Reductions from these types of projects would be accounted for in the Transportation sector.

High Recycling / Zero Waste

This measure reduces greenhouse gas emissions primarily by reducing the substantial energy use associated with the acquisition of raw materials in the manufacturing stage of a product's life-cycle. As virgin raw materials are replaced with recyclables, a large reduction in energy consumption should be realized. Implementing programs with a systems approach that focus on consumer demand, manufacturing, and movement of products will result in the reduction of greenhouse gas emissions and other co-benefits. Reducing waste and materials at the source of generation, increased use of organic materials to produce compost to benefit soils and to produce biofuels and energy, coupled with increased recycling – especially in the commercial sector – and Extended Producer Responsibility (EPR) plus Environmentally Preferable Purchasing (EPP) also have the potential to reduce emissions, both in-state and within the connected global economy. This measure could also assist in meeting the 33 percent renewables energy goal through deployment of anaerobic digestion for production of fuels/energy.

As noted by ETAAC, recycling in the commercial sector could be substantially increased. This will be implemented through mandatory programs and enhanced partnerships with local governments. The provision of appropriate financial incentives will be critical. ARB will work with CIWMB to develop and implement these types of programs. ARB will also work with CIWMB, the California Department of Food and Agriculture, the Department of Transportation, and others to provide direct incentives for the use of compost in agriculture and landscaping. Further, CIWMB will explore the use of incentives for all Recycling and Waste Management measures, including for commercial recycling and for local jurisdictions to encourage the collection of residentially and commercially-generated food scraps for composting and in-vessel anaerobic digestion.

Table 20: Recycling and Waste Sector Recommendation - Landfill Methane Capture and High Recycling/Zero Waste

($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
RW-1	Landfill Methane Control (Discrete Early Action)	1
RW-2	Additional Reductions in Landfill Methane • Increase the Efficiency of Landfill Methane Capture	TBD
RW-3	High Recycling/Zero Waste • Mandatory Commercial Recycling • Increase Production and Markets for Organics Products • Anaerobic Digestion • Extended Producer Responsibility • Environmentally Preferable Purchasing	 5 2 2 TBD TBD
	Total	**10**(44)

[44] Reductions from RW-2 and RW-3 are not counted toward the AB 32 goal. ARB is continuing to work with CIWMB to quantify these emissions and determine what portion of the reductions can be credited to meeting the AB 32 2020 goal. These measures may provide greater emissions reductions than estimated.

16. Sustainable Forests

Preserve forest sequestration and encourage the use of forest biomass for sustainable energy generation.

The 2020 Scoping Plan target for California's forest sector is to maintain the current 5 $MMTCO_2E$ of sequestration through sustainable management practices, potentially including reducing the risk of catastrophic wildfire, and the avoidance or mitigation of land-use changes that reduce carbon storage. California's Board of Forestry and Fire Protection has the existing authority to provide for sustainable management practices, and will, at a minimum, work to maintain current carbon sequestration levels. The Resources Agency and its departments will also have an important role to play in implementing this measure.

In addition, the Resources Agency is supporting voluntary actions, including expenditure of public funds for projects focused largely on conserving biodiversity, providing recreation, promoting sustainable forest management and other projects that also provide carbon sequestration benefits. The federal government must also use its regulatory authority to, at a minimum, maintain current carbon sequestration levels for land under its jurisdiction in California.

Forests in California are now a carbon sink. This means that atmospheric removal of carbon through sequestration is greater than atmospheric emissions from processes like fire and decomposition of wood. However, several factors, such as wildfires and forest land conversion, may cause a decline in the carbon sink. The 2020 target would provide a mechanism to help ensure that current carbon stocks are, at a minimum, maintained and do not diminish over time. The 5 $MMTCO_2E$ emission reduction target is set equal to the magnitude of the current estimate of net emissions from California's forest sector. As technical data improve, the target can be recalibrated to reflect new information.

California's forests will play an even greater role in reducing carbon emissions for the 2050 greenhouse gas emissions reduction goals. Forests are unique in that planting trees today will maximize their sequestration capacity in 20 to 50 years. As a result, near-term investments in activities such as planting trees will help us reach our 2020 target, but will also play a greater role in reaching our 2050 goals.

Monitoring carbon sequestered on forest lands will be necessary to implement the target. The Board of Forestry and Fire Protection, working with the Resources Agency, the Department of Forestry and Fire Protection and ARB would be tasked with developing a monitoring program, improving greenhouse gas inventories, and determining what actions are needed to meet the 2020 target for the Forest sector. Future climate impacts will exacerbate existing wildfire and insect disturbances in the Forest sector. These disturbances will create new uncertainties in reducing emissions and maintaining sequestration levels over the long-term, requiring more creative strategies for adapting to these changes. In the short term, focusing on sustainable management practices and land-use issues is a practical approach for moving forward.

Future land use decisions will play a role in reaching our greenhouse gas emissions reduction goals for all sectors. Loss of forest land to development increases greenhouse gas emissions levels because less carbon is sequestered. Avoiding or mitigating such conversions will support efforts to meet the 2020 goal. When significant changes occur, the California Environmental Quality Act is a mechanism providing for assessment and mitigation of greenhouse gas emissions.

Going forward there are a number of forestry-related strategies that can play an important role in California's greenhouse gas emissions reduction efforts. Biomass resources from forest residue will factor into the expansion of renewable energy sources (this is currently accounted for in the Energy sector). Similarly, fuels management strategies have the potential to reduce the risk of catastrophic fires. However, fuels management needs to be evaluated to determine whether, and if so under what circumstances, quantifiable greenhouse gas emission reductions are achieved. Additionally, public investments to purchase and preserve forests and woodlands would also provide greenhouse gas emission reductions that will be accounted for as projects are funded. Urban forest projects can also provide the dual benefit of carbon sequestration and shading to reduce air conditioning load.

Furthermore, the Forest sector currently functions as a source of voluntary reductions that would not otherwise occur and this role could expand even further in the future. ARB has already adopted a methodology to quantify reductions from forest projects, and recently adopted additional quantification methodologies. Table 21 summarizes the emission reductions from the forest measure.

Table 21: Sustainable Forests Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
F-1	Sustainable Forest Target	5
	Total	**5**

17. Water

Continue efficiency programs and use cleaner energy sources to move and treat water.

Water use requires significant amounts of energy. Approximately one-fifth of the electricity and one-third of the non-power plant natural gas consumed in the state are associated with water delivery, treatment and use. Although State, federal, and local water projects have allowed the state to grow and meet its water demands, greenhouse gas emissions can be reduced if we can move, treat, and use water more efficiently. As is the case with energy efficiency, California has a long history of advancing water efficiency and conservation programs. Without this ongoing, critical work, baseline or business-as-usual greenhouse gas emissions associated with water use would be much higher than is currently the case.

Six greenhouse gas emissions reduction strategies measures are proposed for the Water sector, and are shown in Table 22. Three of the measures target reducing energy requirements associated with providing reliable water supplies and two measures are aimed at reducing the amount of non-renewable electricity associated with conveying and treating water. The final measure focuses on providing sustainable funding for implementing these actions. The greenhouse gas emissions reductions from these measures are indirectly realized through reduced energy requirements and are accounted for in the Electricity and Natural Gas sector.

In addition, a mechanism to make allowances available in a cap-and-trade program could be used to provide additional incentives for local governments, water suppliers, and third party providers to bundle water and energy efficiency improvements. This type of allowance set-aside will be evaluated during the rulemaking for the cap-and-trade program.

ARB recommends a public goods charge for funding investments in water management actions that improve water and energy efficiency and reduce GHG emissions. As noted by the Economic and Technology Advancement Advisory Committee, a public goods charge on water can be collected on water bills and then used to fund end-use water efficiency improvements, system-wide efficiency projects, water recycling, and other actions that improve water and energy efficiency and reduce GHG emissions. Depending on how the fee schedule is developed in a subsequent rulemaking process, a public goods charge could generate $100 million to $500 million. These actions would also have the co-benefit of improving water quality and water supply reliability for customers.

Table 22: Water Recommendation
(MMTCO$_2$E in 2020)

Measure No.	Measure Description	Reductions
W-1	Water Use Efficiency	1.4
W-2	Water Recycling	0.3
W-3	Water System Energy Efficiency	2.0
W-4	Reuse Urban Runoff	0.2
W-5	Increase Renewable Energy Production	0.9
W-6	Public Goods Charge	TBD
	Total	**4.8**[45]

[45] Greenhouse gas emission reductions from the water sector are not currently counted toward the 2020 goal. ARB anticipates that a portion of these reductions will be additional to identified reductions in the Electricity sector and is working with the appropriate agencies to refine the electricity/water emissions inventory.

18. Agriculture

In the near-term, encourage investment in manure digesters and at the five-year Scoping Plan update determine if the program should be made mandatory by 2020.

Encouraging the capture of methane through use of manure digester systems at dairies can provide emission reductions on a voluntary basis. This measure is also a renewable energy strategy to promote the use of captured gas for fuels or power production. Initially, economic incentives such as marketable emission reduction credits, favorable utility contracts, or renewable energy incentives will be needed. Quantified reductions for this measure (shown in Table 23) are not included in the sum of statewide reductions shown in Table 2 since the initial approach is voluntary. ARB and the California Climate Action Registry worked together on a manure digester protocol to establish methods for quantifying greenhouse gas emissions reductions from individual projects; the Board adopted this protocol in September 2008. The voluntary approach will be re-assessed at the five-year update of the Scoping Plan to determine if the program should become mandatory for large dairies by 2020.

Nitrogen fertilizer, which produces N_2O emissions, is the other significant source of greenhouse gases in the Agricultural sector. ARB has begun a research program to better understand the variables affecting fertilizer N_2O emissions (Phase 1), and based on the findings, will explore opportunities for emission reductions (Phase 2).

There may be significant potential for additional voluntary reductions in the agricultural sector through strategies, such as those recommended by ETAAC. These opportunities include increases in fuel efficiency of on-farm equipment, water use efficiency, and biomass utilization for fuels and power production.

Increasing carbon sequestration, including on working rangelands, hardwood and riparian woodland reforestation, also hold potential as a greenhouse gas strategies. As we evaluate the role that this sector can play in California's emissions reduction efforts, we will explore the feasibility of developing sound quantification protocols so that these and other related strategies may be employed in the future.

Table 23: Agriculture Recommendation
(MMTCO_2E in 2020)

Measure No.	Measure Description	Reductions
A-1	Methane Capture at Large Dairies[46]	1.0
	Total	**1.0**

[46] Because the emission reductions from this measure are not required, they are not counted in the total.

D. Voluntary Early Actions and Reductions

Many individual activities that are not currently addressed under regulatory approaches can nevertheless result in cost-effective, real, additional, and verifiable greenhouse gas emissions reductions that will help California meet its 2020 target. Ensuring that appropriate credit is available to these types of emissions reduction projects will also help jump-start a new wave of technologies that will feature prominently in California and the world's long-term efforts to combat climate change. ARB will pursue several approaches that will recognize and reward these types of projects.

1. Voluntary Early Action

ARB is required to design regulations to encourage early action to reduce greenhouse gas emissions, and to provide appropriate recognition or credit for that action. (HSC §38562(b)(1) and (3)) Recognizing and rewarding greenhouse gas emissions reductions that occur prior to the full implementation of the AB 32 program can set the stage for innovation by incentivizing the development and employment of new clean technologies and by generating economic and environmental benefits for California.

In February 2008, ARB adopted a policy statement encouraging the early reductions of greenhouse gas emissions.[47] The policy statement describes a process for interested parties to submit proposed emission quantification methodologies for voluntary greenhouse gas emissions reductions to ARB for review. The intent is to provide a rapid assessment of methodologies for evaluating potential greenhouse gas emissions reduction projects to encourage early actions. Where appropriate, ARB will issue Executive Orders to confirm the technical soundness of the methodologies, and the methodology would be available for use by other parties to demonstrate the creation of voluntary early reductions. ARB is currently in the process of evaluating a number of submitted project methodologies.

ARB will provide appropriate credit for voluntary early reductions that can be adequately quantified and verified through three primary means. First, within the cap-and-trade program, ARB would set aside a certain number of allowances from the first compliance period to use to reward voluntary reductions that occur before 2012. In addition, ARB will assure that the allocation process in the first compliance period does not disadvantage facilities that have made reductions after AB 32 went into effect at the start of 2007 and before 2012.[48] The third approach will be to design

[47]Board Meeting Agenda. California Air Resources Board. February 28, 2008. http://www.arb.ca.gov/board/ma/2008/ma022808.htm (accessed October 12, 2008)

[48] ARB will evaluate whether some reductions that occurred prior to AB 32 going into effect on January 1, 2007, should also receive credit under these rules. For example, many facilities in California registered with the California Climate Action Registry after its creation in 2002 to document early actions to reduce emissions by having a record of entities profiles and baselines. ARB will evaluate what reductions made prior to 2007 should be eligible for credit from the allowance set-aside as part of the cap-and-trade program rulemaking.

other regulations, to the extent feasible, to recognize and reward early action. These approaches are discussed in more detail in Appendix C.

2. Voluntary Reductions

Emissions reduction projects that are not otherwise regulated, covered under an emissions cap, or undertaken as a result of government incentive programs can generate "offsets." These are verifiable reductions whose ownership can be transferred to others. Voluntary offset markets have recently flourished as a way for companies and individuals to offset their own emissions by purchasing reductions outside of their own operations. These sorts of voluntary efforts to reduce greenhouse gas emissions can play an important role in helping the State meet its overall greenhouse gas reduction goals.

ARB will adopt methodologies for quantifying voluntary reductions. (HSC §38571) The Board adopted a methodology for forest projects in October 2007 and for urban forestry and manure digesters in September 2008. The recognition of voluntary reduction or offset methodologies does not in any way guarantee that these offsets can be used for other compliance purposes. The Board would need to adopt regulations to verify and enforce reductions achieved under these or other approved methodologies before they could be used for compliance purposes. (HSC §38571)

Allowance set-asides, in addition to being used to potentially reward voluntary early actions by facilities that will be included in the cap-and-trade program, could also be used to reward voluntary early action at other facilities not covered by the cap and to ensure that voluntary actions, such as voluntary renewable power purchases by individuals, businesses, and others, serve to reduce greenhouse gas emissions under the cap. An early action allowance set-aside could be utilized both by entities that are covered by the cap, and by those who develop emissions reducing projects outside of the cap, or purchase the reductions associated with those projects, and have not sold or used them. Additional discussion of voluntary offsets is included in Appendix C.

E. Use of Allowances and Revenues

Revenues may be generated from the implementation of various proposed components of the Scoping Plan, including by the use of auctions within a cap-and-trade system or through the imposition of more targeted measures, such as a public goods charge on water. These revenues could be used to support AB 32 requirements for greenhouse gas emissions reductions and associated socio-economic considerations. This section summarizes some of the recommendations and ideas that ARB has received to date. As discussed in the description of the cap-and-trade measure above, ARB will seek input from a broad range of experts in an open public process regarding the options for allocation and revenue use under consideration.

The Economic and Technology Advancement Advisory Committee (ETAAC) recommended the creation of a California Carbon Trust as a possible mechanism for using revenues generated by the program, leveraged with private funds, to further the overall program goals. ETAAC's recommendation is roughly based on the United Kingdom Carbon Trust. The United Kingdom program was established with public funds, but now functions as a stand-alone corporation, providing management and consulting services to corporations and small and medium businesses on reducing greenhouse gas emissions. It also funds innovations in carbon reduction technologies. ETAAC recommended the creation of a similar organization that would use revenue from the sale of carbon allowances or from carbon fees to:

- Fund research, development and demonstration projects,
- Help bring promising and high potential technologies through the often challenging early stages of development and get them to market,
- Manage the early carbon market and mitigate price volatility, purchasing credits and selling them or retiring them as needed,
- Dedicate resources to fund projects to achieve AB 32 Environmental Justice goals, or
- Support a green technology workforce training program.

The most appropriate use for some of the allowances and revenue generated under AB 32 may be to retain it within or return it to the sector from which it was generated. For example, CEC and CPUC specifically recommended that significant portions of the revenue generated from the electricity sector under a cap-and-trade program be used for the benefit of that sector to support investments in renewable energy, efficiency, new energy technology, infrastructure, customer utility bill relief, and other similar programs. In the case of more targeted revenues from a public goods charge, the intent would be to use the funds for program purposes within the sector in which it was raised, for example in the water sector. ARB will seek input from a broad range of experts in an open public process, and will work with other agencies, the WCI partner jurisdictions, and stakeholders to consider the options for use of revenues from the AB 32 program.

Possible uses of allowances and of the revenue generated under the program include:

- **Reducing costs of emissions reductions or achieving additional reductions –** Funding energy efficiency and renewable resource development could lower overall costs to consumers and companies, and provide the opportunity to achieve greater emissions reductions than would otherwise be possible. Program revenues could be used to fund programs directly, or create financial incentives for others. Allowance set-asides could also be used to provide incentives for voluntary renewable power purchases by individuals and businesses, and for increased energy efficiency.
- **Achieving environmental co-benefits –** Criteria and toxic air pollutants create health risks, and some communities bear a disproportionate burden from air pollution. Revenues could be used to enhance greenhouse gas emission reductions that also provide reductions in air and other pollutants that affect public health.

- **Incentives to local governments –** Funding or other incentives to local governments for well-designed land-use planning and infrastructure projects could lead to shorter commutes and encourage walking, bicycling and the use of public transit. Funding of other incentives for local governments could also be used to increase recycling, composting, and to generating renewable energy from anaerobic digestion.
- **Consumer rebates –** Utilities and other businesses could use revenues to support and increase rebate programs to customers to offset some of the cost associated with increased investments in renewable resources and to encourage increased energy efficiency.
- **Direct refund to consumers –** Revenue from the program could be recycled directly back to consumers in a variety of forms including per capita dividends, earned income tax credits, or other mechanisms.
- **Climate change adaptation programs –** Climate change will impact natural and human environments. Program revenues could be used to help the state adapt to the effects of climate change which will be detailed in the State's Climate Adaptation Strategy being prepared by the Resources Agency to be completed in early 2009.
- **Subsidies –** Revenues could be used to reduce immediate cost impacts to covered industries required to make substantial upfront capital investments to reduce greenhouse gas emissions.
- **RD&D funding –** Revenues could be used to support research, development, and deployment of green technologies.
- **Worker transition assistance –** Regulating greenhouse gas emissions will probably shift economic growth to some sectors and green technologies and away from higher carbon intensity industries. Worker training programs could help the California labor force be competitive in these new industries.
- **Administration of a greenhouse gas program –** A portion of revenues could be used to underwrite the State's AB 32 programs and operating costs.
- **Direct emission reductions –** Revenues could be used to purchase greenhouse gas reductions for the sole purpose of retirement, providing direct additional greenhouse gas emission reductions. Potential projects, such as afforestation and reforestation, would both sequester CO_2 and provide other environmental benefits.

Many of the potential uses of revenue would help ARB implement the community benefit section of the AB 32 (HSC §38565) which directs the Board, where applicable and to the extent feasible, to ensure that the greenhouse gas emissions reduction program directs public and private investment toward the most disadvantaged communities in California.

This page intentionally blank

III. EVALUATIONS

The primary purpose of the Scoping Plan is to develop a set of measures that will provide the maximum technologically feasible and cost-effective greenhouse gas emission reductions. In developing this Plan, ARB evaluated the effect of these measures on California's economy, environment, and public health. This Chapter outlines these analyses.

ARB conducted broad evaluations of the potential impacts of the Scoping Plan, and will conduct more specific evaluations during regulatory development (HSC §38561(d), and HSC §38562(b)). Prior to inclusion of market-based compliance mechanisms in a regulation, to the extent feasible, the Board will consider direct, indirect and cumulative emission impacts, and localized impacts in communities that are already adversely impacted by air pollution (HSC §38570(b)).

Based on the evaluation of the recommendations included in this Plan, implementing AB 32 is expected to have an overall positive effect on the economy. In addition, implementation of the measures in the Recommended Actions section (Chapter II) will reduce statewide oxides of nitrogen (NOx), volatile organic compounds (VOC) and atmospheric particulate matter (PM) emissions primarily due to reduced fuel consumption, with resulting public health benefits. ARB will also work at the measure-specific level to further maximize the public health benefits that can accompany implementation of greenhouse gas emissions reduction strategies. The following sections provide a summary of the ARB evaluations of the recommended measures included in this Scoping Plan. More detailed information on the evaluations and their results are provided in Appendices G and H.

A. Economic Modeling

To evaluate the economic impacts of the Scoping Plan, ARB compared estimated economic activity under a business-as usual (BAU) case to the results obtained when actions recommended in this Plan are implemented. The BAU case is briefly described below. The estimated costs and savings used as model inputs for individual measures are outlined in Appendix G, and additional documentation on the calculation of those costs and savings is provided in Appendix I. All dollar estimates are in 2007 dollars.

Under the BAU case, Gross State Product (GSP) in California is projected to increase from $1.8 trillion in 2007 to almost $2.6 trillion in 2020. The results of our economic analysis indicate that implementation of the Scoping Plan will have an overall positive net economic benefit for the state. Positive impacts are anticipated primarily because the investments motivated by several measures result in substantial energy savings that more than pay back the cost of the investments at expected future energy prices.

The business-as-usual case is a representation of what the State of the California economy will be in the year 2020 assuming that none of the measures recommended in the Scoping Plan are implemented. While a number of the measures in the plan will be implemented as the result of existing federal or State policies and do not require additional regulatory action resulting from the implementation of AB 32, they are not included in the BAU case to ensure that the economic impacts of all of the measures in the Scoping Plan are fully assessed.

The BAU case is constructed using forecasts from the California Department of Finance, the California Energy Commission, and other sources, and is described in more detail in Appendix G. ARB used a conservative estimate of future petroleum price in this analysis, $89 per barrel of oil in 2020. Aspects of the BAU case are subject to uncertainty, for example, the possibility that future energy prices could deviate from those that are included in the BAU case.

1. Macro-economic Modeling Results

Table 24 summarizes the key findings from the economic modeling. Gross State Product, personal income and employment are shown for 2007 and for two cases for 2020, the BAU case and for implementation of the Scoping Plan. For both the BAU case and the Scoping Plan case, Gross State Product increases by almost $800 billion between 2007 and 2020, personal income grows by 2.8 percent per year from $1.5 trillion in 2007 to $2.1 trillion in 2020, and employment grows by 0.9 percent per year from 16.4 million jobs in 2007 to 18.4 million (BAU) or 18.5 million (Scoping Plan) in 2020. The results consistently show that implementing the Scoping Plan will not only significantly reduce California's greenhouse gas emissions, but will also have a net positive effect on California's economic growth through 2020.

Table 24: Summary of Key Economic Findings from Modeling the Scoping Plan Using E-DRAM

Economic Indicator	2007	Business-as-Usual*		Scoping Plan		
		2020	Average Annual Growth	2020	Change from BAU	Average Annual Growth
Gross State Product ($Billion)	1,811	2,586	2.8%	2,593	0.3%	2.8%
Personal Income ($Billion)	1,464	2,093	2.8%	2,109	0.8%	2.8%
Employment (Million Jobs)	16.41	18.41	0.9%	18.53	0.7%	0.9%
Emissions ($MMTCO_2E$)	500**	596	1.4%**	422	-28%	-1.2%**
Carbon Prices (Dollars)	-	-	-	10.00	NA	-

* Business-as-usual is a forecast of the California economy in 2020 without implementation of any of the measures identified in the Scoping Plan.

** Approximate value. ARB is in currently estimating greenhouse gas emissions for 2007.

The macroeconomic modeling results presented here understate the benefits of market-based policies, including the cap-and-trade program. Consequently, our estimate of the economic impact of implementing the Scoping Plan understates the positive impact on the California economy. Nonetheless, using the current best estimates of the costs and savings of the measures, which are documented in Appendix I, the models demonstrate that implementing the Plan will have a positive effect on California's economy.

The modeling results reflect a carbon price for the cap-and-trade program of $10 per-ton. It is important to note that the $10 per-ton figure does not reflect the average cost of reductions; rather it is the *maximum* price at which reductions to achieve the cap are pursued based on the marketing program.

The positive impacts are largely attributable to savings that result from reductions in expenditures on energy. These savings translate into increased consumer spending on goods and services other than energy. Many of the measures entail more efficient use of energy in the economy, with savings that exceed their costs. In this way, investment in energy efficiency results in money pumped back into local economies. Table 25 summarizes the energy savings that are projected from implementation of the Scoping Plan. These savings are estimated to exceed $20 billion annually by 2020.

Table 25: Fuels and Electricity Saved in 2020 from Implementation of the Scoping Plan

	Gasoline	Diesel	Electricity	Natural Gas*
Use Avoided**	4,600 million gallons	670 million gallons	74,000 GWh	3,400 million therms
Value of Avoided Fuel Use (Million $2007)	$17,000	$2,500	$6,400***	$2,700
Percent Reduction from BAU	25%	17%	22%****	24%

* Not including natural gas for electric generation.

** These estimates are based on reduced use of these fuels due to increased efficiencies, reduced vehicle miles travelled, etc. Changes to the fuel mix, such as those called for under the RPS or the LCFS, are not included here. These estimates are not the same as the estimates of reduced fuel consumption used in the public health analysis.

*** Based on estimated avoided cost based on average base-load electricity, including generation, transmission and distribution.

**** This is as a percentage of BAU total California electricity consumption in 2020.

2. Impact on Specific Business Sectors

As indicated in Table 26 and Table 27, the effects of the Plan are not uniform across sectors. Implementation of the Scoping Plan would have the strongest positive impact on output and employment for the agriculture, forestry and fishing sector, the finance, insurance and real estate sector, and the mining sector. Similar to the statewide economic impacts projected by the model, however, these results also indicate that relative to the business-as-usual case, the impacts due to implementation of the Plan change current growth projections for most sectors by only very small amounts.

Table 26 and Table 27 also show that a decrease in output is projected for the utility and retail trade sectors as compared to the business-as-usual case, and a decrease in employment is projected for the utility sector. In the utility sector, the modeling indicates that implementation of the Scoping Plan would significantly reduce the need for additional power generation and natural gas consumption, which subsequently reduces the growth in output for this sector. This results in a reduction from business-as-usual for economic output and employment of approximately 17 and 15 percent respectively in 2020. The primary reason for these projections is the implementation of efficiency measures and programs for both consumers and producers. While increasing spending on efficiency and renewable energy is expected to increase employment, many of the resulting jobs will not appear in the utility sector.

The retail trade sector, which is projected to grow by nearly 50 percent in both the business-as-usual and the Scoping Plan case, is also projected to experience a slight net decline in output relative to business-as-usual. Since gasoline is considered a consumer retail purchase under this model, the reduced growth is mostly due to the decrease of approximately $19 billion in retail transportation fuel purchases, which is largely offset by the positive $14 billion increase in spending at other retail enterprises.

Table 26: Summary of Economic Output by Sector from Modeling the Scoping Plan Using E-DRAM

Sector	Output ($Billions)			
	2007	**Business-as-Usual**	**Scoping Plan**	**Percent Change from BAU**
Agriculture, Forestry and Fishing	76	109	113	3.9%
Mining	27	29	31	7.2%
Utilities	51	72	60	-16.7%
Construction	114	164	166	1.7%
Manufacturing	673	943	948	0.5%
Wholesale Trade	120	171	173	1.0%
Retail Trade	207	296	291	-1.6%
Transportation and Warehousing	76	109	111	1.9%
Information	164	235	238	1.1%
Finance, Insurance and Real Estate	391	559	572	2.3%
Services	636	910	927	1.9%
Government	-	-	-	-
Total	**2,535**	**3,597**	**3,630**	**0.8%**

Table 27: Summary of Employment Changes by Sector from Modeling the Scoping Plan Using E-DRAM

Sector	Employment (thousands)			
	2007	**Business-as-Usual**	**Scoping Plan**	**Percent Change from BAU**
Agriculture, Forestry and Fishing	398	449	464	3.5%
Mining	26	26	26	1.3%
Utilities	60	67	57	-14.7%
Construction	825	929	934	0.5%
Manufacturing	1,821	2,046	2,057	0.5%
Wholesale Trade	703	791	793	0.1%
Retail Trade	1,688	1,901	1,916	0.8%
Transportation and Warehousing	447	503	510	1.2%
Information	398	448	450	0.4%
Finance, Insurance and Real Estate	911	1,026	1,046	2.0%
Services	5,975	6,729	6,773	0.7%
Government	3,100	3,491	3,502	0.3%
Total	**16,352**	**18,405**	**18,528**	**0.6%**

3. Household Impacts

Implementation of the Scoping Plan will provide low- and middle-income households savings on the order of a few hundred dollars per year in 2020 compared to the business-as-usual case, primarily as a result of increased energy efficiencies.

Low-Income Households: Based on current U.S. Department of Health and Human Services poverty guidelines, we evaluated the projected impacts of the plan on households with earnings at or below both 100 and 200 percent of the poverty guidelines. For all households, including those with incomes at 100 percent and 200 percent of the poverty level, implementation of the Scoping Plan produces a slight increase in per-capita income relative to the business-as-usual case.

At the same time, the analysis projects an increase of approximately 50,000 jobs available for lower-income workers[49] relative to business-as-usual as a result of implementing the Plan. The largest employment gains come in the retail, food service, agriculture, and health care fields. A decline in such jobs is projected in the retail gasoline sector due to the overall projected decrease in output from this sector. This decline, however, is more than offset by the increases experienced in other areas.

Another important factor to consider when analyzing the impact of the Scoping Plan on households is how it will affect household expenditures. As indicated in Table 28, analysis based on the modeling projections estimates a savings (i.e., reduced expenditures) of around $400 per household in 2020 for low-income households under both federal poverty guideline definitions. These savings are driven primarily by the implementation of the clean car standards and energy efficiency measures in the Scoping Plan that over time are projected to outweigh potential increases in electricity and natural gas prices that may occur. As the measures in the Scoping Plan are implemented, ARB will work to ensure that the program is structured so that low income households can fully participate in and benefit from the full range of energy efficiency measures. Many of California's energy efficiency efforts are targeted specifically at low income populations, and the CPUC's Long Term Strategic Plan for energy efficiency has redoubled its objective for the delivery of energy efficiency measures to low income populations. Additional information regarding the data in Table 28 can be found in Appendix G.

[49] Low-income jobs are defined as those with a median hourly wage below $15 per hour (2007 dollars) based on wage data and staffing pattern projections from the California Employment Development Department. The shares of low-wage occupations for each industry are then applied to the corresponding E-DRAM sector employment projections.

Table 28: Impact of Implementation of the Scoping Plan on Total Estimated Household Savings in 2020 (2007 $)

Income at 100% of Poverty Guideline	Income at 200% of Poverty Guideline	Middle Income*	High Income**	All Households***
$400	$400	$500	$500	$500

* All households between 200% and 400% of the poverty guidelines.

** All households above 400% of the poverty guidelines.

*** Average of households of all income levels.

The analysis indicates that implementation of the Scoping Plan is likely to result in small savings for most Californians, with little difference across income levels. Largely due to increased efficiencies, low-income households are projected to be slightly better off from an economic perspective in 2020 as a result of implementing AB 32.

Middle-Income Households: Implementation of the plan produces a small increase in household income across all income levels, including middle-income households, relative to the business-as-usual case.[50] In terms of how jobs for middle-income households[51] would be impacted, the modeling indicates a slight overall increase of almost 40,000 in 2020.

As shown in Table 28, the analysis projects a net-savings in annual household expenditures of about $500 in 2020 for middle-income households. These savings are driven by the emergence of greater energy efficiencies that will be implemented as a result of the plan.

4. WCI Economic Analysis

The Scoping Plan recommends that California develop a cap-and-trade program that links to the broader regional market being developed by the Western Climate Initiative (WCI). In order to examine the economic impacts of WCI program design options, WCI Partner jurisdictions contracted with ICF International and Systematic Solutions, Inc. (SSI) to perform economic analyses using ENERGY 2020, a multi-region, multi-sector energy model. The WCI economic modeling results are reported in full in Appendix D and are discussed in the Background Report on the Design Recommendations for the WCI Regional Cap-and-Trade Program, also included in Appendix D.

To help inform the program design process, the WCI analysis examined the implications of key design decisions, including: program scope, allowance banking,

[50] For purposes of our analysis we define "middle-income" households as those earning between 200% and 400% of the federal poverty guidelines.

[51] Hourly wage between $15 and $30 per hour.

and the use of offsets. Due to time and resource constraints, the modeling was limited to the eight WCI Partner jurisdictions in the Western Electric Coordinating Council (WECC) area, thereby excluding from the analysis three Canadian provinces, Manitoba, Quebec, and Ontario. Future analyses are planned that will integrate these provinces so that a full assessment of the WCI Partner jurisdictions can be performed.

The WCI modeling work is not directly comparable to the ARB results reported here. The WCI analysis relies on a more aggregated set of greenhouse gas emissions reduction measures rather than the specific individual policies recommended in the Scoping Plan; it uses somewhat different assumptions regarding what measures are included in the "business-as-usual" case, and it models the entire WECC rather than California. Nevertheless, the results of the WCI modeling provide useful insight into the economic impact of greenhouse gas emissions reduction policies.

Consistent with the conclusions of the ARB evaluation, overall the WCI analysis found that the WCI Partner jurisdictions can meet the regional goal of reducing emissions to 15 percent below 2005 levels by 2020 (equivalent to the AB 32 2020 target) with small overall savings due to reduced energy expenditures exceeding the direct costs of greenhouse gas emissions reductions. The savings are focused primarily in the residential and commercial sectors, where energy efficiency programs and vehicle standards are expected to have their most significant impacts. Energy-intensive industrial sectors are estimated to have small net costs overall (less than 0.5 percent of output).

The WCI analysis does not examine the potential macroeconomic impacts of the costs and savings estimated with ENERGY 2020. The WCI Partner jurisdictions are planning to continue the analysis so that macroeconomic impacts, such as income, employment, and output, can be assessed. Once completed, the macroeconomic impacts can be compared to previous studies of cap-and-trade programs considered in the United States and Canada.

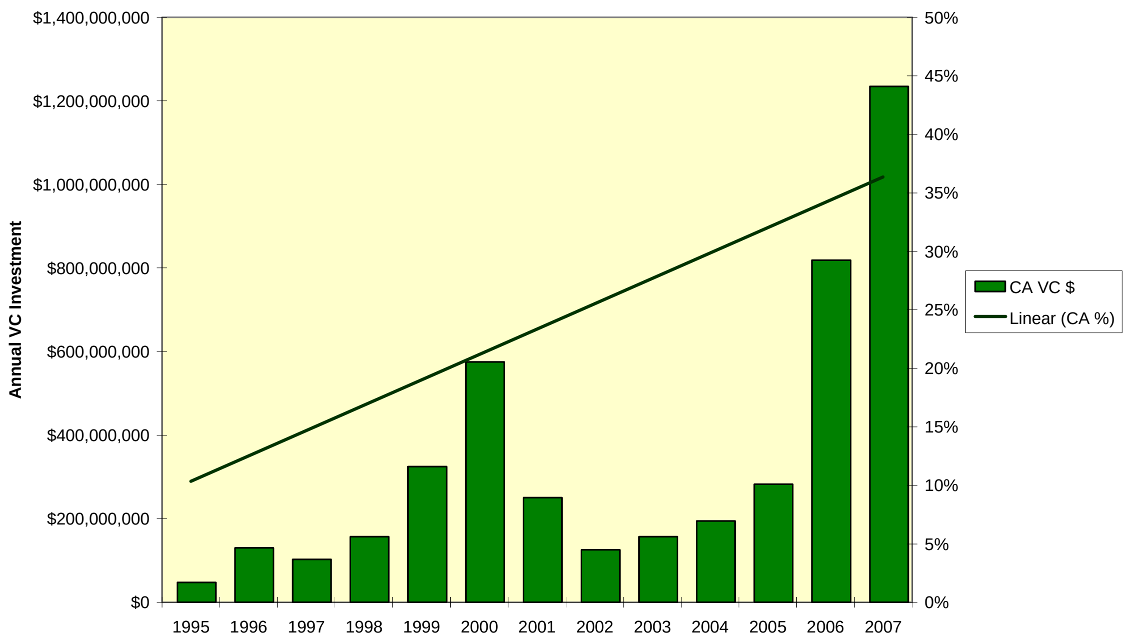
B. Green Technology

The development of green technologies and a trained workforce equipped to design, develop and deploy them will be key to the success of California's long-term efforts to combat global warming. Bold, long-range environmental policies help drive innovation and investment in emission-reducing products and services in part by attracting private capital. Typically, the private sector under invests in research and development for products that yield public benefits. However, when environmental policy is properly designed and sufficiently robust to support a market for such products, private capital is attracted to green technology development as it is to any strategic growth opportunity.

California's leadership in environmental and energy efficiency policy has helped attract an increasing share of venture capital investment in green technologies. According to statistics from PricewaterhouseCoopers and the National Venture Capital Association, California's share of U.S. venture capital investment in innovative energy technologies increased dramatically from 1995 to 2007 (see Figure 5 below).[52] The same period saw a stream of pioneering environmental policy initiatives, including energy efficiency codes for buildings and appliances, a renewables portfolio standard for electricity generation, climate change emissions standards for light-duty automobiles and, most recently, AB 32. Flows of venture capital into California are escalating as a direct result of the focus on reductions of greenhouse gas emissions. As mentioned above, California captured the largest single portion of global venture capital investment ($800 million out a total of two billion dollars) during the second quarter of 2008.

Figure 5

California's Growing Share of Venture Capital Investment in Energy Innovation, 1995-2007 (current $, % share)



Source: PricewaterhouseCoopers MoneyTree Report, available at: [https://www.pwcmoneytree.com].

A survey of clean technology investors by Global Insight and the National Venture Capital Association found that public policy influences where venture capitalists invest.[53] Furthermore, investments in green technology solutions produce jobs at a higher rate than investments in comparable conventional technologies.[54] Venture capitalists estimate that

[52] Based on historical trend data for the 'Industrial/Energy' industry for California and the United States from the PricewaterhouseCoopers MoneyTree Report. https://www.pwcmoneytree.com/MTPublic/ns/nav.jsp?page=historical (accessed October 12, 2008)

[53] Clean Tech Entrepreneurs & Cleantech Venture Network LLC. *Creating Cleantech Clusters: 2006 Update*. May 2006. p.43 http://www.e2.org/ext/doc/2006%20National%20Cleantech%20FORMATTED%20FINAL.pdf (accessed October 12, 2008)

[54] Report of the Renewable and Appropriate Energy Laboratory. *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?* Energy and Resources Group/Goldman School of Public Policy at

each $100 million in venture capital funding, over a period of two decades, helps create 2,700 jobs, $500 million in annual revenues, and many indirect jobs.[55]

Access to capital controlled by institutional investors is also enhanced by policies that encourage early adoption of green technologies. When California-based corporations use green technologies to reduce their exposure to climate change risk, institutional investors reward them by facilitating their access to capital. The Investor Network on Climate Risk – including institutional investors with more than $8 trillion of assets under management – endorsed an action plan in 2008 that calls for requiring asset managers to consider climate risks and opportunities when investing; investing in companies developing and deploying clean technologies; and expanding climate risk scrutiny by investors and analysts.[56]

Additional capital for green technologies helps drive increased employment, both indirectly, as energy savings are plowed back into other sectors of the economy, and directly, as new green products are successfully commercialized.

McKinsey & Company projects average annual returns of 17 percent on global investments in energy productivity, and estimates the global investment opportunity at $170 billion annually through 2020.[57] Meanwhile, global investment in energy efficiency and renewable energy has grown from $33 billion to more than $148 billion in the last four years. Beyond 2020, green technologies are expected to attract investment of more than $600 billion annually.[58] In short, green technology is now a *bona fide* global growth industry.

Today, green technology businesses directly employ at least 43,000 Californians, primarily in energy efficiency and energy generation, according to a 2008 study from the California Economic Strategy Panel. Green jobs are concentrated in manufacturing (41 percent), and professional, scientific and technical services (28 percent), with median annual earnings of

---

University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

[55] Report prepared for the National Venture Capital Association. *Venture Impact 2004: Venture Capital Benefits to the U.S. Economy*. Prepared by: Global Insight. June 2004. http://www.globalinsight.com/publicDownload/genericContent/07-20-04_fullstudy.pdf (accessed October 12, 2008)

[56] The Investor Network on Climate Risk. *Final Report, 2008 Investor Summit on Climate Risk*. February 14, 2008. http://www.ceres.org//Document.Doc?id=331 (accessed October 12, 2008)

[57] McKinsey Global Institute. *The Case for Investing in Energy Productivity.* McKinsey & Company. February, 2008. p.8 http://www.mckinsey.com/mgi/reports/pdfs/Investing_Energy_Productivity/Investing_Energy_Productivity.pdf (accessed October 12, 2008)

[58] United Nations Environment Programme-New Energy Finance Ltd. *Global Trends in Sustainable Energy Investment 2008: Analysis of Trends and Issues in the Financing of Renewable Energy and Energy Efficiency* 2008. p.12 ISBN: 978-92-807-2939-9 http://www.unep.fr/energy/act/fin/sefi/Global_Trends_____2008.pdf (accessed October 12, 2008)

$35,725 and $56,754, respectively.[59] By 2030, under a moderate growth scenario, green businesses nationwide are expected to generate revenues of $2.4 trillion, (2006 dollars), and employ 21 million Americans.[60]

As a leader in green technology development and use, California has already realized substantial economic benefits from the adoption of energy efficiency policies. State energy efficiency measures have saved enough energy over the past 30 years to avoid construction of two dozen 500-megawatt power plants. Today, California's per capita electricity consumption is 40 percent below the national average, and the carbon intensity of California's economy is among the lowest in the nation.[61]

Renewable energy, such as solar, wind, biomass, geothermal, will also bring new employment opportunities to Californians while spurring economic growth. California enjoys significant comparative advantages for renewable energy: concentrated innovation resources, a large potential customer base, key natural resources such as reliable solar and wind, and supportive regulatory programs, including the California Renewables Portfolio Standard, the Million Solar Roofs Initiative, the California Global Warming Solutions Act of 2006, and the Solar Water Heating and Efficiency Act of 2007.

Other researchers have estimated that under a national scenario with 15 percent renewables penetration by 2020, California will experience a net gain in direct employment of 140,000 jobs.[62] Because investments in green technologies produce jobs at a higher rate than investments in conventional technologies, jobs losses that occur in traditional fossil fuel industries will be more than compensated for by gains in the clean energy sector.

Furthermore, if California's renewable energy suppliers field products that are sufficiently competitive to penetrate the export market, employment and earnings dividends for the state will also increase. California renewable energy industries servicing the export market can generate up to 16 times more employment than those that only manufacture for domestic

---

[59] California Economic Strategy Panel with Collaborative Economics. *Clean Technology and the Green Economy*. March 2008. P.14-15 http://www.labor.ca.gov/panel/pdf/DRAFT_Green_Economy_031708.pdf (accessed October 12, 2008)

[60] The American Solar Energy Society. *Renewable Energy and Energy Efficiency: Economic Drivers for the 21st Century*. 2007. p.39 ISBN 978-0-89553-307-3 http://www.ases.org/images/stories/ASES-JobsReport-Final.pdf (accessed October 12, 2008)

[61] California Energy Commission. *2007 Integrated Energy Policy Report*. Document No. CEC-100-2007-008-CMF. 2007. p. 3 http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF (accessed October 12, 2008)

[62] Tellus Institute and MRG Associates. *Clean Energy: Jobs for America's Future*. As cited in: Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate? Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

consumption, according to a study by the Research and Policy Center of Environment California.[63]

C. Cost-Effectiveness

As noted in several provisions of AB 32, cost-effectiveness is an important requirement to be considered in the design and implementation of emission reduction strategies. (See HSC §§38505, 38560, 38561, 38562.) AB 32 defines "cost-effective" or "cost-effectiveness" as "the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential." (HSC §38505(d)) This definition specifies the metric (i.e., dollars per ton) by which the Board must express cost-effectiveness, but it does not provide criteria to assess if a regulation is or is not cost-effective. It also does not specify whether there should be a specific upper-bound dollar per ton cost that can be considered cost-effective, or how such a bound would be determined or adjusted over time. ARB has investigated different approaches that could be used to evaluate the cost-effectiveness of regulations and is recommending the following approach.

The estimated cost per ton of greenhouse gas emissions reduced by the measures recommended in this Plan ranges from $-408 (net savings) to $133, with all but one (the Renewables Portfolio Standard) costing less than $55 per ton. The RPS is being implemented for energy diversity purposes, not just greenhouse gas reductions, and the $133 per ton figure does not take these other benefits into account. Therefore, it should not be used as a reference to define the range of cost-effective greenhouse gas measures. These estimates are based on the best information available as ARB prepared this Plan. Updated estimates and greater certainty will be provided as the measures are further developed during the rulemaking process.

In the meantime, the current estimates provide a range illustrating the cost per ton of the mix of measures that collectively meet the 2020 target. This range will assist the Board in evaluating the cost-effectiveness of individual measures when considering adoption of regulations. The range of acceptable cost-effectiveness may change if effective lower-cost measures and options are identified. Because both the projections of "business-as-usual" 2020 emissions and the degree of reductions from any given measures may be greater or less than current estimates, the determination should remain flexible to accommodate a higher or lower estimate of cost-effectiveness. In addition, the approach must provide flexibility to pursue measures that simultaneously achieve policy objectives other than greenhouse gas emissions reduction (such as energy diversity).

The criteria for judging cost-effectiveness will be updated as additional technological data and strategies become available. As ARB moves from adoption of the Scoping Plan to

[63] Environment California Research and Policy Center. *Renewable Energy and Jobs. Employment Impacts of Developing Markets for Renewables in California*. July 2003. As cited in: Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate? Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

developing specific regulations, and as regulations continue to be adopted, updated cost-effectiveness estimates will be established in a rigorous and transparent process with full stakeholder participation. As ARB progresses from proposed measures and estimated costs to actual regulations, the comparison of cost-effectiveness would move toward the well established practice of comparing the cost-effectiveness of new regulations to the cost-effectiveness of previously enacted and/or similar regulations. This approach is consistent with how cost-effectiveness is evaluated for strategies to reduce criteria and toxic pollutants.

D. Small Business Impact

Small businesses play an important role in California's economy. As required under AB 32, ARB analyzed the impact that implementation of the Scoping Plan would have on small businesses in the state. The analysis indicates that the primary impacts on small businesses as a result of AB 32 will come in the form of changes in the costs of goods and services that they procure, and in particular, changes in energy expenditures. Due to the number of measures in the plan that will deliver significantly greater energy efficiencies, our analysis projects that implementation of the plan will have a positive impact on small business in California even after taking into account the higher per-unit energy prices that are likely to occur between now and 2020. Small businesses also will benefit as a result of the robust economic growth and the increases in jobs, production, and personal income that are projected between now and 2020 as AB 32 is implemented. Additional information is provided in Appendix G.

Recent analysis from Energy and Environmental Economics, Inc. (E3) forecasts that a package of greenhouse gas emissions reduction measures similar to those recommended in this Plan would deliver a five percent decrease in electricity expenditures for the average California electricity customer relative to business-as-usual in 2020.[64] This projection is based on the assumption that increases in electricity prices will be more than offset by the continued expansion of energy efficiency measures and that more efficient technologies will be developed and implemented.[65] For purpose of this analysis, expenditures on natural gas are assumed to remain the same, balancing the projected 29 percent decrease in natural gas consumption in California with the model's projected natural gas price increase of almost 9 percent.

Based on this assessment, implementation of the Scoping Plan will likely have minor but positive impacts on small businesses in the state. These benefits are attributable primarily to the measures in the plan that will deliver significantly greater energy and fuel efficiencies. Even when higher per unit energy prices are taken into account, these efficiencies will decrease overall energy expenditures for small businesses. Additionally, as previously described, the California economy is projected to experience robust economic growth

---

[64] Based on their GHG Calculator, CPUC/CEC GHG Docket (CPUC Rulemaking.06.04.009, CEC Docket 07-OIIP-01), available at http://www.ethree.com/cpuc_ghg_model.html.

[65] The E3 analysis focuses on direct programmatic measures and does not include the incremental price impact of the cap-and-trade program, which will depend upon allowance price, allocation strategy, the capped sector industry response, and other program design decisions.

between now and 2020 as AB 32 is implemented. Small businesses will experience many of the benefits associated with this growth in the form of more jobs, greater production activity, and rising personal income.

The projected decrease in electricity expenditures is especially important for small businesses since they typically spend more on energy as a percentage of revenue compared to larger enterprises. For example, firms with a single employee spend approximately 3.3 percent of each sales dollar on electricity, while businesses with between ten and forty-nine employees spend around 1.2 percent. As a result, smaller businesses are likely to experience a greater relative benefit from decreased energy expenditures relative to their larger counterparts.

From the broader economic perspective, these changes will make California more competitive as a location for small business, moving it from 7th highest to 19th among all states in terms of the percentage of revenue that businesses expend on electricity.[66] As was noted above for low income households, care must be taken to ensure that the program is structured to allow small businesses to participate in and benefit from the energy efficiency measures.

While ARB's analysis indicates a positive impact on small businesses from AB 32 implementation, to ensure that these benefits are realized to the fullest potential it will take additional outreach and communication efforts on the part of ARB and many other state and local entities. There are a number of existing programs that are designed to help small businesses achieve greater efficiencies in energy use. These programs can be enhanced and expanded upon, and new programs and efforts can be developed to ensure that all small businesses in California are aware of and able to take cost-effective steps to reduce energy use and enjoy the associated economic savings. For example, as discussed more completely in Chapter IV, ARB and our partners in State government are working together to develop an on-line small business "toolkit" designed for small and medium-sized businesses to provide a one-stop shop of technical and financial information resources. As further development and implementation of the measures in the plan proceeds, we will work with other state and local partners to ensure that small businesses can both benefit from and play a role in helping to achieve our greenhouse gas emission reduction requirements.

E. Public Health/Environmental Benefits Analyses

AB 32 requires ARB to evaluate the environmental and public health impacts of the Scoping Plan. The analysis of this plan is focused primarily on the quantification of public health benefits from air quality improvements that would result from implementation. Unlike traditional pollutants and toxic emissions, global warming pollutants do not typically have localized impacts. At ambient levels, carbon dioxide, which makes up over 80 percent of global warming pollutants in California, has no direct environmental or public health consequences. Climate change caused by greenhouse gas pollutants emitted in another state

[66] Although the natural gas data is less specific, a similar scenario is expected where increased prices are typically offset by greater efficiencies for most small businesses.

or country has the same potential to damage our public health and the environment as does climate change due to pollutants emitted within California. Although this analysis does not consider the public health impacts of climate change, the potential public health impacts are great, and have been well documented elsewhere. However, many of the measures aimed at reducing global warming pollutants also provide co-benefits to public health and California's natural resources.

The environmental and cumulative impacts of the Plan are discussed in the California Environmental Quality Act (CEQA) document that is included in Appendix J. As the Scoping Plan is implemented, and specific measures are developed, ARB will conduct further CEQA analyses, including cumulative and multi-media impacts. As ARB further develops its approach for consideration of these issues in future rulemakings, and updates needed analytical tools and data sets, we will consult with outside experts and the EJAC. ARB recognizes that the adoption of the Scoping Plan will launch a variety of regulatory proceedings in many different venues. ARB will work closely with other California State agencies including: the Office of Planning and Research, Environmental Protection Agency, Resources Agency, Integrated Waste Management Board, Department of Public Health, Office of Environmental Health Hazard Assessment, State Water Resources Control Board, Department of Toxic Substances Control, Department of Water Resources, Board of Forestry, Department of Fish and Game, Public Utilities Commission, California Energy Commission, and others to identify and address potential multi-media environmental impacts early in the regulatory development process.

California's actions to reduce greenhouse gas emissions will help transition the State to new technologies, improved efficiencies, and land use patterns also necessary to meet air quality standards and other public health goals. California's challenging public health issues associated with air pollution are already the focus of comprehensive regulatory and incentive programs. These programs are reducing smog forming pollutants and toxic diesel particulate matter at a rapid pace. However, to meet increasingly stringent air quality standards and air toxics reduction goals, transformative changes are needed in the 2020 timeframe and beyond. Implementation of AB 32 will provide additional support to existing State efforts devoted to protecting and improving public health.

1. Key Air Quality-Related Public Health Benefits

The primary direct public health benefits of the Scoping Plan are reductions in smog forming emissions and toxic diesel particulate matter. The most significant reductions are of oxides of nitrogen (NOx), which forms both ozone and particulate pollution (PM2.5), and directly emitted PM2.5, which includes diesel particulate matter. The analysis focuses on PM2.5 impacts and quantifies 2020 public health benefits of this plan in terms of avoided premature deaths, hospitalizations, respiratory effects, and lost work days. Additional benefits associated with the reductions in ozone forming emissions were not quantified since statewide 2020 photochemical modeling is not available.

The estimated air quality-related public health benefits of the Scoping Plan are above and beyond the much greater benefits of California's existing programs, which are reducing air pollutant emissions every year. This continuing progress is the result of California's plans for meeting air quality standards ("State Implementation Plans" or SIPs), reducing emissions from goods movement activities, and addressing health risk from diesel particulate matter. These programs address both existing and new sources of air pollution, taking into account population and economic growth. The additional benefits of the Scoping Plan in 2020 are significant, and in the longer term, can be expected to increase with further reductions in fossil fuel combustion, the primary basis for the estimated public health benefits.

The recommended measures in the Scoping Plan that reduce smog forming ("criteria") pollutants are shown in Table 29 along with the estimated reductions. Statewide, these measures would reduce approximately 61 tons per day of NOx and 15 tons per day of PM2.5 in 2020. As shown in Table 30, this equates to an estimated air quality-related public health benefit of 780 avoided premature deaths statewide. In comparison, reductions in PM2.5 from California's existing programs and 2007 SIP measures are estimated to result in 12,000 avoided premature deaths statewide in the same timeframe.

Table 29: Statewide Criteria Pollutant Emission Reductions in 2020 from Proposed Scoping Plan Recommendation[67]

(tons per day)

Measure	NOx	PM2.5
Light-Duty Vehicle • Pavley I and Pavley II GHG Standards • Vehicle Efficiency Measures	1.6	1.4
Goods Movement Efficiency Measures	16.9	0.6
Medium and Heavy-Duty Vehicle GHG Emission Reduction • Aerodynamic Efficiency • Hybridization • Engine Efficiency	5.6	0.2
Local Government Actions and Regional Targets	8.7	1.4
Energy Efficiency and Conservation (Electricity)	7.0	4.0
Energy Efficiency and Conservation (Natural Gas)	10.4	0.8
Solar Water Heating	0.3	0.03
Million Solar Roofs	1.0	0.6
Renewables Portfolio Standard	9.8	5.6
Total	**61**	**15**

[67] Table 29 does not include the criteria pollutant co-benefits of additional greenhouse gas reductions that would be achieved from the proposed cap-and-trade regulation because we cannot predict in which sectors they would be achieved.

Table 30: Estimates of Statewide Air Quality-Related Health Benefits in 2020

Health Endpoint	**Health Benefits of Existing Measures and 2007 SIP** *mean*	**Health Benefits of Recommendations in the Proposed Scoping Plan** *mean*
Avoided Premature Death	12,000	780
Avoided Hospital Admissions for Respiratory Causes	1,300	87
Avoided Hospital Admissions for Cardiovascular Causes	2,600	170
Avoided Asthma and Lower Respiratory Symptoms	190,000	12,000
Avoided Acute Bronchitis	15,000	980
Avoided Work Loss Days	1,200,000	77,000
Avoided Minor Restricted Activity Days	7,000,000	450,000

In addition to the quantified air-quality-related health benefits, our analysis indicates that implementation of the Scoping Plan can deliver other public health benefits as well. These include potential health benefits associated with local and regional transportation-related greenhouse gas targets that can facilitate greater use of alternative modes of transportation, such as walking and bicycling. These types of moderate physical activities reduce many serious health risks including coronary heart disease, diabetes, hypertension and obesity.[68] Finally, it is important to note that the steps California is taking to address global warming, along with actions by other regions, states, and nations, will help mitigate the public health effects of heat waves, more widespread incidence of illness and disease, and other potentially severe impacts.

The measures in the Scoping Plan are designed primarily to help spur the transition to a lower carbon economy. However, in addition to improving air quality, these measures can also improve California's environmental resources, including land, water, and native species. Land resources will be affected by regional transportation-related targets leading to improved land use planning, and forest carbon sequestration targets which can result in better stewardship of California lands and reduced wildfire risk. A number of conservation measures will aid in effective management of the State's precious water resources. Demand for waste disposal and hazardous materials should decrease as measures to encourage recycling and reuse transform our wastes into fuel, energy, and other useful products are implemented. Additional analysis of the way that implementation of the Scoping Plan will impact these environmental resources will be conducted as we proceed. Many of these measures serve the dual purpose of mitigating greenhouse gas emissions and helping California adapt to the impacts of climate change.

[68] Appendix H contains a reference list of studies documenting the public health benefits of alternative transportation.

2. Approach

ARB quantified the potential reductions of NOx and PM2.5 from implementation of the Plan's recommendations, and the public health benefits associated with the resulting potential air quality improvement. These analyses compare NOx and PM2.5 emissions in 2020 with the implementation of the Scoping Plan with NOx and PM2.5 emissions in 2020 in the absence of the Scoping Plan – a "business-as-usual" scenario. The methodology used to evaluate the public health benefits of the emission reductions is similar to the methodology used in ARB's 2006 Goods Movement Emission Reduction Plan (GMERP), as updated in the recent staff report for estimating premature death from exposure to particulate matter.[69] This methodology is based on a peer-reviewed methodology developed by the U.S. Environmental Protection Agency (U.S. EPA). ARB augmented U.S. EPA's methodology by incorporating the result of new epidemiological studies relevant to California's population, including regionally specific studies, as they became available.

AB 32 directs ARB to conduct several levels of analysis as we proceed through the development and implementation of a comprehensive greenhouse gas emissions reduction strategy. As part of the Scoping Plan development, ARB is required to assess both the economic and non-economic impacts of the plan as noted above. Additionally, AB 32 requires ARB to undertake additional analysis at the time of adoption of regulations, including market-based compliance mechanisms.

Although not yet at the stage of regulatory development and adoption, in this analysis ARB conducted an evaluation of the air quality-related public health benefits associated with the Scoping Plan based on a community level emissions analysis example. As regulations that rely on market-based compliance mechanisms are further developed for consideration by the Board, more detail about the specific regulatory proposals will be developed, enabling ARB to more closely evaluate the potential for direct, indirect and cumulative impacts.

3. Existing Programs for Air Quality Improvement in California

The public health analysis of the Scoping Plan presents air-quality benefits that will occur in addition to the benefits of California's comprehensive air quality programs designed to meet health-based standards and reduce health risk from air toxics. It is also important to note that under both a "business-as-usual" scenario and under the implementation of the Scoping Plan, the population and economy of California are projected to continue to grow. New businesses and industries will continue to be sited in California, bringing both economic opportunity and potential environmental impacts. Federal, State, and local laws and regulations have established requirements to ensure that new and modified sources of pollution are carefully evaluated and that

[69] Air Resources Board. *Methodology for Estimating Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California.* October 24, 2008. http://www.arb.ca.gov/research/health/pm-mort/pm-mort_final.pdf (accessed December 9, 2008)

significant impacts are mitigated. Emissions from existing businesses are also tightly controlled by local air pollution control districts. Statewide programs are in place to reduce emissions from cars, trucks, and off-road equipment, along with smog check, cleaner gasoline and diesel fuels, and regulations to reduce evaporative emissions from consumer products, paints, and refueling. Additional information about the existing regulatory framework for sources of air pollution is provided in Appendix H.

It is important to evaluate the air quality and public health benefits of the Scoping Plan in the context of the State's on-going air quality improvement efforts. California's long-standing air pollution control programs have substantially improved air quality in the state and will continue to do so in the future. By 2020, these programs will deliver reductions in statewide NOx emissions of 441 tons per day and direct fine particle emission reductions of 34 tons per day. Through 2020, three key ARB efforts will deliver deep reductions in air pollutant emissions despite continuing growth:

- Diesel Risk Reduction Plan
- Goods Movement Emission Reduction Plan
- 2007 State Implementation Plan

Measures in these plans will result in the accelerated phase-in of cleaner technology for virtually all of California's diesel engine fleets including trucks, buses, construction equipment, and cargo handling equipment at ports. Adoption and implementation of these and other measures are critical to achieving clean air and public health goals statewide.

The U.S. Environmental Protection Agency has set a new, more stringent, national ambient air quality standard for ozone that will have compliance deadlines well past 2020 for the most severely impacted areas like southern California.[70] The unmitigated impacts of climate change will make it harder to meet this standard and to provide healthful air to Californians.

4. Statewide Analysis

For this evaluation, ARB examined the recommended measures to determine the potential for impacts on air, land, water, native species and biological resources, and waste and hazardous materials. Local government, State government, and green building sectors were not included in this evaluation as they represent means of implementation of the greenhouse gas emission reduction measures. As noted, the main focus of this analysis is on air quality. To the extent feasible, ARB quantified estimated emissions reductions in criteria pollutants associated with each recommended measure except cap-and-trade. Reductions in NOx and PM2.5 were

[70] U.S. Environmental Protection Agency. *National Ambient Air Quality Standards for Ozone. Final Rule.* 73 Federal Register 16436. March 27, 2008. http://www.epa.gov/fedrgstr/EPA-AIR/2008/March/Day-27/a5645.pdf (accessed October 12, 2008)

used to estimate public health benefits. The estimated statewide reductions are 61 tons per day of NOx and 15 tons per day of PM2.5. Further analysis of the potential criteria pollutant benefits of a cap-and-trade program will be done as part of regulatory development.

5. Regional Assessment: South Coast Air Basin Example

In order to assess potential air quality benefits of the Scoping Plan on a regional level, ARB evaluated associated criteria pollutant reductions in the South Coast Air Basin as an example case. Existing programs will reduce current NOx emissions by almost 50 percent in 2020. With the new 2007 SIP measures, NOx emissions will be reduced almost 60 percent. Because of the large population and high pollutant concentrations in this region, greater benefits occur from each ton of pollution reduced. The estimated air quality-related public health benefits of the Scoping Plan for the South Coast region are shown in Table 31. The significant air quality-related public health benefits in this region are largely attributed to the additional reductions in PM2.5.

Table 31: Estimated Air Quality-Related Health Benefits of Existing Program, 2007 SIP, and Scoping Plan in the South Coast Air Basin, 2020

Health Impacts / Scenario	Benefits from Existing Program	Additional Benefits from 2007 SIP	Additional Co-Benefits from Scoping Plan
Premature Deaths Avoided	4,800	2,000	360
Hospitalizations Avoided – Respiratory	550	230	40
Hospitalizations Avoided – Cardiovascular	1,100	440	77
Asthma & Lower Respiratory Symptoms Avoided	80,000	35,000	6,200
Acute Bronchitis Avoided	6,400	2,800	500
Work Loss Days Avoided	510,000	220,000	38,000
Minor Restricted Activity Days Avoided	3,000,000	1,300,000	220,000

6. Community Level Assessment: Wilmington Example

ARB also conducted an evaluation of the potential air quality impacts of the Scoping Plan in the community of Wilmington as an illustration of the potential for localized impacts. Wilmington is in southern Los Angeles County and includes a diverse range of stationary and mobile emissions sources, including the ports of Los Angeles and Long Beach, railyards, major transportation corridors, refineries, power plants, and other industrial and commercial operations. Like the regional analysis, additional emission reductions from the 2007 SIP were estimated and show significant reductions in Wilmington by 2020 – approximately a 45 percent reduction in NOx and a 40 percent reduction in directly-emitted PM2.5. Mobile source emissions are projected to continue to be proportionately greater than stationary source emissions in 2020 even as mobile source emissions decline.

For this assessment, ARB evaluated criteria pollutant emission reductions in the Wilmington study area assuming that the source-specific quantified measures are implemented, including measures to reduce emissions from oil and gas extraction and refineries. It was further assumed that the non-source specific program elements, such as the proposed cap-and-trade program, result in a 10 percent reduction in fuel combustion by affected sources within the study area. For example, it is estimated that industrial sources would achieve greenhouse gas emission reductions through efficiency measures that reduce on site fuel use by 10 percent either in response to a cap-and-trade program, or due to the results of the facility energy efficiency audits. While it is likely that the actual onsite reductions will differ across individual facilities from the assumed uniform ten percent reduction,[71] the analysis identifies how reductions at these facilities affect the overall level of co-benefits.

The estimated NOx co-benefit of about 1.7 tons per day is small relative to the projected reductions of 24 tons per day that will occur as a result of the SIP and other measures. For example, an 8 ton per day NOx reduction is expected from cleaner port trucks. In comparison, the potential NOx benefit from a 10 percent efficiency improvement in major goods movement categories is estimated at about 1.5 tons per day. The estimated PM2.5 co-benefits, on the order of 0.12 tons per day, are also small relative to the projected reductions of 2.3 tons per day that will occur as a result of the SIP and other measures. Approximately 30 percent (0.04 ton per day) of the PM 2.5 co-benefit reduction is associated with assumed energy efficiency measures at the four large refineries in the study area, while another 30 percent would occur due to a 10 percent efficiency improvement by goods movement sources.

The co-benefit emissions reductions in the study area would produce regional air quality-related health benefits. A relatively small portion of these benefits would occur in the study area (approximately 300,000 area residents). Health benefits due to reductions in NOx are mostly at the regional levels, since NOx emissions have usually travelled some distance before they are transformed into PM via atmospheric reactions. Point source combustion PM emissions persist in the atmosphere and increase exposures both in the area where they are emitted and broadly throughout the region. Based on previous modeling studies of the impact of port and rail yard PM emissions in the South Coast Air Basin conducted by ARB, PM exposures will be reduced far beyond the study area, and a majority of the health benefits are expected to occur in areas outside of the Wilmington community.[72]

Using the previously described methodology that correlates emission reductions in the air basin with expected regional health benefits there would be an estimated

[71] The reductions at any one facility could be much greater or lesser than 10 percent For example, very small or no reductions might occur because available cost-effective industrial emission reductions have already been implemented at a particular site.

[72] ARB analysis indicates that about 20 percent of the health benefits would occur in the Wilmington area.

24 avoided premature deaths attributed to emission reductions that occur in Wilmington as a result of the Scoping Plan.[73]

F. Summary of Societal Benefits

AB 32 requires ARB to "consider the overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health" (HSC § 38562(b)(6)) when developing regulations to implement the Scoping Plan. ARB conducted an initial assessment of societal benefits associated with AB 32 implementation. This section summarizes those that have been identified during development of the Scoping Plan, including diversification of energy sources, mobility, regressivity, and job creation. More detailed economic and environment/public health analyses can be found in Appendix G and H, respectively. The impact of low income households (regressivity), impacts on small businesses, and impact on jobs are described in the Economic Analysis section and Appendix G.

1. Energy Diversification

Generally, energy-related measures in this Scoping Plan are expected to result in a transformation of the State's energy portfolio, driven primarily by the Low Carbon Fuel Standard (LCFS), which addresses transportation fuel, and the 33 percent RPS, which increases renewably-produced electricity production and distribution to households and businesses.

The LCFS aims to achieve at least a 10 percent reduction in the carbon intensity of California's transportation fuels by 2020. As the State moves toward less dependence upon one source of fuel for transportation, our economy will be less at risk from significant fluctuations in fuel prices. Measures within the Scoping Plan will force energy diversification in California toward low-carbon intensive energy sources and encourage significant growth in infrastructure, capital, and investment in biofuels.

The move toward 33 percent renewables will, by definition, increase the diversification of California's electrical supply. Increased use of wind, solar, geothermal and biomass (including from the organic fraction of municipal solid waste) generation will all add to ensuring the state has a broader portfolio of energy inputs.

Based on ARB's economic analysis, the combined energy diversification and increased energy efficiency expected from implementation of the Scoping Plan is predicted to result in: a 25 percent decrease in gasoline usage (4.6 billion gallons), a 17 percent decrease in diesel fuel use (670 million gallons), a 22 percent decrease in electricity (74,000 GWh reduction) and a 24 percent reduction in natural gas (3,400 therms).

[73] See Appendix H

The cap-and-trade program, offsets, and other measures that contain market-based features may also help diversify California's energy portfolio by incentivizing the development and deployment of clean and efficient energy generating technologies.

2. Mobility and Shifts in Land Use Patterns

Mobility is analyzed through multiple approaches in the Scoping Plan. Appendix C includes an analysis of a proposed measure for regional transportation-related greenhouse targets. Reductions in vehicle miles traveled (VMT) are expected to result from regional and local planning which target land use, building and zoning improvements.

As the Scoping Plan is implemented, measures that support shifts in land use patterns are expected to emphasize compact, low impact growth in urban areas over development in greenfields. Communities could realize benefits, such as improved access to transit, improved jobs-housing balance, preservation of open spaces and agricultural fields, and improved water quality due to decreased runoff. Local and regional strategies promoting appropriate land use patterns could encourage fewer miles traveled, lowering emissions of greenhouse gases, criteria pollutants and PM. More compact communities with improved transit service could increase mobility, allowing residents to easily access work, shopping, childcare, health care and recreational opportunities.

Furthermore, if open spaces and desirable locations become more accessible and communities are designed to encourage walkability between neighborhoods and shopping, entertainment, schools and other destinations, residents are likely to increase their levels of physical activity. Research shows that regular physical activity can reduce health risks, including coronary heart disease, diabetes, hypertension, anxiety and depression, and obesity. Measures in the Scoping Plan encourage Californians to use alternatives to personal vehicle travel that could result in increased personal exercise. To complement these changes, future community developments may evolve to include trails and pedestrian access to major centers. However, where compact development may increase proximity to large sources of pollution, such as high traffic arterials, distribution centers, and industrial facilities, it will be critical to analyze the anticipated and unanticipated impacts and benefits, to ensure that increases in exposure to vehicular air pollution and other toxics and particulates do not occur .

G. California Environmental Quality Act Functional Equivalent Document

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential adverse environmental impacts of proposed projects. ARB's analysis of the potential adverse environmental impacts of the Scoping Plan is presented in Appendix J. The analysis summarizes and discusses the specific strategies in the Scoping Plan that, if adopted and implemented, will reduce greenhouse gas emissions throughout the state. The evaluation is programmatic by necessity; it allows consideration of broad policy alternatives and program-wide mitigation measures at a time when an agency has greater flexibility to deal with basic problems of cumulative impacts. A programmatic document also plays an important role in establishing a structure within which future reviews of related actions can be effectively conducted. The Secretary of California's Resources Agency determined that ARB meets the criteria for a Certified Regulatory Program and requires ARB to prepare a substitute document. This functionally equivalent document (FED) is intended to disclose potential adverse impacts and identify mitigation measures specific to the actions identified in the Scoping Plan. The analysis generally found that the proposed Low Carbon Fuel Standard, Renewables Portfolio Standard and Water measures have the most potential to cause adverse environmental impacts due to the potential for land conversion when projects are undertaken. Additional environmental analysis will be needed when regulations are adopted and at the individual project level to identify mitigation for project specific impacts.

H. Administrative Burden

ARB conducted a assessment of the administrative burden of implementing the Scoping Plan recommendation. (HSC §38562 (b)(7)) The recommendation calls for ARB to develop a cap-and-trade program – a market-based regulatory program to cap and reduce emissions from the Industrial, Electricity, Natural Gas, and Transportation sectors. This program would require stringent monitoring and reporting on the part of the regulated community, and comprehensive enforcement on the part of ARB. Sources under the cap would need to analyze the best approach for their company to comply with a cap – assessing the cost of reducing emissions and comparing that to the cost of purchasing emission reductions in a market. Although ARB has not previously developed this type of market regulation, there is extensive experience to draw upon from within California, nationally, and internationally. In addition, the other regulatory components of the recommendation would require ARB and other State agencies to adopt a series of measures requiring regulatory development, outreach to stakeholders and the public, implementation by industry, and enforcement for numerous measures and programs.

I. De Minimis Emission Threshold

A minimum level at which regulations are determined not to apply is termed the 'de minimis threshold.' In recommending a de minimis level, ARB must take into account the relative contribution of each source or source category to statewide greenhouse gas emissions and the adverse effect on small business. (HSC §38561(e)) This threshold acts as a buffer below which the burden of regulation is determined to outweigh the potential harmful effect of the minimal level of emissions. However, it should not be assumed that an individual source of greenhouse gas emissions that is minimal if taken by itself will fall below the threshold. ARB often looks at the aggregate emissions from a source category or related source category when determining regulatory applicability.

A source category may be evaluated as the aggregate of businesses doing the same type of work (e.g., semiconductor manufacturers), a type of equipment (cargo handling equipment, cars), a process or product (cans of pressurized duster), or other aggregated sources of emissions. Emissions of greenhouse gases from any individual entity within these source categories by themselves could be small. However, when emissions from the source category are evaluated, the relative contribution to climate change can be significant.

As ARB developed the Scoping Plan, potential measures were evaluated against criteria that included the relative contribution of the source to climate change. After this review and considering the level of emissions needed to meet the 1990 target established by AB 32, ARB recommends a de minimis level 0.1 $MMTCO_2E$ annual emissions per source category.[74] Source categories whose total aggregated emissions are below this level are not proposed for emission reduction requirements in the Scoping Plan but may contribute toward the target via other means.

ARB and other agencies implementing measures included in the Scoping Plan should carefully consider this de minimis level in developing regulations, and only regulate smaller source categories if there is a compelling necessity.

As each regulation to implement the Scoping Plan is developed, ARB and other agencies will consider more specific de minimis levels below which the regulatory requirements would not apply. These levels will consider the cost to comply, especially for small businesses, and other factors.

[74] The Forest sector was not included in determining the de minimis level because this sector serves both as a source and a sink for carbon, making the concept of a de minimis level less applicable.

This page intentionally blank.

IV. IMPLEMENTATION: Putting the Plan into Action

Adoption of this Scoping Plan will be a groundbreaking step forward for California. However it is only the beginning of a journey that will last for decades, gradually moving the State into a low-carbon, clean energy future. Putting the Scoping Plan into action will be challenging but with adequate commitment and leadership from Californians up and down the state, it will be a success.

A. Personal Action

The greenhouse gas emission reductions required under AB 32 cannot be realized without the active participation of the people of California. While many of the measures in this Plan must be taken by large sources of emissions, such as power plants and industrial facilities, it is the voluntary commitment and involvement of millions of individuals and households throughout the State that will truly make this California's Plan.

Shifts in individual choices and attitudes drive changes in the economy and in institutions. This dynamic of changing individual behavior will influence California's effort to reduce greenhouse gas emissions. For example, as market forces and environmental awareness encourage more people to drive low-greenhouse gas emitting vehicles, the auto manufacturers will respond with more innovative models and more intensive research. Regulations requiring auto manufacturers to provide these cars will complement the market demand.

This means that thinking about climate change and our carbon footprint will naturally become part of how individuals make decisions about travel, work, and recreation. Some families may choose to purchase a more efficient vehicle when it comes time to replace their current model. Households may choose to lower their thermostat to 68 degrees Fahrenheit during the colder months, and raise it to 78 degrees when air conditioning is required. Some households may choose to swap out incandescent light bulbs for more efficient compact fluorescent lights. Others may choose to install solar water heaters, or arrays of solar electric panels on their roofs to take advantage of renewable energy, and lower their household energy bills. Many households may choose to plant trees to shade and cool their homes, and use landscaping and plants that require less water.

This Plan recommends measures that will help support many of these individual decisions to improve energy efficiency. Statewide measures and regional efforts will result in programs to promote public transportation or riding in carpools, subsidize the purchase of energy efficient appliances, or provide incentives to better insulate and weatherize older homes. ARB is fully committed to assuring California consumers have the widest possible choice of vehicles that emit fewer greenhouse gases than today's models, including the most advanced technology vehicles produced anywhere in the world.

Californians have embraced statewide programs that support positive change in home and business behavior. In less than two decades, separating household waste and recycling at home and work have become commonplace, as has the widespread purchase of appliances with the Energy Star label to save energy. Reducing our carbon footprint by moving toward a cleaner more efficient economy will produce a wide range of benefits to individuals, through lower energy bills and a healthier environment for all.

Conservation can also play a key role. By employing practices to use our resources more sparingly, consumers can both save money and reduce greenhouse gas emissions. On August 18, 2008, Governor Arnold Schwarzenegger launched the EcoDriving program – a comprehensive effort to save consumers money at the gas pump, reduce fuel use and cut CO_2 emissions. By following a set of easy-to-use best practices for driving and vehicle maintenance, a typical EcoDriver can improve mileage by approximately 15 percent. Furthermore, safety is improved when driving speeds are reduced, a key EcoDriving strategy.

Similarly, consumers and businesses can save money and reduce greenhouse gas emissions by conserving resources at homes, offices and commercial buildings. For example, wireless monitor devices to provide instantaneous energy-usage information inside the home are being developed to show users how many kilowatt hours they're consuming at any given moment – as well as how much it's costing them.[75] Providing real-time information on appliance energy use can greatly assist consumers in conserving electricity use.

Many Californians concerned about climate change have also begun to buy carbon offsets to mitigate the impact of their daily activities. These can take various forms, including options that allow consumers to add 'carbon credits' when buying airline tickets, or paying a small monthly charge on utility bills to buy green power. ARB will be working to establish clear rules for voluntary reductions and offsets that might be used for compliance with AB 32. These rules will also help establish clear guidelines for these types of voluntary carbon credit programs and provide California's businesses and consumers greater assurance that money spent on these programs result in real reductions in greenhouse gas emissions.

For more information about how to reduce one's personal carbon footprint, visit www.coolcalifornia.org. This web site provides a carbon footprint calculator and a "top ten" list of ways to save energy at home.

B. Public Outreach and Education

To be successful, a climate action program needs an effective public outreach and education program. The Plan calls for a robust statewide program designed to generate awareness and involvement in California's climate change efforts.

[75] The Sacramento Municipal Utility District (SMUD) is subsidizing PowerCost Monitors to 5,000 customers as a part of a demonstration program. [www.smud.org/residential/saving-energy/monitor.html]

The Climate Action Team will convene a steering team that includes State agencies and other public agencies such as the state's air districts, and public and private utilities, which have a strong track record of successful efforts at public education to reduce driving (Spare the Air) or promote energy efficiency and reduce energy demand. With the release of the California Energy Efficiency Strategic Plan, the CPUC has committed to the launch of a new brand for California Energy Efficiency in 2009, focused on energy efficiency opportunities and coordinated with climate change messaging under AB 32. The steering committee will develop a coordinated array of messages and draw upon a wide range of messengers to deliver them. These will include regional and local governments whose individual outreach campaigns can reinforce the broader State outreach themes while also delivering more targeted messages directly tied to specific local and regional programs.

To ensure that all Californians are included in efforts to address climate change, California will also support highly localized efforts at public education and outreach at the community and neighborhood level. This includes service club organizations and existing faith-based communities – churches, mosques and synagogues. Other private-sector entities including businesses and local chambers of commerce will be invited to partner in spreading the word.

1. Involving the Public and Stakeholders in Measure Development

In keeping with the requirements of AB 32 and the legacy of four decades of regulatory development at ARB, we have worked to make this process fully transparent and will continue to do so as regulations to implement the plan are developed. We will continue our efforts to involve the public to the greatest extent feasible at every stage of the process, including informal and formal rulemaking activities. This will include disadvantaged communities and those with localized concerns, as well as affected industries and small businesses.

Local and community meetings and outreach have been and will continue to be a central element of all rulemaking, with State agencies working closely with disadvantaged communities, EJAC, public health experts, and other stakeholders to fully evaluate the impacts associated with California's greenhouse gas emissions reduction strategies. State agencies involved in measure development will continue to meet periodically with communities to assess any challenges to implementation, or to discover possible new measures or approaches. Stakeholders will be invited to participate in the many additional workshops, workgroups and seminars that will be held as individual measures are developed.

2. Education and Workforce Development

The transition to a clean energy future presents California with a tremendous opportunity to continue growing its green economy and to expand the growth of green job opportunities throughout the state. Making this transition will require a technically educated workforce that is equipped with the skills to develop and deploy 21st century technologies. Investments in training, career technical education, worker transition assistance, and collaboration between public and private partners will be key to ensuring that California fully reaps the economic and job opportunities that will accompany implementation of AB 32.

Setting California on track to a low-carbon future beyond 2020 will be a multi-generational challenge. To meet this challenge, climate-related education in schools must be a central element of California's plan. By 2010, California will develop climate change education components to the State's new K-12 model school curriculum as part of the Education and the Environment Initiative (AB 1548, Pavley, Chapter 665, Statutes of 2003). Expanding the knowledge and opportunities of young people to participate in promoting their own and their communities' environmental health will be an important theme for all these efforts. In the meantime, ARB's educational outreach will continue through the Cool California web pages (www.coolcalifornia.org) and the continued support of student educators through the California Climate Champions programs. ARB will also rely on partners throughout the state to develop and display options for curricula that will enhance the K-12, community college, trade technical training programs, and programs at four-year colleges.

The demand for workers to fill green jobs is rising. There are currently more than 3,000 green businesses in the state, accounting for about 44,000 jobs: 36 percent of these jobs are in professional, scientific, and technical services; 19 percent are in construction; and 15 percent are in manufacturing.[76] Some of these jobs are in new fields, yet many others are simply augmentations of existing skills and vocations such as electrical, construction, machining, auto tech, and heating ventilation and air conditioning. As we move toward 2020, tens of thousands of new green job opportunities will be created.[77] Whether these opportunities come in entirely new fields of employment or in existing areas, it will be critical for California to have a trained workforce available.

Ensuring that California can continue to meet the demand for green jobs will require close coordination between workforce development agencies, businesses, State and local governments, labor unions, and community colleges and universities. Many organizations are already developing strategies and identifying steps to simultaneously meet industry workforce needs and help build a more sustainable economy. For instance, the California Labor and Workforce Development Agency (LWDA) provides a comprehensive range of employment and training services in partnership with State and local agencies and organizations. Similar additional efforts will be crucial in ensuring that the transition to a green economy benefits working

---

[76] California Economic Strategy Panel. *Clean Technology and the Green Economy; Growing Products, Services, Businesses and Jobs in California's Value Network*, Draft, March 2008. http://www.labor.ca.gov/panel/pdf/DRAFT_Green_Economy_031708.pdf

[77] Tellus Institute and MRG Associates. *Clean Energy: Jobs for America's Future.* As cited in: *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?* Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. p. 11 http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf

families in California by providing a steady supply of livable-wage jobs. In the area of energy efficiency, the California Long Term Energy Efficiency Strategic Plan, adopted by the CPUC, details a vision and supporting strategies for the development of a workforce trained and engaged to achieve California's energy-efficiency objectives.

The following strategies will be key to ensure that California's workforce is equipped to help lead the transition to a clean energy future:

- **Strengthen and expand access to Career and Technical Education (CTE) in California public schools for the next generation of workers who will build a green economy.** Over the past several decades, there has been a steady decline in career and technical education. In 2007, less than one-third of all high school students in the state were enrolled in some form of CTE.[78] To take full advantage of the emerging green economy and meet the goals of AB 32, California needs to expand opportunities for CTE in schools. This could include pursuing strategies such as requiring CTE coursework for all middle- and high-school students; increasing the number of CTE credentialed teachers; expanding investment in facilities and equipment for career and technical education; and aligning educational curricula more closely with the skill and workforce needs of the emerging green economy.

- **Ensure an adequate pipeline of skilled workers who are trained in the new technologies of a greener economy.** While some green jobs will be in new businesses and new occupations, most green jobs are variations of traditional occupations in sectors like construction, utilities, manufacturing and transportation.[79] In light of the fact that forty percent of the nation's skilled workers are slated to retire in the next 5 to 10 years,[80] there is an urgent need for educational and training programs to fill these jobs. Strategies to create a steady pipeline of skilled workers include expanding curriculum choices in schools, colleges, and universities to fully reflect career opportunities available in an economy increasingly centered on clean technologies. Other strategies include offering a greater array of industry- and technology-specific courses that would link directly with postsecondary training such as apprenticeship programs, vocational training, or college.

- **Ensure that California's higher education institutions continue to produce the next generation of clean tech engineers, scientists and business leaders.** In addition to providing valuable research on potential climate-change mitigation and adaptation strategies, California's world-class research institutions are the

[78] Get REAL. *Aligning California's Public Education System with the 21st Century Economy Policy Paper for Discussion at Governor Arnold Schwarzenegger's Summit on Career and Technical Education,* March 6, 2007

[79] Ibid.

[80] The New Apollo Program, Clean Energy, Good Jobs: A National Economic Strategy for the New American Century, July 2008. p. 20 http://apolloalliance.org/downloads/fullreportfinal.pdf (accessed October 12, 2008)

incubators for many of the clean tech companies that will contribute to California's environmental and economic future. It will be critical for California to continue to cultivate university research and training programs in a way that takes full advantage of this valuable state resource.

A successful transition to a clean energy future depends heavily on California's ability to provide a well-trained workforce to meet the demands of the growing green economy. ARB and our key partners will continue working throughout the state to ensure that an adequate supply of skilled workers is positioned to take advantage of the growing opportunities for high quality jobs and careers that implementation of AB 32 will bring.

3. Small Businesses

Small businesses play a crucial role in California's economy. As noted in Chapter III, our analysis indicates that this plan will have a net positive impact on small businesses. These impacts are attributable primarily to the measures in the plan that will deliver significantly greater energy and fuel efficiencies. However, as also noted in the analysis, ensuring that these benefits are realized to the fullest potential will require additional outreach and communication efforts by ARB and many other state and local entities.

One of ARB's Early Action measures is designed to help businesses during AB 32 implementation. With our State partners, we are developing an on-line small business "toolkit" designed for small and medium-sized businesses that will provide a one-stop shop for technical and financial resources. Toolkit components will include a business-specific calculator to assess a company's carbon footprint; a voluntary greenhouse gas inventory protocol for measuring greenhouse gas emissions; recommended best practices for energy, transportation, building, purchasing, and recycling; case studies demonstrating how small and medium California businesses have reduced greenhouse gas emissions; program financing resources; peer-networking opportunities; and an awards program to recognize reductions of greenhouse gas emissions among California businesses.

ARB will also continue working with the many business associations, organizations, and other State partners, such as the Small Business Advocate's AB 32 Small Business Task Force, the Labor and Workforce Development Agency, and Business, Transportation, and Housing Agency that have the resources, input and expertise to provide. These partners will help to further develop and implement an effective outreach plan to provide technical assistance to businesses through a variety of means, including attendance at business events, workshops, and working with local economic development agencies.

C. Implementation of the Plan

This Scoping Plan outlines the regulations and other mechanisms needed to reduce greenhouse gas emissions in California. ARB and other State agencies will work closely with stakeholders and the public to develop regulatory measures and other programs to implement the Plan. ARB and other State agencies will develop any regulations in accordance with established rulemaking guidelines. Table 32 shows the status of the proposed measures in the plan.

Table 32: Status of Scoping Plan Measures

Existing Laws, Regulations, Policies And Programs
Light-Duty Vehicle Greenhouse Gas Standards (Pavley I)
Renewables Portfolio Standard (to 20%)
Solar Hot Water Heaters
Million Solar Roofs
High Speed Rail
Measures Strengthening & Expanding Existing Policies & Programs
Electricity Efficiency
Natural Gas Efficiency
Renewables Portfolio Standard (from 20% to 33%)
Sustainable Forests
Light-Duty Vehicle Greenhouse Gas Standards (Pavley II)
Discrete Early Actions
Low Carbon Fuel Standard
High GWP in Consumer Products (Adopted)
Smartways
Landfill Methane Capture
High GWP in Semiconductor Manufacturing
Ship Electrification (Adopted)
SF6 in non-electrical applications
Mobile Air Conditioner Repair Cans
Tire Pressure Program
New Measures
California Cap-and-Trade Program Linked to WCI Partner Jurisdictions
Increase Combined Heat and Power
Regional Transportation-Related GHG Targets
Goods Movement Systemwide Efficiency
Vehicle Efficiency Measures
Medium/Heavy Duty Vehicle Hybridization
High GWP Reductions from Mobile Sources
High GWP Reductions from Stationary Sources
Mitigation Fee on High GWP Gases
Oil and Gas Extraction
Oil and Gas Transmission
Refinery Flares
Removal of Methane Exemption from Existing Refinery Regulations

Rulemakings will take place over the next two years. As with all rulemaking processes, there will be ample opportunity for both informal interaction with technical staff in meetings and workshops, and formal interaction. ARB will consider all information and stakeholder input during the rulemaking process. Based on this information, ARB may modify proposed measures to reflect the status of technological development, the cost of the measure, the cost-effectiveness of the measures and other factors before presenting them to the Board for consideration and adoption.

In addition to these existing approaches, AB 32 imposes other requirements for the rulemaking process. Section 38562(b) explicitly added requirements for any regulations adopted for greenhouse gas emissions reductions. ARB also recognizes the need to expand the scope of analysis required when adopting future greenhouse gas emission reduction regulations. These expanded evaluations include the unique enforcement nature of climate change-related regulations and the possible extended permitting considerations and timelines that must be taken into account when establishing compliance dates. An important consideration in developing regulations will be the potential impact on California businesses. The potential for leakage, the movement of greenhouse gas emissions (and economic activity) out of state, will be carefully evaluated during the regulatory development.

As noted above, as the Scoping Plan is implemented and specific measures are developed, ARB and other implementing agencies will also conduct further CEQA analyses, including cumulative and multi-media impacts. ARB must design equitable regulations that encourage early action, do not disproportionately impact low-income and minority communities, ensure that AB 32 programs complement and do not interfere with the attainment and maintenance of ambient air quality standards, consider overall societal benefits (such as diversification of energy resources), minimize the administrative burden, and minimize the potential for leakage. AB 32 requires that, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emission limit, ARB must consider the potential for direct, indirect and cumulative emission impacts from market-based compliance mechanisms, including localized impacts in communities that are already adversely impacted by air pollution, design the program to prevent any increase in emissions, and maximize additional environmental and economic benefits prior to the inclusion of market-based compliance mechanisms in the regulations. As ARB further develops its approach for consideration of these issues in future rulemakings, and updates needed analytical tools and data sets, we will consult with outside experts and the EJAC.

ARB already conducts robust environmental and environmental justice assessments of our regulatory actions. Many of the requirements in AB 32 overlap with ARB's traditional evaluations. In adopting regulations to implement the measures recommended in the Scoping Plan, or including in the regulations the use of market-based compliance mechanisms to comply with the regulations, ARB will ensure that the measures have undergone the aforementioned screenings and meet the requirements established in HSC §38562 (b) (1-9) and §38570 (b) (1-3).

D. Tracking and Measuring Progress

Many State agencies, working with the diverse set of greenhouse gas emissions sources, have collaborated in the process of developing the strategies presented in this plan. As the agency responsible for ensuring that AB 32 requirements are met, ARB must track the regulations adopted and other actions taken by both ARB and other State agencies as the plan is implemented.

The emissions reductions enumerated in this plan are estimates that may be modified based on additional information. As the proposed measures are developed over the coming years, it is possible that some of these strategies will not develop as originally thought or not be technologically feasible or cost-effective at the level given in the plan. It is equally likely that new technologies and strategies will emerge after the initial adoption schedule required in AB 32, that is, regulation adoption by January 1, 2011. If promising new tools or strategies emerge, ARB and other affected State agencies will evaluate how to incorporate the new measures into the AB 32 program. In this way, new strategies ensuring that the commitments in the plan remain whole and that the 2020 goal can be met will be incorporated into the State strategy.

ARB will update the plan at least once every five years (HSC §38561(h)). These updates will allow ARB to evaluate the progress made toward the State's greenhouse gas emission reduction goals and correct the Plan's course where necessary. This section discusses the tracking and measurement of progress that ARB envisions. The Report Cards and audits, along with an evaluation of new technologies – both emerging and those recently incorporated into the Plan – will also provide valuable input into ARB's update process. Continuous atmospheric monitoring of greenhouse gases may also be useful for determining the effectiveness of emission reduction strategies and for future inventory development.

1. Report Card

SB 85 (Budget Committee, Chapter 178, Statutes of 2007) requires every State agency to prepare an annual "Report Card," detailing measures the agency has adopted and taken to reduce greenhouse gas emissions, including the actual emissions reduced as a result of those actions. The information must be submitted to CalEPA, which is then required to compile all the State agency data into a report format, which is made available on the Internet and submitted to the Legislature. The information allows comparisons of each agency's projected and actual greenhouse gas emissions reductions with the targets established by the CAT or the Scoping Plan. This would be the State's 'Report Card' on its efforts to reduce greenhouse gas emissions.

Agencies are also required, as funds are available, to have an outside audit of greenhouse gas-related actions completed every three years to verify actual and projected reductions.

2. Tracking Progress by Implementing Agencies

As the lead agency responsible for implementing AB 32, ARB must track the progress of both our efforts and the efforts of our partners in implementing their respective provisions of this plan. Communication between ARB and the other implementing agencies will be especially important as regulations and programs are developed. In support of the Report Card requirement noted above, ARB will work with CalEPA to develop a process to track and report on progress toward the plan's goals and commitments.

3. Progress Toward the State Government Target

The CAT recently established a State Government Subgroup to work with State agencies to create a statewide approach to meet the Scoping Plan's commitment to reduce greenhouse gas emissions by a minimum of 30 percent by 2020 below the State's estimated business-as-usual emissions – approximately a 15 percent reduction from current levels. State agencies must lead by example by doing their part to reduce emissions and employ practices that can also be transferred to the private sector. The statewide plan will serve as a guide for State agencies to achieve realistic, measurable objectives within specific timelines. This newly created State Government Subgroup will assist State agencies through these steps in a timely manner.

4. Mandatory Reporting Regulation

ARB's mandatory reporting rule, adopted in December 2007, will help the State obtain facility-level data from the largest sources of greenhouse gas emissions in California. This data will help ARB better understand these sources to develop the proposed emissions reduction measures outlined in this plan.

The regulation requires annual reporting from the largest facilities in the state, accounting for 94 percent of greenhouse gas emissions from industrial and commercial stationary sources in California. There are approximately 800 separate sources that fall under the new reporting rules, which include electricity generating facilities, electricity retail providers and power marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 tons of carbon dioxide each year from on-site stationary source combustions such as large furnaces. This last category includes a diverse range of facilities such as food processing, glass container manufacturers, oil and gas production, and mineral processing.

Affected facilities will begin tracking their greenhouse gas emissions in 2008, to be reported beginning in 2009 with a phase-in process to allow facilities to develop reporting systems and train personnel in data collection. Emissions for 2008 may be based on best available data. Beginning in 2010, emissions reports will be more rigorous and will be subject to third-party verification. Reported emissions data will allow ARB to improve its facility-based emissions inventory data. Originally, the statewide greenhouse gas inventory was based on aggregated sector data and could not be broken down to the facility level. The facility-level reporting required under the Mandatory Reporting regulation will improve data on greenhouse gas emissions for individual facilities and their emitting processes. This information could also help improve emissions inventories for criteria pollutants, and provide additional data for assessing cumulative emission impacts on a community level.

ARB emissions reporting requirements are expected to be modified over time as AB 32 is implemented.

E. Enforcement

Enforcement is a critical component of all of the State's regulatory programs, both to ensure that emissions are actually reduced and to provide a level playing field for entities complying with the law. To meet the 2020 target this plan calls for aggressive action by a number of State agencies. Each of those agencies will employ its full range of compliance and enforcement options to ensure that planned reductions are achieved. The remainder of this section discusses ARB's portion of the enforcement program in more detail.

ARB has an extensive and effective enforcement program covering a wide variety of regulated sources, from heavy-duty vehicle idling, to consumer products, to fuel standards and off-road equipment. To increase the effectiveness of its enforcement efforts and provide greater assurance of compliance, ARB also partners with local, State and federal agencies to carry out inspections and, when necessary, prosecute violators.

ARB will continue its strong enforcement presence as the State's primary air pollution control agency. A critical function of this responsibility is to ensure that all enforcement actions are timely, effective, and appropriate with the severity of the situation. ARB will also continue its close working relationship with local air districts in the development and enforcement of applicable regulations contained within the Scoping Plan and collaborate with the appropriate State agencies on greenhouse gas emission reductions measures.

For the stationary source regulations called for in the plan, ARB will work closely with the local air districts that have primary responsibility for implementing and enforcing criteria pollutant regulations. Not only are local air districts familiar with the individual facilities and their compliance history, but information contained in district permits can be used to verify the accuracy of greenhouse gas emissions reported by sources subject to ARB mandatory reporting requirements. Using this data, regulators can also examine any correlation between greenhouse gases and toxic or criteria air pollutants as a result of emissions trading or direct regulations.

ARB will also continue to partner with the California Highway Patrol and other State and local enforcement agencies on mobile source and other laws and regulations where joint enforcement authorities apply.

Although many of the measures in the Scoping Plan are modeled on existing ARB regulations, a multi-sector, regional cap-and-trade program would bring unique enforcement challenges. ARB and CalEPA have begun the process of engaging and consulting with other State agencies, such as California's Department of Justice, Public Utilities Commission, Energy Commission, as well as the Independent System Operator, on market tracking and enforcement. These working group meetings are ongoing and will culminate in a comprehensive enforcement plan to accompany the proposed cap-and-trade program when the Board considers regulatory requirements. This enforcement plan would describe the administrative structures needed for market monitoring, prosecution, and penalty setting. Public input regarding these issues would also be a key part of the public stakeholder process conducted during development of the cap-and-trade programs regulations.

Accurate measurement and reporting of all emissions would be necessary to assure accountability, establish the integrity of allowances, and provide sufficient transparency to sustain confidence in the market. To ensure compliance, ARB would administer penalties for entities that hold an insufficient quantity of allowances to cover their emissions or fail to report their greenhouse gas emissions. Missed compliance deadlines would also result in the application of stringent administrative, civil, or criminal penalties.

This plan recommends that California implement a cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system. This system would require California to formalize enforcement agreements with its WCI partner jurisdictions for all phases of cap-and-trade program operations, including verification of emissions, certification of offsets based on common protocols, and detection of and punishment for non-compliance. As needed, California would also work with federal regulatory and enforcement agencies that oversee trading markets, such as the Commodity Futures Trading Commission and the Federal Energy Regulatory Commission. While California would work with other jurisdictions on joint enforcement activities, ARB will exercise all of its authority under HSC §38580 and other provisions of law to enforce its regulations against any violator wherever they may be.

F. State and Local Permitting Considerations

Some of the proposed emissions reduction strategies in this Scoping Plan may require affected entities to modify or obtain state or local permits. California's existing permit process ensures that health and safety concerns are evaluated, met, and when appropriate, mitigated. The State recognizes the potential for conflicts between various federal, state and local permitting requirements, which may cross various media – air, water, etc. CalEPA is actively involved in identifying and addressing these regulatory overlap issues with the ultimate goal of consolidating permits where feasible while maintaining all permit requirements. Two such examples are CalEPA's digester permit working group and the CalEPA-Air District Compost Emissions Work Group.

ARB recognizes that the permitting process may affect the viability of certain strategies and that the length of the permitting process could affect the timing of emissions reductions.

ARB, along with CalEPA and other State agencies, will continue to evaluate steps to ensure that permit requirements harmonize across the affected media.

This Plan has been developed with an understanding of the important cross-media impacts. These efforts will continue during the implementation of the Plan. Particular focus on the potential permitting impacts and cross-media consequences of a proposed rule will take place during the rulemaking process.

G. Role of Local Air Districts

Local air districts are ARB's partners in addressing air pollution. ARB takes primary responsibility for transportation, off-road equipment and consumer products. Local districts lead in controlling industrial, commercial and other stationary sources of air emissions. AB 32 recognizes the need to develop a program that meshes with local and regional activities. Although AB 32 does not provide an explicit role for air districts, their local presence as advocates for clean air and their resources, experience and expertise in regulating and enforcing rules for stationary sources make them a logical choice to have an important role in several aspects of implementing California's greenhouse gas program. ARB would partner with local air districts to develop and effectively enforce both source-specific requirements on industrial sources, and to enforce related programs, such as the high GWP rules, that affect a large number of local businesses.

ARB and local air districts are also actively working to coordinate emission reporting requirements. Some districts, like the South Coast Air Quality Management District, have developed software to allow their industrial sources to simultaneously report their criteria pollutant emissions to the District and their greenhouse gas emissions to ARB. Many air district staff are being trained as third-party verifiers to confirm the greenhouse gas emissions information provided by industrial sources under the mandatory reporting regulation, and, similarly, could provide verification of voluntary greenhouse gas reductions in the future.

Local air districts will be key in both encouraging greenhouse gas emissions reductions from other regional and local government entities, and providing technical assistance to quantify and verify those reductions. Local agencies are an important component of ARB's outreach strategy.

Many local air districts have already taken a leadership role in addressing greenhouse gas emissions in their communities. These efforts are intended to encourage early voluntary reductions. For example, local districts are "lead agencies" under the California Environmental Quality Act (CEQA) for some projects. In order to ensure high-quality mitigation projects, some districts have established programs to encourage local greenhouse gas reductions that could be used as CEQA mitigation. As the State begins to institutionalize mechanisms to generate and verify greenhouse gas emissions reductions, ARB and the districts must work together to smoothly transition to a cohesive statewide program with consistent technical standards.

H. Program Funding

Administration, implementation, and enforcement of the emissions reduction measures contained in the Scoping Plan will require a stable and continuing source of funding. AB 32 authorizes ARB to collect fees to fund implementation of the statute. ARB recently initiated a rulemaking for a fee program to fund administration of the program.

Approximately $36 million per year will be needed on an ongoing basis to fund implementation by ARB and other State agencies, based on the positions and funding included in the 2009-2010 fiscal year budget. Additional revenues are needed to repay the loans from State funds that were used to pay ARB and CalEPA expenses in the startup of the program. ARB is moving on an expedited schedule to develop a fee regulation and expects to take a regulation to the Board in mid 2009, with the aim of beginning to collect fees in the 2009/2010 fiscal year.

V. A VISION FOR THE FUTURE

California has the know-how, ingenuity, research capabilities, and culture of innovation to meet the challenge of addressing climate change. However, reaching the goals we have set for ourselves will not be easy. Successful implementation of many of the proposed programs and measures described in this plan will require strong leadership and a shared understanding of the need to reach viable and lasting solutions quickly.

This challenge will also require establishing a wide range of partnerships, both within California and beyond our borders. We will need to support additional research, and further develop our culture of innovation and technological invention. In order to continue the momentum and the commitment to a clean energy future, we will need to both build on existing solutions and develop new ones.

The following sections lay out some of the elements that will be necessary to forge a broad-based institutional strategy to address climate change both within California and beyond. Also discussed is the need to build partnerships on the regional, national and international levels to ensure that our actions complement and support those being taken on a global scale. This section also looks forward to 2030, showing that California is on the trajectory needed to do our part to stabilize global climate.

A. Collaboration

1. Working Closely with Key Partners

True climate change mitigation will require many parties to work together for a global mitigation plan. California and other states are filling a vacuum created by the current lack of leadership at the federal level. By its bold actions, California is moving the United States closer to a seat at the table among the developed countries that have agreed to reduce their carbon emissions, and lead a new international effort for an agreement to replace the Kyoto Protocol that expires in 2012.

Any national climate program must be built on a partnership with State and local governments to ensure that states can continue their role as incubators of climate change policy and can implement effective programs such as vehicle standards, energy efficiency programs, green building codes, and alternative fuel development.

California will work for climate solutions with key federal agencies, including the U.S. Department of Energy and their national labs, the U.S. Environmental Protection Agency, the U.S. Bureau of Land Management, the U.S. Department of Agriculture, the U.S. Department of Transportation, and others.

Through the Western Climate Initiative and in collaboration with other regional alliances of states, California can promote its own best practices and learn from others while helping to formulate the structure of a regional and ultimately national cap-and-trade program.

2. International

As one of the largest economies in the world, California is committed to working at the international level to reduce global greenhouse gas emissions. As part of this effort, Governor Schwarzenegger and other U.S. governors taking the lead in climate change are co-hosting a Global Climate Summit on Finding Solutions Through Regional and Global Action. This summit, held on November 18th and 19th, 2008, began a state-province partnership with leaders from the U.S., Australia, Brazil, Canada, China, India, Indonesia, Mexico, the European Union, and other nations, taking urgent steps to contain global climate change and jointly setting forth a blueprint for the next global agreement on climate change solutions.

California is also a charter member of the International Carbon Action Partnership (ICAP), an organization composed of countries and regions that have adopted carbon caps and that are actively pursuing the implementation of carbon markets through mandatory cap-and-trade systems. California's continued involvement in ICAP will be very beneficial for sharing experiences and knowledge as we design our own market program.

In addition to participating in ICAP, California hopes to engage developing countries to pursue a low-carbon development path. With developing nations expected to suffer the most from the effects of climate change, California and others have an obligation to share information and resources on cost-effective technologies and approaches for mitigating both emissions and future impacts as changes in climate and the environment occur.

California recognizes the "common but differentiated responsibilities" among developed and developing countries (as articulated in the Kyoto Protocol), but the reality is that rapidly escalating greenhouse gas emissions in developing countries could possibly negate any efforts undertaken in California. To the extent that we are part of the global economy, California's demand for goods manufactured in developing countries further exacerbates growth of greenhouse gas emissions globally. Therefore, it is critical for California to help support the adoption of low-carbon technologies and sustainable development in the developing world.

California can advance the international policy debate through state-provincial partnerships for achieving early climate action in developing countries. This approach envisions commitments by developed countries to provide capacity building through technological assistance and investment support in return for developing countries adopting enhanced mitigation actions. California will consider working with developing countries or provinces that have, at a minimum, pledged to achieve greenhouse gas intensity targets in certain carbon-intensive sectors through mechanisms, such as minimum performance standards or sector benchmarks. California also recognizes that developing countries have the challenge and responsibility to reduce domestic emissions in a way that will promote sustainable development, but not undermine their economic growth.

One possible manifestation of these collaborations could be the establishment of sectoral agreements that help to grow developing countries' economies in a low-carbon manner. In a sectoral approach, energy-intensive sectors adopt programs for reducing greenhouse gas emissions and/or energy use. Such sector-based approaches seem likely to win the support of developing countries and could also reduce concerns in developed countries about international competitiveness and carbon leakage.

A state-provincial partnership related to imported commodities (such as cement) would enable California to provide incentives to reduce greenhouse gas emissions associated with products that are imported by our state. California should continue to develop current relations and existing partnership arrangements with China – now the largest emitter of greenhouse gases in the world – because in addition to other compelling reasons much of the state's imported cement originates in China. California should also work to establish similar relations with India and other countries to share research on both greenhouse gas mitigation and climate change adaptation activities. Projects in the Mexican border region may also be of particular interest, considering the opportunity to realize considerable co-benefits on both sides of the border.

Deforestation accounts for approximately 20 percent of global greenhouse gas emissions. California has set a strong precedent in the effort to incorporate forest management and conservation into climate policy by adopting the CCAR forest methodology in October 2007. California also hopes to engage developing countries, including Brazil and Indonesia, to reduce emissions and sequester carbon through eligible forest carbon activities. Activities aimed at Reducing Emissions from Deforestation and Forest Degradation (REDD) were excluded from the rules governing the first Kyoto commitment period, but there is considerable momentum behind the effort to include provisions that would recognize such activities in a post-2012 international agreement. Providing incentives to developing countries to help cut emissions by preserving standing forests, and to sequester additional carbon through the restoration and reforestation of degraded lands and forests and improved forest management practices, will be crucial in bringing those countries into the global climate protection effort. California recognizes the importance of establishing mechanisms that will facilitate global partnerships and sustainable financing mechanisms to support eligible forest carbon activities in the developing world.

B. Research

1. Unleash the Potential of California's Universities and Private Sector

Bringing greenhouse gas emissions down to a level that will allow the climate to stabilize will take a generation or longer. Many of the ultimate solutions to achieve stabilization will be developed and implemented well into the future. Innovation in energy and climate will come from people who are now in school. These young people will face unprecedented challenges, and they will need both wisdom and imagination to craft solutions. California's respected public and private academic institutions must continue to develop and fund programs based on climate change science that cut across disciplines to address the multi-dimensional aspects of climate change.

2. Public-Private Partnerships

To most effectively address the climate change dilemma, we must encourage collaborations between academia and the private sector. Industry is well-positioned to quickly attack problems. Combining the vast knowledge housed in universities with businesses' acumen and agility can unleash a powerful collaborative force to tackle the problems associated with climate change.

Several important programs have already been initiated at California universities, including Stanford's Global Climate and Energy Project and the University of California at Berkeley's Energy Biosciences Institute (EBI).[81] These and other efforts need to be recognized and encouraged, along with others that can link the results of research directly to policy decisions that the State must make.

Carbon Sequestration

In addition to terrestrial carbon sequestration or natural carbon sinks, such as forests and soil, CO_2 can be prevented from entering the atmosphere through carbon capture and storage (CCS). This consists of separating CO_2 from industrial and energy-related sources and transporting the CO_2 to a storage location for long-term isolation from the atmosphere. Potential technical storage methods include geological storage, industrial fixation of CO_2 into inorganic carbonates, and other strategies. Large point sources of CO_2 that may pursue CCS include large power plants, fossil fuel-based hydrogen production plants, and oil refineries.[82]

---

[81] The EBI is being developed in cooperation with Lawrence Berkeley National Laboratory, the University of Illinois at Urbana-Champaign and BP.

[82] Intergovernmental Panel on Climate Change. *Carbon Dioxide Capture and Storage: A Special Report of Working Group III of the IPCC.* Cambridge University Press, UK; 2005. http://www.ipcc.ch/ipccreports/srccs.htm (accessed October 12, 2008)

According to a 2005 report by the Intergovernmental Panel for Climate Change (IPCC), a power plant with CCS could reduce CO_2 emissions to the atmosphere by approximately 80 to 90 percent compared to a plant without CCS (including the energy used to capture, compress and transport CO_2).[83] While more research and development needs to occur, California should both support near-term advancement of the technology and ensure that an adequate framework is in place to provide credit for CCS projects when appropriate.

The State is currently an active member of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), a public-private collaboration to characterize regional carbon sequestration opportunities in seven western states and one Canadian province. Established in 2003, this research project is comprised of more than 80 public and private organizations. WESTCARB is conducting technology validation field tests, identifying major sources of CO_2 in its territory, assessing the status and cost of technologies for separating CO_2 from process and exhaust gases, and determining the potential for storing captured CO_2 in secure geologic formations.[84]

C. Reducing California's Emissions Further – A Look Forward to 2030

In order to assess whether implementing this plan achieves the State's long-term climate goals, we must look beyond 2020 to see whether the emissions reduction measures set California on the trajectory needed to do our part to stabilize global climate.

Governor Schwarzenegger's Executive Order S-3-05 calls for an 80 percent reduction below 1990 greenhouse gas emission levels by 2050. This results in a 2050 target of about 85 $MMTCO_2E$ (total emissions), as compared to the 1990 level (also the 2020 target) of 427 $MMTCO_2E$. Climate scientists tell us that the 2050 target represents the level of greenhouse gas emissions that advanced economies must reach if the climate is to be stabilized in the latter half of the 21st century. Full implementation of the Scoping Plan will put California on a path toward these required long-term reductions. Just as importantly, it will put into place many of the measures needed to keep us on that path.

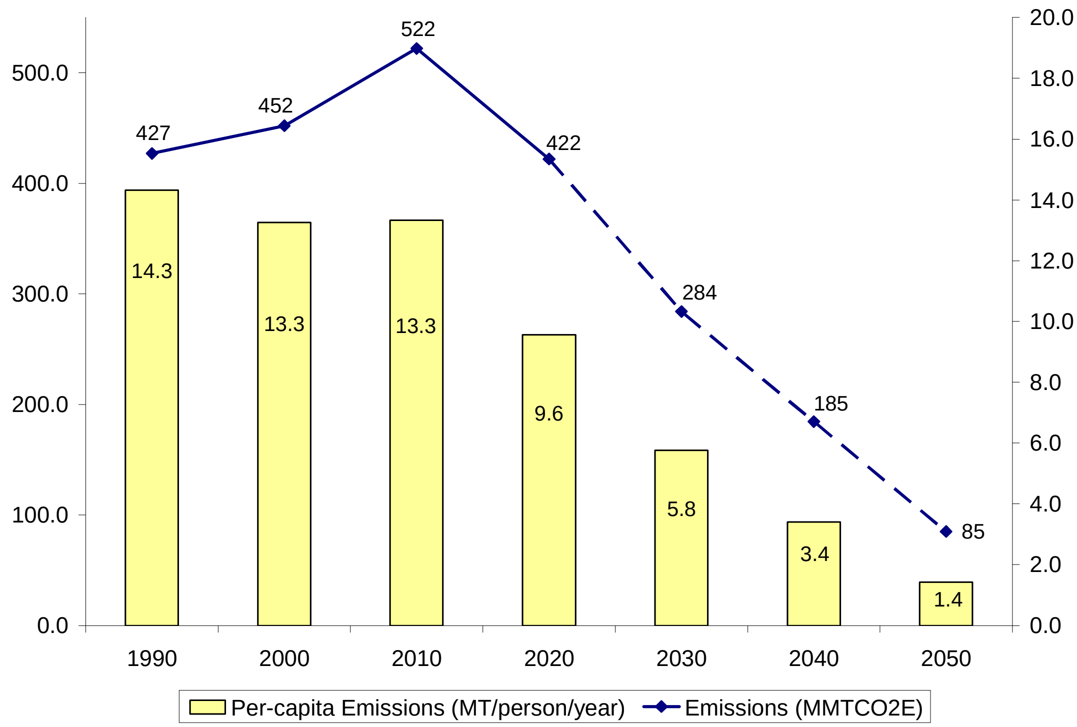
Figure 6 depicts what an emissions trajectory might look like, assuming California follows a linear path from the 2020 AB 32 emissions target to the 2050 goal needed to help stabilize climate. While the measures needed to meet the 2050 goal are too far in the future to define in detail, we can examine the policies needed to keep us on track through at least 2030.

---

[83] Ibid

[84] WESTCARB. *WESTCARB Overview.* http://www.westcarb.org/about_overview.htm (accessed October 12, 2008)

Figure 6: Emissions Trajectory Toward 2050



To stay on course toward the 2050 target our State's greenhouse gas emissions need to be reduced to below 300 $MMTCO_2E$ by 2030. This translates to an average reduction of four percent per year between 2020 and 2030. An additional challenge comes from the fact that California's population is expected to grow by about 12 percent between 2020 and 2030. To counteract this trend, per-capita emissions must decrease at an average rate of slightly less than five percent per year during the 2020 to 2030 period.

Are such reductions possible by 2030? What measures might be able to provide the needed reductions? How do the needed measures relate to the efforts put into place to reach the 2020 goal? All of these are critical questions, and are addressed below.

The answer to the first question is yes, the reductions are possible. Furthermore, the measures needed are logical expansions of the programs recommended in the Scoping Plan that get us to the 2020 goal. We could keep on track through 2030 by extending those programs in the following ways:

- Using a regional or national cap-and-trade system to further limit emissions from the 85 percent of greenhouse gas emissions in capped sectors (Transportation Fuels and other fuel use, Electricity, Residential/Commercial Natural Gas, and Industry). By 2030 a comprehensive cap-and-trade program could lower emissions in the capped sectors from 365 $MMTCO_2E$ in 2020 to around 250 $MMTCO_2E$ in 2030;

- Achieving a 40 percent fleet-wide passenger vehicle reduction by 2030, approximately double the almost 20 percent expected in 2020;
- Increasing California's use of renewable energy;
- Reducing the carbon intensity of transportation fuels by 25 percent (a further decrease from the 10 percent level set for 2020);
- Increasing energy efficiency and green building efforts so that the savings achieved in the 2020 to 2030 timeframe are approximately double those accomplished in 2020; and
- Continuing to implement sound land use and transportation policies to lower VMT and shift travel modes.

The effects of these strategies are presented in Table 33.

Table 33: Potential Distribution of California Greenhouse Gas Emissions by Sector in 2030

Sector	Potential Emissions ($MMTCO_2E$)
Transportation Fuels*	102
Other Fuel Use*	149
Uncapped Sectors	33
Total	**284**

* Capped sector

With these polices and measures in place, per-capita electricity consumption would decrease by another five percent. Well over half of our electricity demand could be met with zero or near zero greenhouse gas emitting technologies, assuming nuclear and large hydro power holds constant at present-day levels. In response to a lower cap on emissions, existing coal generation contracts would not be renewed, or carbon capture and storage would be utilized to minimize emissions. The remaining electricity generation would come from natural gas combustion either in cogeneration applications or from highly efficient generating units.

By 2030, the transportation sector would undergo a similarly massive transition both in terms of the vehicle fleet and the diversity of fuel supplies. Due to the combination of California's clean car standards (ARB's ZEV program and the Low Carbon Fuel Standard), the number of battery-electric vehicles, plug-in hybrid electric vehicles, and fuel cell vehicles would increase dramatically, to about a third of the vehicle fleet. Flex-fuel vehicles would comprise a large fraction of the remaining fleet, with more efficient gasoline and diesel vehicles making up the difference. Electricity, advanced biofuels, improved gasoline and diesel, renewable natural gas and hydrogen would all play a role in powering this high-tech fleet of efficient vehicles.

Regional land use and transportation strategies would grow in importance and would reverse the trend of per-capita vehicle miles traveled, a reduction of about eight percent below business-as-usual in 2030. With ambitious but reasonable action, statewide passenger vehicle greenhouse gas emissions could be reduced to half of 2020 levels in 2030, which is also about half of business-as-usual for 2030. Efficiency strategies and low carbon fuels for heavy-duty and off-road vehicles, as well as for ships, rail, and aviation, would need to be greatly expanded in order to achieve additional reductions from the transportation sector in 2030.

In tandem with efficiency measures that lower demand for electricity, natural gas and transportation fuels, California's cap-and-trade program would incent large industrial sources as well as commercial and residential natural gas customers to further reduce emissions. By tightening the cap over time, it is expected that facilities in the industrial and natural gas sectors would achieve reductions well beyond those needed to meet the 2020 emissions cap.

The Scoping Plan proposes several measures for reducing high GWP gases that collectively, will substantially reduce emissions. With a transition toward reduced consumption of these gases, improved containment in their end uses, and substitution of low GWP alternative gases, it is expected that emissions from this sector could decrease by 75 percent between 2020 and 2030.

For uncapped sectors, we assume that the agriculture sector will reduce emissions by about 15 percent between 2020 and 2030. Net forest uptake of CO_2 must be preserved or enhanced, likely through both expansion of forests and reduction in carbon loss from forest fires, which are predicted to increase over this time period. This example assumes a 10 percent reduction in direct landfill emissions from the recycling and waste sector; however, aggressive implementation of the suite of measures proposed in this Plan could further reduce emissions from this sector by 2030.

In total, the measures described above would produce reductions to bring California's statewide greenhouse gas emissions to an estimated 284 $MMTCO_2E$ in 2030. While the potential mix of future climate policies articulated in this section is only an example, it serves to demonstrate that the measures in the Scoping Plan can not only move California to its 2020 goal, but also provide an expandable framework for much greater long-term greenhouse gas emissions reductions.

D. Conclusion

California's commitment to address global warming has never been greater. The vast amount of interest, support, and input that ARB has received since this plan began to take shape is evidence of a clear understanding of the need to take action and support for the State's efforts to lead the way. The time has come to shift away from a 'business-as-usual' approach to climate change and to move toward the lasting and sustainable goal of a clean energy future.

Reaching our goals will take a great deal of leadership, commitment, and a willingness to embrace new approaches and seek out new solutions. California's plan to reduce greenhouse gas emissions must also take into account the impacts of this transition and be designed in particular to address the needs of low-income communities, small businesses, and California's working families.

Reaching our goals will also require involvement and support from all levels of government in California, and a coordinated effort with other states, regions, and countries. The solutions and technologies we develop here will be used around the world to help others transition to a clean energy future and contribute to the fight against global warming.

Reaching our goals will also require flexibility. As we move forward, we must be prepared to make mid-course corrections. AB 32 wisely requires ARB to update its Scoping Plan every five years, thereby ensuring that California stays on the path toward a low carbon future.

This plan is part of a new chapter for California that in many ways began with the passage and signing of AB 32. It proposes a comprehensive set of actions designed to reduce greenhouse gas emissions in California, improve our environment, reduce our dependence on oil, diversify our energy sources, save energy, create new jobs, and enhance public health. The challenge California has taken on is large but the opportunities are even greater. It is now time to turn this plan into action.

ACKNOWLEDGMENTS

This Scoping Plan was prepared by the Air Resources Board. This document was made possible by the hard work of numerous contributors. Below is a list of advisory committees and State agencies that directly provided input to this Scoping Plan.

Team Support

Climate Action Team

Climate Action Team Sector Subgroups

- Agriculture
- Cement
- Energy
- Forest
- Green Buildings
- Land Use
- Recycling and Waste Management
- State Fleet
- Water-Energy
- Economics

Advisory Committees

Market Advisory Committee

Environmental Justice Advisory Committee

Economic and Technology Advancement Advisory Committee

State Agencies

Governor's Office of Planning and Research

California Environmental Protection Agency

Business, Transportation and Housing Agency

Resources Agency

State and Consumer Services Agency

Department of Food and Agriculture

California Energy Commission

California Public Utilities Commission

California Transportation Commission

Department of Conservation

Department of Forestry and Fire Protection

Department of General Services

Department of Parks and Recreation

Department of Public Health

Department of Toxic Substances Control

Department of Transportation

Department of Water Resources

Housing and Community Development

Integrated Waste Management Board

Office of Environmental Health Hazard Assessment

State Water Resources Control Board

Department of Pesticide Regulation

& Roberta Fegg

State of California
Air Resources Board

Climate Change Scoping Plan

Resolution 08-47

December 11, 2008

Agenda Item No.: 08-10-2

WHEREAS, the Legislature has enacted the Global Warming Solutions Act of 2006 (AB 32; Health and Safety Code section 38500 et seq.), which declares that global warming poses a serious threat to the environment of California and creates a comprehensive multi-year program to reduce greenhouse gas (GHG) emissions that cause global warming;

WHEREAS, the adverse impacts of climate change include more droughts, more frequent and extreme heat waves, erratic storm and flood events, decreases in winter snowpack, a rise in sea level, increases in water temperatures, an increase in coastal erosion, intrusion of sea water, an increase in the duration of wildfire season, and increased occurrences of unhealthy ozone levels;

WHEREAS, climate change mitigation and adaptation measures can be complementary and are often intricately linked;

WHEREAS, AB 32 designates the Air Resources Board (ARB or the Board) as the State agency charged with monitoring and regulating sources of GHG emissions in California in order to reduce these emissions;

WHEREAS, section 38561(a) of the Health and Safety Code directs the Board, on or before January 1, 2009, to prepare and approve a Scoping Plan for achieving the maximum technologically feasible and cost-effective reductions in GHG emissions by 2020;

WHEREAS, section 38561(a) of the Health and Safety Code also requires ARB to consult with all State agencies having jurisdiction over sources of GHGs on all elements of the Scoping Plan that pertain to energy-related matters, to ensure reduction activities adopted and implemented by ARB are complementary, non-duplicative and can be implemented in an efficient and cost-effective manner;

WHEREAS, section 38561(b) of the Health and Safety Code requires the Scoping Plan to identify and make recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and nonmonetary incentives for sources and categories of sources that the Board finds necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of GHG emissions by 2020;

WHEREAS, section 38561(c) of the Health and Safety Code requires ARB to consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada and the European Union in making the determinations required in Health and Safety Code section 38561(b);

WHEREAS, section 38561(d) of the Health and Safety Code requires ARB to evaluate the total potential costs and total potential economic and noneconomic benefits of the Scoping Plan to California's economy, environment, and public health, using the best available economic models, emissions estimation techniques, and other scientific methods;

WHEREAS, section 38561(e) of Health and Safety Code requires ARB, in developing its plan, to take into account the relative contribution of each source or source category to statewide GHG emissions, and the potential for adverse effects on small businesses, and to recommend a de minimis threshold of GHG emissions below which emission reduction requirements will not apply;

WHEREAS, section 38561(f) of the Health and Safety Code requires ARB, in developing its plan, to identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices;

WHEREAS, section 38561(g) of the Health and Safety Code requires ARB to conduct a series of public workshops to give interested parties an opportunity to comment on the Scoping Plan, and that a portion of these workshops should take place in regions that have the most significant exposure to air pollution, including, but not limited to communities with minority populations, communities with low-income populations, or both;

WHEREAS, section 38652(b) of the Health and Safety Code requires ARB, in adopting greenhouse gas regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, to design the regulations in a manner that is equitable and seeks to minimize costs and maximize the total benefits to California; ensure that activities taken to comply with the regulations do not disproportionately impact low-income communities; ensure that activities undertaken pursuant to the regulations complement efforts to achieve and maintain ambient air quality standards and to reduce toxic air contaminant emissions; consider the cost-effectiveness of the regulations; consider overall societal benefits; minimize administrative burden; and minimize leakage;

WHEREAS, section 38565 of the Health and Safety Code requires ARB to ensure that greenhouse gas emission reduction rules, regulations, programs, mechanisms and incentives under ARB's jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California;

WHEREAS, sections 39600 and 39601 of the Health and Safety Code authorize the ARB to adopt standards, rules and regulations and to do such acts as may be necessary for the proper execution of the powers and duties granted to and imposed upon the ARB by law;

WHEREAS, ARB has adopted and is implementing numerous programs to reduce criteria pollutants, diesel particulate, and air toxics emissions, including the 2007 State Implementation Plan, the Goods Movement Emissions Reduction Plan, and the Diesel Risk Reduction Plan;

WHEREAS, local air pollution control and air quality management districts are currently responsible for implementing many programs that regulate air pollution from stationary and area sources;

WHEREAS, the Board acknowledges the importance of ensuring adequate and reliable energy supplies while the State implements AB 32;

WHEREAS, in preparing the Proposed Scoping Plan, ARB staff considered advice and input from the Environmental Justice Advisory Committee and the Economic and Technology Advancement Advisory Committee;

WHEREAS, in June 2008 ARB staff prepared and circulated for public review a *Draft Climate Change Scoping Plan* (Draft Plan); staff then held three public workshops to discuss the Draft Plan, considered public comments received on the Draft Plan, and modified the Draft Plan in response to these comments;

WHEREAS, in October 2008 ARB staff prepared and circulated for public review a *Proposed Climate Change Scoping Plan*, in accordance with the requirements set forth in Health and Safety Code section 38561;

WHEREAS, the California Environmental Quality Act (CEQA) requires that no project which may have significant adverse environmental impacts may be adopted as originally proposed if feasible alternatives or mitigation measures are available to reduce or eliminate such impacts, unless specific overriding considerations are identified which outweigh the potential adverse consequences of any unmitigated impacts;

WHEREAS, CEQA allows public agencies to prepare a plan or other written documentation in lieu of an environmental impact report (i.e., a functional equivalent environmental document), once the Secretary of the Resources Agency has certified an agency's regulatory program pursuant to section 21080.5 of the Public Resources Code;

WHEREAS, pursuant to section 21080.5 of the Public Resources Code, the Secretary of the Resources Agency has certified that portion of ARB's regulatory program that involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans;

WHEREAS, Board regulations under ARB's certified regulatory program provide that prior to taking final action on any proposal for which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue;

WHEREAS, on October 15, 2008, ARB staff prepared and circulated for public review, in accordance with CEQA and Board regulations, a functional equivalent environmental document which is set forth in Appendix J to the *Proposed Climate Change Scoping Plan*;

WHEREAS in consideration of the *Proposed Climate Change Scoping Plan*, the written and oral testimony presented by the public, industry and government agencies, and the environmental documentation prepared by Board staff, the Board finds that:

1. ARB staff has consulted with all State agencies, including the Public Utilities Commission (PUC) and the State Energy Resources Conservation and Development Commission (CEC), having jurisdiction over sources of greenhouse gases on all elements of the Plan that pertain to energy-related matters, as required by Health and Safety Code section 38561(a);

2. ARB has carefully considered the joint opinion adopted by the PUC and CEC on October 17, 2008, which recommends strategies to help reduce greenhouse gas emissions from the electricity and natural gas sectors;

3. The recommendations in the *Proposed Scoping Plan* are necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020;

4. ARB has considered all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada and the European Union, as provided in Health and Safety Code section 38561(c);

5. ARB staff prepared an analysis to evaluate the total potential costs and total potential economic and noneconomic benefits of the *Proposed Climate Change Scoping Plan* to California's economy, environment, and public health; this analysis was prepared using the best available economic models, emissions estimation techniques, and other scientific methods, as required by Health and Safety Code section 38561(d);

6. In developing the *Proposed Climate Change Scoping Plan*, ARB took into account the relative contribution of each source or source category to

statewide GHG emissions, and the potential for adverse effects on small businesses, as provided in Health and Safety Code section 38561(e);

7. The *Proposed Climate Change Scoping Plan* recommends a de minimis threshold of GHG emissions below which emission reduction requirements will not apply, as provided in Health and Safety Code section 38561(e);

8. The *Proposed Climate Change Scoping Plan* identifies opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, as provided in Health and Safety Code section 38561(f);

9. In accordance with Health and Safety Code section 38561(g), ARB staff organized over 250 public workshops, workgroup events and formal meetings throughout the State, and participated in over 350 meetings and conferences involving external stakeholders, including workshops in regions of the state that have the most significant exposure to air pollutants;

10. The *Proposed Climate Change Scoping Plan* meets all of the requirements of AB 32.

WHEREAS, pursuant to the requirements of the California Environmental Quality Act and the Board's regulations under its certified regulatory program, the Board further finds that:

11. ARB staff prepared a functional equivalent environmental document for the *Proposed Climate Change Scoping Plan* which indicates that there may be potential adverse environmental impacts from the measures included in the Plan; however, these impacts are speculative and cannot be quantified or further described until the details of the measures are developed and set forth in actual proposed regulations;

12. The Board has considered alternatives to the measures identified in the *Proposed Climate Change Scoping Plan* and has identified no feasible alternatives at this time which would reduce or eliminate any potential adverse environmental impacts, while at the same time ensuring that necessary reductions in greenhouse gas emissions will be achieved;

13. At this time there are no feasible mitigation measures that ARB can impose to lessen the potential adverse impacts of the *Proposed Climate Change Scoping Plan* on the environment, and no less stringent alternatives that will accomplish the goals imposed by AB 32 with fewer potential environmental impacts;

14. None of modifications to the *Proposed Climate Change Scoping Plan* alter any of the conclusions reached in the functional equivalent environmental

document, or would require recirculation of the document as provided in CEQA Guidelines section 15088.5;

15. The potential adverse environmental impacts of the measures included in the *Proposed Climate Change Scoping Plan* are outweighed by the substantial reduction in greenhouse gas emissions and public health benefits that will result from their adoption and implementation;

16. The considerations identified above override any adverse environmental impacts that may occur from adoption and implementation of the *Proposed Climate Change Scoping Plan*;

17. As regulations implementing the *Proposed Climate Change Scoping Plan* are developed, detailed environmental impact analyses, including a discussion of regulatory alternatives and mitigation measures, will be performed as part of the rulemaking process;

18. As regulations implementing the *Proposed Climate Change Scoping Plan* are developed, specific economic impact analyses will be performed in conjunction with the rulemaking process and will be considered by the Board in acting on those regulations;

19. In accordance with Public Resources Code 21081(a)(2), for Scoping Plan measures that are within the responsibility and jurisdiction of another public agency, that agency shall be responsible for completing the appropriate environmental review and, with respect to each significant effect identified in the environmental review, shall be responsible for adopting feasible changes or alterations to the measures to mitigate or avoid, as appropriate, the significant environmental effects that have been identified. An initial list of agencies responsible for Plan measures is included in Appendix C of the Plan.

20. ARB regulations which have been adopted and are included in the measures recommended in the *Proposed Climate Change Scoping Plan* were subjected to environmental review by the Board at the time of their adoption and no further analysis is required at this time; and

21. The Executive Officer is the decision maker for the purposes of responding to environmental issues raised on the *Proposed Climate Change Scoping Plan,* and by approving this Resolution 08-47 the Board is not prejudging any of the responses that will be made by the Executive Officer to these environmental issues.

NOW, THEREFORE, BE IT RESOLVED, that subject to the Executive Officer's approval of written responses to environmental issues that have been raised, the Board is initiating steps toward the final approval of the *Proposed Climate Change Scoping*

Plan and its Appendices, as set forth in Attachments A and B hereto, with the modifications identified at the December 11, 2008 public hearing.

BE IT FURTHER RESOLVED that the Executive Officer is the decision maker for the purposes of title 17, California Code of Regulations, section 60007; the Board directs the Executive Officer to prepare and approve written responses to all significant environmental issues that have been raised, and then to either: (1) return the *Proposed Climate Change Scoping Plan* to the Board for further consideration if it is determined that such action is warranted, or (2) take final action to approve the *Proposed Climate Change Scoping Plan* with the modifications identified at the December 11, 2008 public hearing, any conforming modifications that may be appropriate, and any modifications that are necessary to ensure that all feasible measures or feasible alternatives that would substantially reduce any significant adverse environmental impacts have been incorporated into the final action.

BE IT FURTHER RESOLVED that once final action has been taken by the Executive Officer to approve the *Climate Change Scoping Plan*, as agreed to and modified by the Board, the Board directs the Executive Officer to make the modified Plan available to the public.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to perform the environmental analyses required by CEQA in conjunction with future rulemaking actions to implement the *Climate Change Scoping Plan*, and to ensure that the potential environmental impacts identified in the Plan, and any other impacts are subsequently identified, are avoided or mitigated to the extent feasible.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to ensure that the requirements of Health and Safety Code section 38562(b) are met for all proposed regulations to implement the *Climate Change Scoping Plan*, and that the requirements of Health and Safety Code section 38570(b) are met for all proposed regulations to implement market-based compliance mechanisms.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to design greenhouse gas regulations that affect stationary sources so that they utilize, to the extent practicable and appropriate, local air district permitting programs and compliance determination mechanisms.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to provide funding to the local air districts using State funding mechanisms to reimburse districts for involvement in specific, identified activities related to implementation and enforcement of greenhouse gas emission reduction measures.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop a joint workplan with the local air districts to define how to efficiently and effectively implement and administer the Scoping Plan.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop a program to provide GHG emissions verifier training without cost to District staff who meet required education and experience qualifications.

BE IT FURTHER RESOLVED that the Board recognizes that emission sources subject to ARB's mandatory reporting regulation must report directly to the State and directs the Executive Officer to develop a software tool that will allow the export of data to the districts.

BE IT FURTHER RESOLVED that the Board recognizes that consistent implementation and enforcement of greenhouse gas emission reduction programs is crucial to minimize administrative burdens and that the future cap-and-trade program, including reporting and verification of offsets, should be administered at the state level.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to establish a working group of public health agencies and organizations, including, but not limited to, the Department of Public Health, the Office of Environmental Health Hazard Assessment, and local public health agencies, to review and provide input to the staff on proposed greenhouse gas reduction measures.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop a methodology using available information to assess the potential cumulative air pollution impacts of proposed regulations to implement the Scoping Plan.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to identify communities already adversely impacted by air pollution as specified in Health and Safety Code section 38570 (b)(1) before the adoption of a cap-and-trade program.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to design the implementation of AB 32, including the cap-and-trade system, to complement California's criteria and toxic air contaminant programs and be consistent with ARB's environmental justice policies, in furtherance of achieving the statewide greenhouse gas emissions limit.

BE IT FURTHER RESOLVED that the Board recognizes that through the SB 375 (Stats. 2008, Chapter 728) process, local governments and transportation agencies are key partners in ARB's efforts to reduce greenhouse gas emissions, that improved land use and transportation planning is needed to provide Californians with affordable, high quality options for housing and mobility that will result in reduced greenhouse gas emissions, and that the greenhouse gas reductions associated with more sustainable growth will increase over time.

BE IT FURTHER RESOLVED that the Board recognizes that the technical work of the SB 375 Regional Targets Advisory Committee (RTAC) is critical to building a solid foundation for Board consideration of regional targets.

BE IT FURTHER RESOLVED that as input to the SB 375 target setting process, the RTAC should recommend a method to evaluate the full potential for reducing greenhouse gas emissions in each major region of the state, and statewide, using improved land use patterns, indirect source rules, enhanced bike, walk, and transit infrastructure, and pricing policies where applicable (including congestion, toll, and parking pricing). This evaluation should be done for 2020 and 2035, employ the best available data and models, and identify barriers to achieving this full potential.

BE IT FURTHER RESOLVED that it is the Board's intent that the greenhouse gas emission reductions associated with the SB 375 regional targets represent the most ambitious achievable targets. The estimated reductions in the Scoping Plan will be adjusted to reflect the outcome of the Board's decision on SB 375 targets.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to solicit input from experts to advise ARB on its continuing evaluation of the economic effects of implementing AB 32, including identification of additional models or other economic analysis tools that could be used in the ongoing economic analysis. This will include opportunities for interested parties to share their economic modeling results.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to consider the effects of the program on the overall California economy as staff develops the cap-and-trade regulations and to take into account the joint opinion adopted by the PUC and the CEC on October 17, 2008, while recognizing that the joint opinion was developed based on consideration of the electricity and natural gas sectors, and that the recommendations in the opinion may need to be adapted to meet the needs of the California economy as a whole.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to solicit expert input on key questions related to the distribution or auction of allowances and the use of revenue.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer, as part of the cap-and-trade rulemaking, to consider the economic implications of different cap-and-trade program design options, including:

- various scenarios for allowance distribution (percent auction vs. free distribution, method of distribution);
- various scenarios for the use of auction revenue;
- the initial cap level and the rate of decline of the cap over time;
- the potential supply of offsets within and outside California; and

- the economic and co-benefit effects of limits on the use of offsets.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to coordinate the economic analysis of California's AB 32 program with the analysis conducted for the Western Climate Initiative.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with California small businesses during the development of Scoping Plan regulations, to consider the size of the business and type of industry in developing the regulations, and to identify financing programs that could help alleviate costs to small businesses.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the CEC, the PUC and other agencies, as appropriate, to ensure that California's energy demands are met, and that the Scoping Plan and AB 32 are implemented in a manner to avoid disproportionate geographic impacts on energy rates.

BE IT FURTHER RESOLVED that the Board is committed to a cap-and-trade program as an important component of California's comprehensive program to achieve greenhouse gas reductions.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to consider the economic and public health impacts of proposed regulations to implement the Scoping Plan, as well as the requirements of section 38562(b) and 38570(b), as appropriate. For sector-specific regulations affecting sources that are also included in the cap-and-trade program, the staff shall also propose findings to identify the reasons that the emission reductions are best achieved using the proposed regulatory approach.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer, by December 31, 2009, to examine and report on:

- estimates of overall costs and savings and the cost-effectiveness of the reductions, including appropriate inclusion of reductions in co-pollutants;
- estimates of the timing of capital investments, annual expenditures to repay those investments, and the resulting cost savings;
- sensitivity of the results to changes in key inputs, including energy price forecasts and estimates of measure costs and savings; and
- impacts on small businesses.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to update the Board on the public health impacts of climate change as well as the impacts of potential measures that may be taken to mitigate climate change.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to report on the status of the Early Action Measures.

BE IT FURTHER RESOLVED that the Board, in coordination with California Environmental Protection Agency and other state agencies, will take responsibility for the tracking of Scoping Plan implementation and the development of accounting systems to promote consistency and avoid double counting of emission reductions, especially across sectors, to ensure achievement of the AB 32 goals.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to report on the status of Scoping Plan implementation to the Board twice a year.

I hereby certify that the above is a true and correct copy of Resolution 08-47, as adopted by the Air Resources Board.

Monica Vejar

Monica Vejar, Clerk of the Board

California Environmental Protection Agency

Air Resources Board

California Greenhouse Gas Inventory for 2000-2008 — by Category as Defined in the Scoping Plan

million tonnes of CO2 equivalent - (based upon IPCC Second Assessement Report's Global Warming Potentials)

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Transportation	**171.13**	**173.71**	**180.36**	**178.03**	**181.71**	**184.32**	**184.11**	**183.84**	**174.99**
On Road	***159.40***	***161.69***	***168.40***	***166.17***	***169.22***	***170.82***	***170.49***	***170.79***	***163.30***
Passenger Vehicles	126.91	129.25	135.43	132.83	134.24	134.51	133.80	133.34	128.51
Heavy Duty Trucks	32.49	32.45	32.97	33.34	34.98	36.31	36.68	37.45	34.79
Ships & Commercial Boats	***3.77***	***3.56***	***3.87***	***4.04***	***4.06***	***4.36***	***4.45***	***4.38***	***4.32***
Aviation (Intrastate)	***2.68***	***2.50***	***2.66***	***2.59***	***2.64***	***2.70***	***2.68***	***2.96***	***2.42***
Rail	***1.86***	***1.87***	***2.48***	***2.41***	***2.89***	***3.32***	***3.50***	***3.15***	***2.52***
Unspecified	***3.41***	***4.08***	***2.94***	***2.81***	***2.90***	***3.11***	***3.00***	***2.56***	***2.44***
Electric Power	**103.92**	**120.62**	**106.49**	**109.89**	**119.96**	**110.98**	**107.66**	**111.10**	**116.35**
In-State Generation	***59.93***	***63.86***	***50.87***	***49.08***	***57.40***	***51.75***	***56.28***	***55.16***	***55.12***
Natural Gas	51.06	55.55	42.42	41.01	48.66	43.21	47.62	47.20	48.07
Other Fuels	8.87	8.31	8.45	8.07	8.74	8.54	8.67	7.96	7.05
Imported Electricity	***43.99***	***56.76***	***55.62***	***60.81***	***62.56***	***59.22***	***51.38***	***55.94***	***61.24***
Unspecified Imports	13.83	24.69	25.42	30.21	31.32	28.44	26.40	30.57	35.19
Specified Imports	30.16	32.07	30.19	30.60	31.24	30.78	24.98	25.37	26.05
Commercial and Residential	**42.93**	**41.02**	**43.79**	**41.38**	**42.54**	**40.79**	**41.47**	**41.83**	**43.13**
Residential Fuel Use	***30.13***	***28.62***	***29.35***	***28.31***	***29.34***	***28.08***	***28.46***	***28.61***	***28.45***
Natural Gas	28.52	27.34	28.03	26.59	27.30	25.89	26.52	26.65	26.10
Other Fuels	1.61	1.27	1.32	1.72	2.04	2.19	1.93	1.96	2.35
Commercial Fuel Use	***11.69***	***11.32***	***13.37***	***12.81***	***12.71***	***12.56***	***12.84***	***12.73***	***14.31***
Natural Gas	10.24	10.07	12.11	11.34	11.13	10.90	11.58	11.35	12.51
Other Fuels	1.45	1.25	1.26	1.46	1.59	1.66	1.26	1.38	1.80
Commercial Cogeneration Heat Output	***1.11***	***1.07***	***1.08***	***0.26***	***0.49***	***0.15***	***0.17***	***0.49***	***0.37***
Industrial	**97.27**	**94.70**	**96.73**	**96.14**	**90.87**	**90.72**	**90.47**	**93.82**	**92.66**
Refineries	***33.25***	***33.07***	***33.87***	***34.80***	***34.06***	***35.31***	***36.09***	***36.07***	***35.65***
General Fuel Use	***18.76***	***17.87***	***19.53***	***16.39***	***16.28***	***14.80***	***15.17***	***14.78***	***14.82***
Natural Gas	13.82	11.92	12.80	10.26	10.53	9.86	9.90	9.76	9.14
Other Fuels	4.94	5.94	6.73	6.13	5.76	4.93	5.27	5.02	5.69
Oil & Gas Extraction [1]	***18.41***	***18.45***	***17.37***	***19.51***	***19.31***	***18.01***	***16.48***	***16.52***	***17.04***
Fuel Use	17.72	17.62	16.64	18.78	18.94	17.66	15.72	15.75	16.27
Fugitive Emissions	0.69	0.83	0.73	0.74	0.37	0.35	0.77	0.77	0.78
Cement Plants	***9.41***	***9.51***	***9.61***	***9.72***	***9.82***	***9.92***	***9.75***	***9.17***	***8.61***
Clinker Production	5.43	5.52	5.60	5.68	5.77	5.85	5.80	5.55	5.31
Fuel Use	3.97	4.00	4.01	4.03	4.05	4.07	3.95	3.62	3.30
Cogeneration Heat Output	***11.96***	***10.69***	***10.84***	***10.79***	***6.19***	***6.91***	***6.90***	***11.22***	***10.47***
Other Process Emissions	***5.49***	***5.11***	***5.50***	***4.94***	***5.22***	***5.78***	***6.08***	***6.07***	***6.06***
Recycling and Waste	**6.20**	**6.28**	**6.21**	**6.29**	**6.23**	**6.52**	**6.59**	**6.53**	**6.71**
Landfills [2]	***6.20***	***6.28***	***6.21***	***6.29***	***6.23***	***6.52***	***6.59***	***6.53***	***6.71***

California Environmental Protection Agency
Air Resources Board

California Greenhouse Gas Inventory for 2000-2008
— by Category as Defined in the Scoping Plan

million tonnes of CO2 equivalent - (based upon IPCC Second Assessement Report's Global Warming Potentials)

	2000	2001	2002	2003	2004	2005	2006	2007	2008
High GWP	**10.95**	**11.34**	**11.97**	**12.75**	**13.57**	**14.23**	**14.92**	**15.27**	**15.65**
Ozone Depleting Substance (ODS) Substitutes	***8.55***	***9.30***	***10.12***	***10.92***	***11.74***	***12.41***	***13.05***	***13.47***	***13.89***
Electricity Grid SF6 Losses [3]	***1.14***	***1.15***	***1.07***	***1.05***	***1.05***	***1.04***	***1.00***	***0.97***	***0.96***
Semiconductor Manufacturing [2]	***1.26***	***0.89***	***0.78***	***0.78***	***0.78***	***0.78***	***0.87***	***0.84***	***0.80***
Agriculture [4]	**25.44**	**25.37**	**28.42**	**28.49**	**28.82**	**28.99**	**29.90**	**28.26**	**28.06**
Livestock	***13.61***	***14.10***	***14.56***	***14.88***	***14.81***	***15.36***	***15.63***	***15.96***	***16.28***
Enteric Fermentation (Digestive Process)	7.49	7.64	7.86	7.97	7.97	8.26	8.33	8.52	8.70
Manure Management	6.12	6.47	6.70	6.91	6.84	7.10	7.30	7.44	7.58
Crop Growing & Harvesting	***8.01***	***7.46***	***9.48***	***9.41***	***9.51***	***9.03***	***9.08***	***8.53***	***7.95***
Fertilizers	6.55	6.21	8.06	8.02	8.03	7.58	7.44	7.08	6.72
Soil Preparation and Disturbances	1.37	1.18	1.34	1.31	1.41	1.37	1.56	1.36	1.15
Crop Residue Burning	0.09	0.07	0.07	0.08	0.07	0.08	0.08	0.09	0.09
General Fuel Use	***3.82***	***3.81***	***4.39***	***4.20***	***4.50***	***4.60***	***5.19***	***3.78***	***3.82***
Diesel	2.51	2.68	3.02	2.94	3.15	3.38	3.85	2.66	2.93
Natural Gas	1.00	0.75	0.95	0.85	0.82	0.69	0.77	0.79	0.72
Gasoline	0.31	0.38	0.40	0.41	0.52	0.52	0.57	0.32	0.17
Other Fuels	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Forestry	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Wildfire (CH4 & N2O Emissions)	***0.19***	***0.19***	***0.19***	***0.19***	***0.19***	***0.19***	***0.19***	***0.19***	***0.19***
Total Gross Emissions	***458.03***	***473.23***	***474.15***	***473.15***	***483.88***	***476.73***	***475.31***	***480.85***	***477.74***
Forestry Net Emissions	***-4.72***	***-4.53***	***-4.40***	***-4.33***	***-4.32***	***-4.17***	***-4.04***	***-4.07***	***-3.98***
Total Net Emissions	***453.31***	***468.69***	***469.75***	***468.82***	***479.56***	***472.56***	***471.27***	***476.77***	***473.76***

[1] Reflects emissions from combustion of natural gas, diesel, and lease fuel plus fugitive emissions
[2] These categories are listed in the Industrial sector of ARB's GHG Emission Inventory sectors
[3] This category is listed in the Electric Power sector of ARB's GHG Emission Inventory sectors
[4] Reflects use of updated USEPA models for determining emissions from livestock and fertilizers

Sulfur Hexafluoride (SF_6) Emission Reductions from Gas Insulated Switchgear

This page last reviewed August 08, 2011

Overview:

On June 21, 2007, as part of the California Global Warming Solutions Act of 2006 (AB 32) the Air Resources Board (ARB) approved the reduction of sulfur hexafluoride (SF_6) emissions from electricity transmission and distribution equipment as an early action measure. Accordingly, ARB staff, in collaboration with interested stakeholders, developed a control measure to address these emissions. The SF_6 Gas Insulated Switchgear Final Regulation Order was developed and became effective June 17, 2011.

ARB has undertaken other SF_6 emission reduction measures for non-electricity sectors. Information regarding these measures can be found at these related links:

- ARB's SF_6 non-electricity and non-semiconductor applications
- ARB's Semiconductor Applications

What's New

- On August 23, 2011, ARB will hold a stakeholder working group meeting to help discuss issues or concerns with the implementation of the recently adpoted regulation.

Past Events

- On April 11, 2011, the SF6 Gas Insulated Switchgear Rulemaking website was updated with the following documents:
  - Second Notice of Public Availability of Modified Text
  - Proposed Second 15-Day Modifications
- On February 2, 2011, the Office of Administrative Law (OAL) issued the Decision of Disapproval of Part of the Regulatory Action for the (SF6) Emissions from Gas Insulated Switchgear Regulation. OAL approved nine of the ten proposed sections for the SF6 regulation, but disapproved proposed section 95356. The Decision notice as well as the language of the approved portion of the regulation can be found on the SF6 Gas Insulated Switchgear Rulemaking website
- On December 21, 2010, the Final Rulemaking Package was filed with the Office of Administrative Law.
- September 9, 2010, the SF6 Gas Insulated Switchgear Rulemaking website was updated with the following documents:
  - Notice of Public Availability of Modified Text
  - Proposed 15-Day Modifications
- January 7, 2010
  - Proposed Regulatory Language
  - Staff Report: Initial Statement of Reasons (ISOR) and its Appendices
- On January 13, 2009, ARB distributed a survey requesting information from stakeholders on Sulfur Hexafluoride (SF_6) emissions from the electricity sector and particle accelerators. You can download the survey and attachments below:
  - Survey Cover Letter
  - Sulfur Hexafluoride (SF_6) Survey in MS Word format
  - Attachment A
  - Attachment B
  - Confidentiality Overview
  - Confidential Information Submittal Form
- September 2, 2009, Public Workshop
- July 27, 2009, Third Technical Stakeholder Working Group meeting.
- April 30, 2009, Second Technical Stakeholder Working Group meeting.
- January 14, 2009, Technical Stakeholder Working Group meeting

Related Links:

- California Global Warming Solutions Act of 2006 (AB 32)
- ARB's SF_6 Non-Electricity and Non-Semiconductor Applications
- ARB's Semiconductor Applications(includes other High GWP emissions in addition to SF_6)
- ARB's Scoping Plan
- ARB's Proposed Mandatory Greenhouse Gas Reporting Regulations
- EPA Voluntary SF_6 Program
- EPA Report on Mitigation of Non-CO_2 Greenhouse Gases

FINAL REGULATION ORDER

Adopt new Subarticle 3.1, Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear sections 95350 to 95359, title 17, California Code of Regulations, to read as follows:

[Note: All of the text below is new language to be added to the California Code of Regulations (CCR)]

Subchapter 10. Climate Change

Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions

Subarticle 3.1. Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear

§ 95350. Purpose, Scope, and Applicability.

(a) *Purpose*. The purpose of this regulation is to achieve greenhouse gas emission reductions by reducing sulfur hexafluoride (SF_6) emissions from gas insulated switchgear.

(b) *Applicability.* The provisions of this subarticle apply to owners of gas insulated switchgear. Any person who is subject to this subarticle must meet the requirements of this subarticle, notwithstanding any contractual arrangement that person may have with any third parties.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95351. Definitions.

(a) For the purposes of this subarticle, the following definitions apply**:**

(1) **"Active GIS Equipment"** means non-hermetically sealed SF_6 gas insulated switchgear that is:

(A) Connected through busbars or cables to the GIS owner's electrical power system; or

(B) Fully-charged, ready for service, located at the site in which it will be activated, and employs a mechanism to monitor SF_6 emissions.

"Active GIS equipment" does not include equipment in storage.

(2) **“Electrical Power System”** means the combination of electrical generators (i.e., power plants), transmission and distribution lines, equipment, circuits, and transformers used to generate and transport electricity from the generator to consumption areas or to adjacent electrical power systems.

(3) **"Emergency Event"** means a situation arising from a sudden and unforeseen event including, but not limited to, an earthquake, flood, or fire.

(4) **“Emission rate”** means, subject to the provisions of section 95356(e), a GIS owner’s total annual SF_6 emissions from all active GIS equipment divided by the average annual SF_6 nameplate capacity of all active GIS equipment.

(5) **“Executive Officer”** means the Executive Officer of the Air Resources Board (ARB) or his or her designee.

(6) **“Gas container”** means a vessel containing or designed to contain SF_6. ”Gas container” includes pressurized cylinders, gas carts, or other containers.

(7) **“Gas-insulated switchgear or GIS”** means all electrical power equipment insulated with SF_6 gas regardless of location. Gas insulated switchgear or GIS includes switches, stand-alone gas-insulated equipment, and any combination of electrical disconnects, fuses, electrical transmission lines, transformers and/or circuit breakers used to isolate gas insulated electrical equipment.

(8) **“GIS Owner”** means the person who owns gas insulated switchgear. “GIS owner” excludes temporary ownership by the original equipment manufacturer during GIS equipment transport and installation at a customer’s site.

(9) **“Hermetically Sealed Gas Insulated Switchgear”** means switchgear that is designed to be gas-tight and sealed for life. This type of switchgear is pre-charged with SF_6, sealed at the factory, and is not refillable by its user.

(10) **“Nameplate Capacity”** means the design capacity of SF_6 specified by the manufacturer for optimal performance of a GIS device. Nameplate capacity may be found on the nameplate attached to the GIS device, or may be stated within the manufacturer’s official product specifications.

(11) **“NIST-Traceable Standards”** means national, traceable measurement standards developed by the National Institute of Standards and Technology (NIST).

(12) **“Person”** shall have the same meaning as defined in Health and Safety Code section 39047.

(13) **“Responsible Official**” means one of the following:

(A) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person; or

(B) For a partnership or sole proprietorship, a general partner or the proprietor, respectively; or

(C) For a municipal, state, federal, or other public agency, either a principal executive officer or a ranking elected official.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95352. Maximum Annual SF_6 Emission Rate.

For each calendar year specified below, the maximum annual SF_6 emission rate for each GIS owner’s active GIS equipment shall not exceed the following:

Maximum Annual SF_6 Emission Rate	
Calendar Year	**Maximum Allowable SF_6 Emission Rate**
2011	10.0%
2012	9.0%
2013	8.0%
2014	7.0%
2015	6.0%
2016	5.0%
2017	4.0%
2018	3.0%
2019	2.0%
2020, and each calendar year thereafter	1.0%

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95353. Emergency Event Exemption.

(a) A GIS owner may request emissions from an emergency event to be exempted from the calculation of the maximum allowable emission rate if it is demonstrated to the Executive Officer's satisfaction that the release of SF_6:

(1) Could not have been prevented by the exercise of prudence, diligence, and care; and

(2) Was beyond the control of the GIS owner.

(b) A request for an exemption pursuant to this section must be submitted in writing to the Executive Officer within 30 calendar days after the occurrence of the emergency event, and must contain the following information:

(1) The GIS owner's name, physical address, mailing address, e-mail address and telephone number;

(2) A detailed description of the emergency event, including but not limited to the following:

(A) The nature of the event (e.g., fire, flood, earthquake);

(B) The date and time the event occurred;

(C) The location of the event;

(D) The GIS equipment that was affected by the event;

(E) The amount of SF_6 released (in pounds);

(3) A statement and supporting documentation that the release occurred as a result of an emergency event; and

(4) A signed and dated statement, under penalty of perjury, provided by the appropriate responsible official that the statements and information contained in the submitted request are true, accurate, and complete.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95354. SF_6 Inventory Measurement Procedures.

(a) GIS owners must do all of the following:

(1) Establish and adhere to written procedures to track all gas containers as they are leaving and entering storage;

(2) Weigh all gas containers on a scale that is certified by the manufacturer to be accurate to within one percent of the true weight;

(3) Calibrate all scales used to measure quantities that are to be reported under this subarticle by:

(A) Using calibration procedures specified by the scale manufacturer; or

(B) If a scale manufacturer has not specified calibration procedures, using:

1. A NIST traceable standard; and

2. A published calibration method identified as appropriate for that scale by either the International Society of Weighing and Measurement or the National Conference on Weights and Measures.

(4) Calibrate scales used to measure quantities reported under this subarticle prior to the first reporting year.

(5) Recalibrate scales used to measure quantities reported under this subarticle at least annually, or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(b) GIS owners must:

(1) Establish and maintain a log of all measurements required by this section;

(2) Record the scale calibration methods used pursuant to this section; and

(3) Retain all documents and records required by this section for a minimum of three years.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95355. Recordkeeping.

GIS owners must:

(a) Establish and maintain a current and complete GIS equipment inventory, which includes the following information for each piece of equipment:

(1) Manufacturer serial number;

(2) Equipment type (e.g., circuit breaker, transformer, etc);

(3) Seal type (hermetic or non-hermetic);

(4) Equipment manufacturer name;

(5) Date equipment was manufactured;

(6) Equipment voltage capacity (in kilovolts);

(7) Equipment SF_6 nameplate capacity (charge in pounds);

(8) A chronological record of the dates on which SF_6 was transferred into or out of active GIS equipment;

(9) The amount, in pounds, of SF_6 transferred into or out of the active GIS equipment;

(10) Equipment status (active or inactive); and

(11) Equipment location:

(A) The physical address for each piece of equipment must be listed; and

(B) Complete records must be kept of changes to the equipment inventory and the dates the changes occurred (such as installation of new equipment, removal of equipment, and disposition of the equipment (e.g., sold, returned to manufacturer, etc.)).

(b) Establish and maintain a current and complete inventory of gas containers, which includes the following information for each container:

(1) A unique identification number;

(2) Size;

(3) Location;

(4) The weight, in pounds, of SF_6 in each container at the end of each calendar year, and when gas containers are added or removed from inventory.

(c) Retain SF_6 gas and equipment purchase documentation (such as contracts, material invoices, receipts, etc.);

(d) Retain all records required by this subarticle for a minimum of three calendar years;

(1) GIS owners headquartered in California must retain all records at a location within California;

(2) GIS owners headquartered in other states may retain all records at location in California or at their business offices nearest to California;

(e) Have all records available for ARB inspection at time of inspection; and

(f) Upon request by ARB, provide these records to the Executive Officer.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95356. Annual Reporting Requirements.

(a) By June 1, 2012, and June 1st of each year thereafter, each GIS owner must submit an annual report to the Executive Officer for emissions that occurred during the previous calendar year.

(b) The annual report must contain all of the following information:

(1) Reporting entity name, physical address, and mailing address;

(2) Location of records and documents maintained in California if different from the reporting entity's physical address.

(3) Name and contact information including e-mail address and telephone number of the person submitting the report, and the person primarily responsible for preparing the report;

(4) The year for which the information is submitted;

(5) A signed and dated statement provided by the appropriate responsible official that the information has been prepared in accordance with this

subarticle, and that the statements and information contained in the submitted emission data are true, accurate, and complete.

(6) Annual SF_6 emissions as calculated using the equation specified in subsection (d), below;

(7) Annual SF_6 emission rate as calculated using the equation specified in subsection (e), below;

(8) A gas insulated switchgear inventory report containing the information required by Section 95355, subsections (a)(1) through (a)(10); and

(9) A gas container inventory report containing the information required by Section 95355, subsections (b)(1) through (b)(4).

(c) The annual report shall be submitted to the Executive Officer as follows:

(1) GIS owners subject to the requirements of title 17, California Code of Regulations, section 95100 *et seq*., shall use the ARB Greenhouse Gas Reporting Tool or other mechanism, as specified in title 17, California Code of Regulations, section 95104.

(2) GIS owners not subject to the requirements of title 17, California Code of Regulations, section 95100 *et seq*., may either:

(A) Use the ARB's Greenhouse Gas Reporting tool, or other mechanism, as specified in title 17, California Code of Regulations, section 95104; or

(B) Submit reports in writing to ARB through the US Postal Service, electronic mail or by personal delivery.

(d) *Annual SF_6 Emissions*. GIS owners must use the following equation to determine their SF_6 emissions:

Equation for determining annual SF_6 emissions:

User Emissions = (Decrease in SF_6 inventory) + (Acquisitions of SF_6) – (Disbursements of SF_6) − (Net increase in total nameplate capacity of active GIS equipment owned).

Where:

Decrease in SF_6 inventory = (SF_6 stored in containers, but not in equipment, at the beginning of the year) - (SF_6 stored in containers, but not in equipment, at the end of the year).

Acquisitions of SF_6 = (SF_6 purchased in bulk from chemical producers, distributors, or other entities) + (SF_6 purchased from equipment manufacturers, distributors, or other entities with or inside active GIS equipment) + (SF_6 returned to site after off-site recycling).

Disbursements of SF_6 = (SF_6 in bulk and contained in active GIS equipment that is sold to other entities) + (SF_6 returned to suppliers) + (SF_6 sent off site for recycling) + (SF_6 sent to destruction facilities).

Net increase in total nameplate capacity of active GIS equipment owned = (The nameplate capacity of new active GIS equipment) - (Nameplate capacity of retiring active GIS equipment).

(e) *Annual SF_6 Emission Rate.* GIS owners shall use the following equations to determine their SF_6 emission rate.

Equation for determining emissions rate:

$$ER = \frac{Emissions}{C_{avg}}$$

Where:	ER	=	Emission Rate
	Emissions	=	Annual emissions per subsection (d) (lbs)
	C_{avg}	=	Average system nameplate capacity as expressed in the equation below (lbs)

$$C_{avg} = \frac{\sum_{i=1}^{n}\left(d_i C_i\right)}{365}$$

Where:	C_{avg}	=	The average system nameplate capacity (lbs)
	n	=	The number of GIS devices
	d_i	=	The number of days during the year the GIS device was in active service
	C_i	=	The nameplate capacity (lbs) of the GIS device

NOTE: Authority cited: Sections 38510, 38560, 38580, 39600, and 39601, Health and Safety Code. Reference: Sections 38560, 39600, and 39601, Health and Safety Code.

§ 95357. Treatment of Confidential Information.

Information submitted pursuant to this subarticle may be claimed as confidential. Such information shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 through 91022.

NOTE: Authority cited: Sections 38510, 38560, 39600, 39601, and 41511, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95358. Enforcement.

(a) *Penalties.* Penalties may be assessed for any violation of this subarticle pursuant to Health and Safety Code section 38580. Each day during any portion of which a violation occurs is a separate offense.

(b) Each day or portion thereof that any report required by this subarticle remains unsubmitted, is submitted late, or contains incomplete or inaccurate information, shall constitute a single, separate violation of this subarticle.

(c) Any exceedance of the maximum allowable SF_6 emission rate for a calendar year shall constitute a single, separate violation of this subarticle for each day of the calendar year.

(d) *Injunctions.* Any violation of this subarticle may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38560, 39600, 39601, and 41510, Health and Safety Code. Reference: Sections 38580, 39600, 39601, 41510, and 41513, Health and Safety Code.

§ 95359. Severability.

Each part of this subarticle is deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of this subarticle shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

Sulfur Hexafluoride (SF_6) Emission Reductions from Gas Insulated Switchgear

This page last reviewed August 08, 2011

Overview:

On June 21, 2007, as part of the California Global Warming Solutions Act of 2006 (AB 32) the Air Resources Board (ARB) approved the reduction of sulfur hexafluoride (SF_6) emissions from electricity transmission and distribution equipment as an early action measure. Accordingly, ARB staff, in collaboration with interested stakeholders, developed a control measure to address these emissions. The SF_6 Gas Insulated Switchgear Final Regulation Order was developed and became effective June 17, 2011.

ARB has undertaken other SF_6 emission reduction measures for non-electricity sectors. Information regarding these measures can be found at these related links:

- ARB's SF_6 non-electricity and non-semiconductor applications
- ARB's Semiconductor Applications

What's New

- On August 23, 2011, ARB will hold a stakeholder working group meeting to help discuss issues or concerns with the implementation of the recently adpoted regulation.

Past Events

- On April 11, 2011, the SF6 Gas Insulated Switchgear Rulemaking website was updated with the following documents:
  - Second Notice of Public Availability of Modified Text
  - Proposed Second 15-Day Modifications
- On February 2, 2011, the Office of Administrative Law (OAL) issued the Decision of Disapproval of Part of the Regulatory Action for the (SF6) Emissions from Gas Insulated Switchgear Regulation. OAL approved nine of the ten proposed sections for the SF6 regulation, but disapproved proposed section 95356. The Decision notice as well as the language of the approved portion of the regulation can be found on the SF6 Gas Insulated Switchgear Rulemaking website
- On December 21, 2010, the Final Rulemaking Package was filed with the Office of Administrative Law.
- September 9, 2010, the SF6 Gas Insulated Switchgear Rulemaking website was updated with the following documents:
  - Notice of Public Availability of Modified Text
  - Proposed 15-Day Modifications
- January 7, 2010
  - Proposed Regulatory Language
  - Staff Report: Initial Statement of Reasons (ISOR) and its Appendices
- On January 13, 2009, ARB distributed a survey requesting information from stakeholders on Sulfur Hexafluoride (SF_6) emissions from the electricity sector and particle accelerators. You can download the survey and attachments below:
  - Survey Cover Letter
  - Sulfur Hexafluoride (SF_6) Survey in MS Word format
  - Attachment A
  - Attachment B
  - Confidentiality Overview
  - Confidential Information Submittal Form
- September 2, 2009, Public Workshop
- July 27, 2009, Third Technical Stakeholder Working Group meeting.
- April 30, 2009, Second Technical Stakeholder Working Group meeting.
- January 14, 2009, Technical Stakeholder Working Group meeting

Related Links:

- California Global Warming Solutions Act of 2006 (AB 32)
- ARB's SF_6 Non-Electricity and Non-Semiconductor Applications
- ARB's Semiconductor Applications(includes other High GWP emissions in addition to SF_6)
- ARB's Scoping Plan
- ARB's Proposed Mandatory Greenhouse Gas Reporting Regulations
- EPA Voluntary SF_6 Program
- EPA Report on Mitigation of Non-CO_2 Greenhouse Gases

FINAL REGULATION ORDER

Adopt new Subarticle 3.1, Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear sections 95350 to 95359, title 17, California Code of Regulations, to read as follows:

[Note: All of the text below is new language to be added to the California Code of Regulations (CCR)]

Subchapter 10. Climate Change

Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions

Subarticle 3.1. Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear

§ 95350. Purpose, Scope, and Applicability.

(a) *Purpose*. The purpose of this regulation is to achieve greenhouse gas emission reductions by reducing sulfur hexafluoride (SF_6) emissions from gas insulated switchgear.

(b) *Applicability.* The provisions of this subarticle apply to owners of gas insulated switchgear. Any person who is subject to this subarticle must meet the requirements of this subarticle, notwithstanding any contractual arrangement that person may have with any third parties.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95351. Definitions.

(a) For the purposes of this subarticle, the following definitions apply**:**

(1) **"Active GIS Equipment"** means non-hermetically sealed SF_6 gas insulated switchgear that is:

(A) Connected through busbars or cables to the GIS owner's electrical power system; or

(B) Fully-charged, ready for service, located at the site in which it will be activated, and employs a mechanism to monitor SF_6 emissions.

"Active GIS equipment" does not include equipment in storage.

(2) **“Electrical Power System”** means the combination of electrical generators (i.e., power plants), transmission and distribution lines, equipment, circuits, and transformers used to generate and transport electricity from the generator to consumption areas or to adjacent electrical power systems.

(3) **"Emergency Event"** means a situation arising from a sudden and unforeseen event including, but not limited to, an earthquake, flood, or fire.

(4) **“Emission rate”** means, subject to the provisions of section 95356(e), a GIS owner’s total annual SF_6 emissions from all active GIS equipment divided by the average annual SF_6 nameplate capacity of all active GIS equipment.

(5) **“Executive Officer”** means the Executive Officer of the Air Resources Board (ARB) or his or her designee.

(6) **“Gas container”** means a vessel containing or designed to contain SF_6. ”Gas container” includes pressurized cylinders, gas carts, or other containers.

(7) **“Gas-insulated switchgear or GIS”** means all electrical power equipment insulated with SF_6 gas regardless of location. Gas insulated switchgear or GIS includes switches, stand-alone gas-insulated equipment, and any combination of electrical disconnects, fuses, electrical transmission lines, transformers and/or circuit breakers used to isolate gas insulated electrical equipment.

(8) **“GIS Owner”** means the person who owns gas insulated switchgear. “GIS owner” excludes temporary ownership by the original equipment manufacturer during GIS equipment transport and installation at a customer’s site.

(9) **“Hermetically Sealed Gas Insulated Switchgear”** means switchgear that is designed to be gas-tight and sealed for life. This type of switchgear is pre-charged with SF_6, sealed at the factory, and is not refillable by its user.

(10) **“Nameplate Capacity”** means the design capacity of SF_6 specified by the manufacturer for optimal performance of a GIS device. Nameplate capacity may be found on the nameplate attached to the GIS device, or may be stated within the manufacturer’s official product specifications.

(11) **“NIST-Traceable Standards”** means national, traceable measurement standards developed by the National Institute of Standards and Technology (NIST).

(12) **"Person"** shall have the same meaning as defined in Health and Safety Code section 39047.

(13) **"Responsible Official"** means one of the following:

(A) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person; or

(B) For a partnership or sole proprietorship, a general partner or the proprietor, respectively; or

(C) For a municipal, state, federal, or other public agency, either a principal executive officer or a ranking elected official.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95352. Maximum Annual SF_6 Emission Rate.

For each calendar year specified below, the maximum annual SF_6 emission rate for each GIS owner's active GIS equipment shall not exceed the following:

Maximum Annual SF_6 Emission Rate	
Calendar Year	**Maximum Allowable SF_6 Emission Rate**
2011	10.0%
2012	9.0%
2013	8.0%
2014	7.0%
2015	6.0%
2016	5.0%
2017	4.0%
2018	3.0%
2019	2.0%
2020, and each calendar year thereafter	1.0%

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95353. Emergency Event Exemption.

(a) A GIS owner may request emissions from an emergency event to be exempted from the calculation of the maximum allowable emission rate if it is demonstrated to the Executive Officer's satisfaction that the release of SF_6:

(1) Could not have been prevented by the exercise of prudence, diligence, and care; and

(2) Was beyond the control of the GIS owner.

(b) A request for an exemption pursuant to this section must be submitted in writing to the Executive Officer within 30 calendar days after the occurrence of the emergency event, and must contain the following information:

(1) The GIS owner's name, physical address, mailing address, e-mail address and telephone number;

(2) A detailed description of the emergency event, including but not limited to the following:

(A) The nature of the event (e.g., fire, flood, earthquake);

(B) The date and time the event occurred;

(C) The location of the event;

(D) The GIS equipment that was affected by the event;

(E) The amount of SF_6 released (in pounds);

(3) A statement and supporting documentation that the release occurred as a result of an emergency event; and

(4) A signed and dated statement, under penalty of perjury, provided by the appropriate responsible official that the statements and information contained in the submitted request are true, accurate, and complete.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95354. SF_6 Inventory Measurement Procedures.

(a) GIS owners must do all of the following:

(1) Establish and adhere to written procedures to track all gas containers as they are leaving and entering storage;

(2) Weigh all gas containers on a scale that is certified by the manufacturer to be accurate to within one percent of the true weight;

(3) Calibrate all scales used to measure quantities that are to be reported under this subarticle by:

(A) Using calibration procedures specified by the scale manufacturer; or

(B) If a scale manufacturer has not specified calibration procedures, using:

1. A NIST traceable standard; and

2. A published calibration method identified as appropriate for that scale by either the International Society of Weighing and Measurement or the National Conference on Weights and Measures.

(4) Calibrate scales used to measure quantities reported under this subarticle prior to the first reporting year.

(5) Recalibrate scales used to measure quantities reported under this subarticle at least annually, or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(b) GIS owners must:

(1) Establish and maintain a log of all measurements required by this section;

(2) Record the scale calibration methods used pursuant to this section; and

(3) Retain all documents and records required by this section for a minimum of three years.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95355. Recordkeeping.

GIS owners must:

(a) Establish and maintain a current and complete GIS equipment inventory, which includes the following information for each piece of equipment:

(1) Manufacturer serial number;

(2) Equipment type (e.g., circuit breaker, transformer, etc);

(3) Seal type (hermetic or non-hermetic);

(4) Equipment manufacturer name;

(5) Date equipment was manufactured;

(6) Equipment voltage capacity (in kilovolts);

(7) Equipment SF_6 nameplate capacity (charge in pounds);

(8) A chronological record of the dates on which SF_6 was transferred into or out of active GIS equipment;

(9) The amount, in pounds, of SF_6 transferred into or out of the active GIS equipment;

(10) Equipment status (active or inactive); and

(11) Equipment location:

(A) The physical address for each piece of equipment must be listed; and

(B) Complete records must be kept of changes to the equipment inventory and the dates the changes occurred (such as installation of new equipment, removal of equipment, and disposition of the equipment (e.g., sold, returned to manufacturer, etc.)).

(b) Establish and maintain a current and complete inventory of gas containers, which includes the following information for each container:

(1) A unique identification number;

(2) Size;

(3) Location;

(4) The weight, in pounds, of SF_6 in each container at the end of each calendar year, and when gas containers are added or removed from inventory.

(c) Retain SF_6 gas and equipment purchase documentation (such as contracts, material invoices, receipts, etc.);

(d) Retain all records required by this subarticle for a minimum of three calendar years;

(1) GIS owners headquartered in California must retain all records at a location within California;

(2) GIS owners headquartered in other states may retain all records at location in California or at their business offices nearest to California;

(e) Have all records available for ARB inspection at time of inspection; and

(f) Upon request by ARB, provide these records to the Executive Officer.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95356. Annual Reporting Requirements.

(a) By June 1, 2012, and June 1st of each year thereafter, each GIS owner must submit an annual report to the Executive Officer for emissions that occurred during the previous calendar year.

(b) The annual report must contain all of the following information:

(1) Reporting entity name, physical address, and mailing address;

(2) Location of records and documents maintained in California if different from the reporting entity's physical address.

(3) Name and contact information including e-mail address and telephone number of the person submitting the report, and the person primarily responsible for preparing the report;

(4) The year for which the information is submitted;

(5) A signed and dated statement provided by the appropriate responsible official that the information has been prepared in accordance with this

subarticle, and that the statements and information contained in the submitted emission data are true, accurate, and complete.

(6) Annual SF_6 emissions as calculated using the equation specified in subsection (d), below;

(7) Annual SF_6 emission rate as calculated using the equation specified in subsection (e), below;

(8) A gas insulated switchgear inventory report containing the information required by Section 95355, subsections (a)(1) through (a)(10); and

(9) A gas container inventory report containing the information required by Section 95355, subsections (b)(1) through (b)(4).

(c) The annual report shall be submitted to the Executive Officer as follows:

(1) GIS owners subject to the requirements of title 17, California Code of Regulations, section 95100 *et seq*., shall use the ARB Greenhouse Gas Reporting Tool or other mechanism, as specified in title 17, California Code of Regulations, section 95104.

(2) GIS owners not subject to the requirements of title 17, California Code of Regulations, section 95100 *et seq*., may either:

(A) Use the ARB's Greenhouse Gas Reporting tool, or other mechanism, as specified in title 17, California Code of Regulations, section 95104; or

(B) Submit reports in writing to ARB through the US Postal Service, electronic mail or by personal delivery.

(d) *Annual SF_6 Emissions*. GIS owners must use the following equation to determine their SF_6 emissions:

Equation for determining annual SF_6 emissions:

User Emissions = (Decrease in SF_6 inventory) + (Acquisitions of SF_6) – (Disbursements of SF_6) − (Net increase in total nameplate capacity of active GIS equipment owned).

Where:

Decrease in SF_6 inventory = (SF_6 stored in containers, but not in equipment, at the beginning of the year) - (SF_6 stored in containers, but not in equipment, at the end of the year).

Acquisitions of SF_6 = (SF_6 purchased in bulk from chemical producers, distributors, or other entities) + (SF_6 purchased from equipment manufacturers, distributors, or other entities with or inside active GIS equipment) + (SF_6 returned to site after off-site recycling).

Disbursements of SF_6 = (SF_6 in bulk and contained in active GIS equipment that is sold to other entities) + (SF_6 returned to suppliers) + (SF_6 sent off site for recycling) + (SF_6 sent to destruction facilities).

Net increase in total nameplate capacity of active GIS equipment owned = (The nameplate capacity of new active GIS equipment) - (Nameplate capacity of retiring active GIS equipment).

(e) *Annual SF_6 Emission Rate.* GIS owners shall use the following equations to determine their SF_6 emission rate.

Equation for determining emissions rate:

$$ER = \frac{Emissions}{C_{avg}}$$

Where:	ER	=	Emission Rate
	Emissions	=	Annual emissions per subsection (d) (lbs)
	C_{avg}	=	Average system nameplate capacity as expressed in the equation below (lbs)

$$C_{avg} = \frac{\sum_{i=1}^{n}\left(d_i C_i\right)}{365}$$

Where:	C_{avg}	=	The average system nameplate capacity (lbs)
	n	=	The number of GIS devices
	d_i	=	The number of days during the year the GIS device was in active service
	C_i	=	The nameplate capacity (lbs) of the GIS device

NOTE: Authority cited: Sections 38510, 38560, 38580, 39600, and 39601, Health and Safety Code. Reference: Sections 38560, 39600, and 39601, Health and Safety Code.

§ 95357. Treatment of Confidential Information.

Information submitted pursuant to this subarticle may be claimed as confidential. Such information shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 through 91022.

NOTE: Authority cited: Sections 38510, 38560, 39600, 39601, and 41511, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

§ 95358. Enforcement.

(a) *Penalties.* Penalties may be assessed for any violation of this subarticle pursuant to Health and Safety Code section 38580. Each day during any portion of which a violation occurs is a separate offense.

(b) Each day or portion thereof that any report required by this subarticle remains unsubmitted, is submitted late, or contains incomplete or inaccurate information, shall constitute a single, separate violation of this subarticle.

(c) Any exceedance of the maximum allowable SF_6 emission rate for a calendar year shall constitute a single, separate violation of this subarticle for each day of the calendar year.

(d) *Injunctions.* Any violation of this subarticle may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38560, 39600, 39601, and 41510, Health and Safety Code. Reference: Sections 38580, 39600, 39601, 41510, and 41513, Health and Safety Code.

§ 95359. Severability.

Each part of this subarticle is deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of this subarticle shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38560, 39600, and 39601, Health and Safety Code. Reference: Sections 38562, 38580, 39600, and 39601, Health and Safety Code.

California Climate Action Registry General Reporting Protocol

Reporting Entity-Wide Greenhouse Gas Emissions

Version 3.1 | January 2009

Acknowledgements

The California Climate Action Registry would like to thank and acknowledge the many experts who have helped make both the General Reporting Protocol and the California Registry a reality. While it is impossible to properly acknowledge everyone who contributed to this document, the following organizations have provided valuable guidance and insightful feedback throughout this project:

Arthur D. Little / ICF Consulting

California Climate Action Registry Technical Advisory Committee

California Council for Environmental and Economic Balance

California Energy Commission

California Energy Commission Registry Workgroup

California EPA

CH2M Hill

First Environment, Inc.

Lawrence Berkeley National Laboratory

Natural Resources Defense Council Convened State Registry Collaborative

Pacific Gas & Electric Corporation

Pew Center on Global Climate Change

Sacramento Municipal Utility District

Science Applications International Corporation (SAIC)

U.S. Department of Energy

U.S. Energy Information Administration (1605(b) Program)

U.S. Environmental Protection Agency

U.S. EPA Climate Leaders

World Business Council for Sustainable Development

World Resources Institute

The California Registry is also grateful to all of the individuals who participated in the California Registry's public workshops and meetings. Most notably, Jill Gravender, Pierre duVair, Jeff Wilson, Robyn Camp, Mike McCormick, Sam Hitz, and Rachel Tornek should be singled out for their extensive contributions in the drafting and finalization of this report and its subsequent versions.

The California Registry would like to extend a special acknowledgement to the World Business Council for Sustainable Development and the World Resources Institute for the excellent work and leadership embodied in their "Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard." Their work has provided the foundation for the California Registry's General Reporting Protocol.

In addition, the California Energy Commission has played an instrumental role in developing and recommending technical and policy guidance to the California Registry's staff and board of directors for the General Reporting Protocol.

The California Registry wishes to extend a special thank you to SAIC for their help preparing the General Reporting Protocol.

The California Registry also wishes to thank its members and verifiers whose application of earlier versions of the protocol has informed the clarifications provided in this version.

Finally, the California Registry wishes to thank the California Energy Commission and the Energy Foundation for their generous financial support.

Table of Contents



Appendices

List of Tables and Figures

List of Equations

Abbreviations and Acronyms

AFV	Alternative Fuel Vehicle
Btu	British thermal unit(s)
CARB	California Air Resources Board
CARROT	Climate Action Registry Reporting Online Tool
CBECS	Commercial Building Energy Consumption Survey
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CFC	chlorofluorocarbon
CHP	combined heat and power
CH_4	methane
COI	conflict of interest
COP	coefficient of performance
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
eGRID	Emissions & Generation Resource Integrated Database
EIA	U.S. Energy Information Administration
EIIP	Emissions Inventory Improvement Program
EPA	U.S. Environmental Protection Agency
g	gram(s)
GCV	gross caloric value
GHG	greenhouse gas
GRP	General Reporting Protocol
GWP	global warming potential
ha	hectare(s)
HCFC	hydrochlorofluorocarbon
HDV	heavy duty vehicle
HFC	hydrofluorocarbon
HHV	higher heating value
HSE	health, safety, and environmental
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
ISO	International Organization for Standardization
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound
LDT	light duty truck
LHV	lower heating value
LPG	liquefied petroleum gas
Mcf	thousand cubic feet
mi	mile(s)
MMBtu	one million British thermal units
MWh	megawatt-hour(s)
NCV	net caloric value
NO_x	oxides of nitrogen
N_2O	nitrous oxide
ODS	ozone depleting substance
PFC	perfluorocarbon
RFA	Request for Applications
SAR	IPCC Second Assessment Report (1996)
SF_6	sulfur hexafluoride
TAR	IPCC Third Assessment Report (2001)
T&D	transmission and distribution
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Part I Introduction

The General Reporting Protocol (the GRP) provides guidance for businesses, government agencies, and non-profit organizations to participate in the California Climate Action Registry (the California Registry), a voluntary greenhouse gas (GHG) registry.

The GRP provides the principles, approach, methodology, and procedures required for participation in the California Registry. It is designed to support the complete, transparent, and accurate reporting of an organization's GHG emissions inventory in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, electricity use, and GHG emissions in a quantifiable manner. The GRP guides participants through the reporting rules, emission calculation methodologies, and the California Registry's standardized reporting mechanism via its web-based reporting system, the Climate Action Registry Reporting Online Tool (CARROT). Reporting guidance for individual industries in the form of sector-specific protocols have been developed over time, and supplement this document. The current version of the GRP and its appendices are available for download on the California Registry's website, www.climateregistry.org.

In addition to the GRP, the California Registry currently offers four sector-specific protocols:

- Cement Protocols,
- Forest Protocols,
- Local Government Operations Protocol, and
- Power/Utility Protocols.

Additional protocols have been developed over time. The sector-specific protocols are considered appendices to the GRP. Forest companies, power generators and electric utilities, cement companies, and local governments should refer to the GRP as well as their respective sector-specific protocol for a complete set of emission accounting and reporting instructions.

By joining the California Registry, participants agree to report their annual GHG emissions according to the guidelines in this Protocol and its appendices. The GRP is intended to be used in combination with the California Registry's General Verification Protocol (GVP) and web-based calculation and reporting tools.

I.1 How to Use the General Reporting Protocol

Who Should Use the GRP

- Businesses, government agencies, and non-profit organizations who want to learn about greenhouse gas emissions tracking for California or nationwide
- California Registry members who are reporting their general emissions or emissions related to a specific sector (forests or utilities)
- Verifiers of general or sector-specific emissions reports
- Technical advisors to companies who report emissions through the California Registry
- The interested general public

How the Protocol is Organized

This Protocol is based on the "Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard" developed by the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI) through "a multi-stakeholder effort to develop a standardized approach to the voluntary reporting of GHG emissions."[1] The calculations and emission factors were selected based on technical advice provided to the California Registry by the State of California.

This Protocol will continue to be refined over time, to add clarity and specificity, to provide guidance for specific industries, and to incorporate new understanding in GHG accounting. Comments on the GRP or other protocols may be submitted to the California Registry using the Protocol Comment Form posted on the California Registry's website.

The Protocol is divided into four parts, composed of a total of fourteen chapters. Each chapter provides guidance on the specific steps participants will need to take to complete and submit their GHG emissions report to the California Registry. Depending upon the complexity and the nature of reported GHG emissions, some of the steps in this Protocol may not apply to all organizations. Nevertheless, the California Registry encourages participants to review the document as a whole to ensure that they have identified all reporting requirements.

---

1 "The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard," World Business Council for Sustainable Development and World Resources Institute, Switzerland, March 2004 (GHG Protocol, 2004).

Part I Introduction

Contains:

- An overview of the GRP and the reporting process
- An introduction to online reporting
- A brief background on the creation and objectives of the California Registry
- Answers to key questions about using the GRP

Part II Determining What You Should Report (Chapters 1-4)

Provides guidance on:

- Determining geographic boundaries (i.e., California, the entire U.S., or worldwide)
- Determining organizational boundaries
- Determining operational boundaries
- Setting an emission baseline

Part III Quantifying Your Emissions (Chapters 5-12)

Provides guidance on calculating:

- Indirect emissions from electricity
- Direct emissions from mobile combustion
- Direct emissions from stationary combustion
- Indirect emissions from co-generation, imported steam, and district heating or cooling
- Direct process emissions
- Direct fugitive emissions
- Optional emissions

Part IV Completing and Submitting Your Report (Chapters 13-14)

Describes how to finalize emissions reports by:

- Determining de minimis emissions
- Preparing and submitting an annual GHG emissions report using CARROT
- Providing an overview of the verification process

Related California Registry Documents

General Verification Protocol: for approved verifiers, California Registry members, and the public interested in verification.

Forest Protocols: for landowners with at least 100 acres of forestland in California. The Forest Protocols consist of three documents: 1) an entity-level protocol, 2) a project protocol, and 3) a verification protocol. Like the GRP and the General Verification Protocol, the forest sector entity-level and verification protocols provide GHG emissions accounting, reporting, and verification guidance at the entity-level. The forest project protocol provides guidance to forest companies that wish to account and report GHG emission reductions resulting from one of three planned activities taking place on the forest company's land: conservation, reforestation or conservation-based forest management.

Power/Utility Protocols: for companies that generate and sell electricity for the wholesale or retail market and/or provide electricity transmission and distribution services. The Power/Utility Protocols consist of two documents: 1) an entity-level protocol and 2) a verification protocol.

Cement Protocols: for companies that manufacture cement. The Cement Protocols consist of two documents: 1) the entity-level protocol and 2) a verification protocol.

Local Government Operations Protocol: for local governments to quantify and report GHG emissions inventories of their municipal operations. The Local Government Operations Protocol consists of one document: 1) the entity-level protocol.

I.2 Background on the California Climate Action Registry

The California Registry is a private non-profit organization that serves as a voluntary greenhouse gas registry to protect, encourage, and promote early actions to reduce GHG emissions. The California Registry provides leadership on climate change by promulgating credible and consistent GHG reporting standards and tools for organizations to measure, report, verify, and reduce their GHG emissions in California and/or the U.S. Following considerable initiative and input from various stakeholders from the business, government, and environmental communities, the California State Legislature established the California Registry in 2000, with technical modifications in 2001.[2]

The purposes of the California Registry are as follows:

1. To enable participating entities to voluntarily measure and record GHG emissions produced after 1990 in an accurate manner and consistent format that is independently verified;
2. To establish standards that facilitate the accurate, consistent, and transparent measurement and monitoring of GHG emissions;
3. To help various entities establish emissions baselines against which any future federal GHG emissions reduction requirements may be applied;

2 California Senate Bill 1771 was signed into law on September 30, 2000, and Senate Bill 527 on October 13, 2001.

4. To encourage voluntary actions to increase energy efficiency and reduce GHG emissions;
5. To ensure that participating organizations receive appropriate consideration for verified emissions results under any future state, federal or international regulatory regime relating to GHG emissions;
6. To recognize, publicize, and promote participants in the California Registry; and
7. To recruit broad participation in the process.

The California Registry was created by the State of California to be a non-profit organization operating outside of the state government, but working closely with the State to develop its reporting and verification procedures such that the State is confident in the quality of the data. To this end, the State has worked closely with the California Registry since its inception to develop its reporting and verification guidance, including both this General Reporting Protocol, the companion Verification Protocol, and also industry-specific reporting protocols.

Joining the California Registry provides several benefits, such as:

1. **Addressing inefficiency –** understanding that emissions are an indication of waste and inefficiency has led many companies to redesign business operations and processes, spur innovation, improve products and services, and help to build competitive advantage.
2. **Managing risk –** taking steps to protect early actions ahead of possible future GHG regulations is a wise risk-management strategy.
3. **Preparing for trading –** developing credible and transparent measurement, verification and reporting methods in order to participate in any future emission trading system.
4. **Showing environmental leadership –** acting early to address climate change to better influence future policy, and to understand the most cost-effective means of managing and reducing emissions.
5. **Demonstrating action on GHG emissions –** reporting verified information to the California Registry helps to address shareholder concerns about adequate corporate actions to reduce GHG emissions.
6. **Preparing for regulation –** verifying an annual GHG inventory helps to prepare for mandatory GHG reporting.

I.3 GHG Accounting and Reporting Principles

The following principles, which serve as the basis of reporting and verifying emissions with the California Registry, are consistent with the WRI/WBCSD GHG Protocol Initiative.[3]

Relevance. Relevant GHG inventories submitted to the California Registry appropriately reflect the GHG emissions of the entity and include emissions information produced in accordance with the program rules on defining reporting boundaries and sources.

Completeness. Complete GHG inventories include emissions from all GHG sources and activities within the specified scope of the participant's report. Baseline and annual emissions results include all sources; vertical and horizontal integration should be properly accounted for.

Consistency. Consistently developed GHG inventories enable meaningful comparison of emissions performance over time and across similar organizations. Additionally, changes to a participant's emission baselines are verified to ensure appropriate comparisons.

Accuracy. Accurate GHG inventories must be within the materiality threshold of 5% of the verifier's estimate of total emissions. The verification process validates the accounting and reporting decisions made by the participant and ensures that the GHG emissions reports are precise and credible.

Transparency. Reporters must make available to their verifiers the necessary information and documentation used to produce the inventory. Additionally, the verification process should be clearly and thoroughly documented to allow the possibility for outside reviews by the State or the California Registry.

I.4 Reporting Requirements and Disclosure

Required Reporting

California Registry participants must submit their GHG emissions to the California Registry each year. Any entity that conducts business activities in the State of California—such as a corporation or other legally constituted body, a non-profit organization, any city, county, or State government agency—may join the California Registry. If an organization does not have emissions in California, then it may report its total U.S. emissions and indicate that California emissions are zero. At a minimum, participants must report their entity-wide emissions for each of the following categories:

- Direct emissions from mobile source combustion
- Direct emissions from stationary combustion

3 GHG Protocol, 2004.


- Indirect emissions from electricity use, imported steam and district heating and cooling
- Direct process emissions
- Direct fugitive emissions

For the first three years after joining the California Registry participants must report at a minimum their CO_2 emissions in California or in the U.S., depending on the geographic scope of their inventory. Starting with the fourth year, participants must report all Kyoto GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6). Participants must submit annual GHG emissions reports (emissions reports) via CARROT. Each annual GHG emissions report must contain at least the following information:

- The geographic scope of the emissions report (whether California-only or nationwide);
- The operational and organizational boundaries of the reporting entity for which GHG emission data is reported;
- A GHG emissions baseline to assess changes in total emissions from year to year, if a participant chooses to define a baseline;
- Total significant direct GHG emissions (including mobile and stationary combustion, process, and fugitive);
- Total significant indirect GHG emissions (from electricity usage, and from co-generation, steam imports, district heating and cooling); and
- Total direct and indirect emissions classified as de minimis.

Before emissions reports will be accepted by the California Registry, this information must be verified by an approved verifier. Participants are eligible to report and receive verification through the California Registry for both California-only and national GHG emission inventories. Verifiers are screened and approved by the California Registry to ensure that they have the necessary skills to appropriately evaluate emissions reports.

The purpose of the verification process is to ensure that the emissions report meets the following criteria:

- Relevance: Report GHG emissions in accordance with the program rules on defining reporting boundaries and sources, using the methodologies and emission factors outlined in the General Reporting Protocol.
- Completeness: Report all significant emissions, defined as at least 95% of the total (both direct and indirect emissions), entity-wide sources (either California-only or nationwide) and disclose any de minimis emissions.
- Consistency: Report total emissions each year of participation in the California Registry.
- Transparency: Report emissions to the California Registry using the California Registry's standardized reporting tool, the Climate Action Registry Reporting Online Tool (CARROT).
- Accuracy: Less than a 5% difference between your calculated total emissions and what an approved verifier calculates your emissions to be.

For every year that a participant has a current annual emissions report, they are considered a *Climate Action Leader*.

Optional Reporting

Each annual GHG emissions report may also contain optional information provided by the participant to highlight their organization's environmental goals, policies, programs and performance, and to report other GHG emissions information. This information is not required to be reported and thus is not verified, but is valuable in providing transparency and enhancing public knowledge. All emissions reports will clearly distinguish between information that is and is not verified. Once accepted by the California Registry, optional information is made available to the public as part of the emissions report.

Participants disclose to the public only information contained in the emissions reports generated through CARROT that include entity-wide emissions from direct and indirect sources, as well as any optional data they consider relevant. Although the California Registry will make available aggregated entity-level emissions data to the public, it will keep all other data (i.e., from the facility- or source-level) confidential, such as activity data, methodologies, and emissions factors. Only the participant, the participant's verifier, and the California Registry can access confidential information, unless the participant allows others to access such information.

I.5 Reporting Uncertainty vs. Inherent Uncertainty

Reporting uncertainty entails the mistakes made in identifying emissions sources, managing data or information, and calculating GHG emissions. Inherent uncertainty refers to scientific uncertainty associated with measuring GHG emissions. The California Registry is aware that there is inherent uncertainty in emissions factors and measurement of activity data through metering and instrumentation – even after the calibration of meters and other data collection methods are verified as accurate.

The GHG emissions accounting and reporting guidelines in the GRP and the independent verification process developed by the California Registry are designed to reduce reporting uncertainty such that it is less than the minimum quality standard. Determining scientific

accuracy is not the focus of the California Registry or its General Reporting Protocol.

I.6 Web-Based Reporting

CARROT (Climate Action Registry Reporting Online Tool)

Submitting an annual GHG emissions report to the California Registry is designed to be as simple and straightforward as possible. Based on this Protocol, the California Registry has developed a web-based reporting application called CARROT (Climate Action Registry Reporting Online Tool), which enables participants to submit emissions reports online.

CARROT serves two purposes: (1) it is the tool through which participants report their emissions, and (2) for many categories of data, it can assist with emissions calculations. It is accessed through the California Registry's website. All emissions information must be reported through CARROT. The website also provides a variety of technical resources for getting started, context-based Help links, and other supporting information including an electronic version of the GRP.

A short demonstration of CARROT and the *CARROT Getting Started Guide Version 3* can also be found on the California Registry's website.

I.7 Technical Assistance

The California Registry has a number of ways to help you as you proceed through the emissions reporting process. You can contact California Registry staff if you have questions or problems at:

- help@climateregistry.org
- 213-891-1444 ext.2 and ask for the Programs Team

Also, CARROT has online help that may answer many of your questions.

Should you need additional assistance, you can also hire a firm to provide technical assistance. A list of State- and California Registry-approved technical assistance providers is on the California Registry's website as a reference.

I.8 CARROT Training and Reporting Orientation

The California Registry holds regular Reporting Orientation sessions to help participants understand how to use the General Reporting Protocol and CARROT application. These workshops include specific guidance on calculating and verifying GHG emissions. All interested parties are invited to participate.

Please contact the California Registry (213-891-1444) for more details and see the website for a calendar of upcoming events (www.climateregistry.org).

I.9 Key Questions

Below are clarifications on some basic issues that should assist you as you begin to prepare your annual GHG emissions report. If you have a question that is not answered in this Protocol, please contact the California Registry.

Membership: **How do I join the California Registry?**

As of October 31, 2008, the California Registry directs all organizations interested in reporting entity-level emissions to our sister organization, The Climate Registry (www.theclimateregistry.org).

The California Registry accepts emissions inventory information from current members through October 31, 2010. In the meantime and going forward, interested parties may become Affiliates of the Climate Action Institute (Institute). Building on the California Registry's community of leaders in business, government, and civil society, the Institute provides education and a forum for discussion on emerging climate policy issues in the West. The Institute continues many of the historic California Registry member services such as climate policy conference call briefings, trainings, an annual conference, Climate Action Champion awards, publications, an annual delegation to the UN Climate Change Conference, and much more.

For information on becoming an Affiliate of the Climate Action Institute, please contact help@climateregistry.org or 213-891-1444, extension 2.

Member Benefits: **What are some of the advantages of joining the California Registry?**

Being a member of the California Registry provides several important benefits to participants, such as addressing inefficiency, managing risk, preparing for emissions trading, showing environmental leadership, demonstrating action on GHG emissions, and preparing for possible CO_2 regulation.

Emissions Trading: **Can I use my California Registry GHG emissions report to trade GHG emissions?**

The General Reporting Protocol provides guidance for calculating an organization's entity-wide GHG emissions inventory, not for creating tradable GHG credits. The

California Registry itself does not serve as a brokerage house for GHG emissions trading, but the reporting and verification processes adopted by California Registry participants will promote credibility, transparency, and accuracy of the data reported. It is possible that information reported to the California Registry can be used by the participant to facilitate participation in private or government-sponsored trading programs in the future, although it is likely that any emissions to be traded will be documented and verified from emissions reduction projects. The California Registry is in the process of developing a wider range of emissions reduction project-based reporting and verification protocols.

Eligibility to Report: **Who may report their GHG emissions?**

Any organization can participate in the California Registry if it can report either its total California emissions, or its total U.S. emissions. If an organization does not have emissions in California, then it may report its total U.S. emissions, and indicate that its California emissions are zero. Organizations with operations in multiple states may not register a single state's emissions (except California emissions). Partial nation-wide reporting is not permitted.

Adhering to the Protocol Guidelines: **Must a company or organization follow this Protocol to participate in the California Registry?**

Participants in the California Registry are expected to make every effort to report in a manner consistent with this Protocol. However, the California Registry recognizes that participants may face unique situations not addressed in the Protocol or in some cases the implementation of the Protocol would create undue burden. While the California Registry seeks to maintain consistency in reporting, participants may use calculation methodologies and emission factors that are verified as more accurate than the default calculations. The California Registry also welcomes suggested revisions to the Protocol.

All comments about the Protocol should be submitted to the California Registry using the Protocol Comment Form, available on the website (www.climateregistry.org). Suggestions should clearly document an alternative approach and the manner in which the alternative approach would continue to improve the Protocol. Suggested revisions will be reviewed by California Registry staff and advisors, then summarized and presented to the California Registry Board for review annually. Changes to the Protocol will be approved by the Board and publicly announced.

Level of Reporting: **Are participants permitted to report only individual facilities?**

At a minimum, you are required to report emissions from all sources in the state of California. If you have multiple facilities, you must report emissions from all facilities. The California Registry encourages members to report at a sub-entity- or facility-level as part of your entity-wide GHG emissions report in CARROT.

A sub-entity may be a business unit, a department or other grouping that you define. If reporting at the sub-entity level, you must report all of your organization's facilities or operations, such that all sub-entity emissions equal your entity's total California or U.S. emissions.

Required Emissions Reporting: **Which GHGs do participants report?**

The California Registry accepts GHG emissions reports that include emissions of the following six GHGs (Kyoto gases):

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur Hexafluoride (SF_6)

Although participants are encouraged to report all of these gases starting in year one, participants may opt to limit their reports to only carbon dioxide (CO_2) emissions during the first three years of participation in the California Registry. After the third year of California Registry participation, participants will be required to include emissions from all six of the Kyoto GHGs (if applicable) in the annual emissions report.

For example, if you joined the California Registry in January 2006, you would report at least your CO_2 emissions emitted during the calendar years 2006-2008. Beginning in calendar year 2009, you must report all six Kyoto gases for this and every subsequent year.

You should report all required direct and indirect emissions. Direct emissions are those emitted from sources owned or controlled by the reporting entity. For example, a cement manufacturer would report direct emissions resulting from the process of manufacturing cement. Indirect emissions are those that result from a participant's actions but are produced from sources owned or controlled by another entity. For example, a participant whose emissions result only from the consumption of electricity would calculate its indirect emissions from the amount of electricity it consumes.

What are de minimis emissions? Do I have to calculate and report absolutely everything?

To be verified, your emissions report must identify all of the sources in your inventory, no matter how small. However, to help reduce reporting burdens and concentrate efforts on your significant emissions, the California Registry permits you to designate a small portion of your emissions as de minimis. De minimis emissions comprise less than 5% of your organization's total GHG emissions, as produced from any combination of sources and gases.

For some participants, identifying and quantifying all of their GHG emissions according to the methodologies in the GRP would be unduly burdensome and not cost-effective. A participant may operate hundreds, if not thousands, of small facilities where the known emissions—including, for example, indirect emissions from electricity consumption or direct emissions from motor vehicle operation—are a small fraction of larger emissions sources from industrial activities. If you can provide estimates that these emissions total less than 5% of your total annual GHG emissions, you do not have to calculate them according to the methodologies in the GRP. De minimis emissions still need to be included in your emissions report.

For example, a participant estimates that it emits 1,000 metric tons of CO_2 each year. Most of these emissions come from an on-site heating and cooling system in its buildings. In addition, this participant also has one company car that is driven approximately 20,000 miles each year. This participant estimates that between 800 and 1000 gallons of gasoline are consumed by this car each year. Using the upper estimate of 1000 gallons, the participant calculates the emissions from this source as 8.8 tons of CO_2/year, and finds that this amount falls below the de minimis threshold of 5% or 50 metric tons CO_2/year. The participant can report this emission source as de minimis in CARROT and provide this estimation to the verifier, along with vehicle records showing the actual miles traveled of the car. In subsequent years, if the operation patterns do not change significantly, the participant can continue to declare and report the emissions from this source as de minimis, and will only need to re-estimate this information every three years.

Historic Data: Can I report emissions data for years prior to the year I joined the California Registry?

Some participants may wish to report GHG emissions data for years prior to the year in which they joined the California Registry. When you join the California Registry, you must specify for which calendar year of emissions you will first report to the California Registry and report your emissions according to the version of the General Reporting Protocol in force at the time of joining. Emissions reported for years prior to the actual year a participant joins the California Registry are considered "historical data" and the participant should use the GRP in force at the time of joining for reporting these data. For each year of historical data, you must report at least your emissions of CO_2. You may also report entity-wide emissions of individual gases for which you have verifiable data, and for which you can report it from that point forward. All historical data must be verified before it can be accepted into the California Registry.

For every year that you report to the California Registry, you must report the emissions associated with all of your operations within your geographic boundary (either California or U.S.). When you choose to report historical data, you must also report all of the emissions associated with all of the facilities you owned or operated in each calendar year. By providing this information, you provide an accounting of your organization's emissions over time. When you re-adjust your emissions baseline to reflect structural changes, you demonstrate your emissions performance over time. The California Registry supports consistent and transparent reporting and verification of annual GHG emissions. In this regard, emissions reports for years prior to joining the California Registry need to comply with the same requirements as for current annual GHG emissions inventories.

Reporting and Reporting Deadlines: How do I report? When do I report?

All participants must report at least their California-wide emissions of carbon dioxide (years 1-3) and all Kyoto gases (years 4+) in five reporting categories to the California Registry using CARROT, the online reporting tool. You can also choose to input your source- and facility-level emissions information using CARROT. CARROT can also help you calculate your emissions in many common emission categories.

You should work to report your emissions in CARROT by no later than June 30 of the year after they were produced, and complete verification by October 31 of the same year. For instance, you should report your 2008 emissions by June 30, 2009 and complete verification by October 31, 2009.

There cannot be any gap years in the data you report. For example, if you joined the California Registry in January 2006, you would report at least your CO_2 emissions for 2006 by June 30, 2007. You would follow the same timetable for reporting your 2007 and 2008 emissions. Beginning with your 2009 emissions, you must report all 6 GHGs by June 30, 2010.

Table I.1 illustrates the minimum reporting requirements over time for a new participant.

Table I.1 Reporting Years

Year	Participant Action
2006	Participant joins the California Registry and tracks 2006 emissions
2007	Participant tracks 2007/reports 2006 CO_2 emissions
2008	Participant tracks 2008/reports 2007 CO_2 emissions
2009	Participant tracks 2009 emissions for all six GHGs/reports 2008 CO_2 emissions
2010	Participant tracks 2010 /reports 2009 emissions for all six GHGs

Confidentiality: **Will the information I report be kept confidential?**

As described above, the public can only view aggregated entity-level emissions data reported to the California Registry. Confidential information will only be accessible to you, the California Registry, and your chosen verifier, unless you allow others to access such information or wish to have it available to the public.

Verification: **Must my report be verified?**

Yes. However, the California Registry understands that in the initial years of participation, some reports may not be verifiable due to the need to change data collection practices or other factors that make it impossible to meet the reporting requirements. Thus, while you must calculate and verify your emissions for each year you wish to report, you are not required to submit your Verification Opinion to the California Registry for the first two years of your participation. This flexibility is intended to allow you to have time to fully understand the calculating, reporting, and verification processes before your emissions information is made available to the public. Participants are eligible to receive verification for California-only or U.S emissions reports. At this time, international emissions reports do not qualify for verification through the California Registry, although you can store international data in CARROT.

Minimum Quality Standard: **What are the requirements for verifying my emissions report?**

Any emissions report submitted to the California Registry must be free of material discrepancies in order to be verified. It is possible that during the verification process, differences will arise between the emissions estimated by the California Registry participant and those estimated by the verifier. These differences between participant and verifier estimations may be classified as either material or immaterial discrepancies. A discrepancy is considered to be material if the overall reported emissions differ from the overall emissions estimated by the verifier by 5% or more. Otherwise the difference is considered to be immaterial.

California Registry-Approved Verifiers: **Who must verify a GHG emissions report?**

In order to have your emissions report accepted into the California Registry database, it must be verified by an independent third-party organization that has been approved by the California Registry. A list of approved verifiers is provided to all California Registry participants and is available on the California Registry's website. The verification process is outlined in Chapter 14.

Before your preferred verifier is approved, the California Registry will review any pre-existing relationship between you and the verifier you select to determine if there is potential for conflict of interest. Also, a State of California representative may accompany a verifier on site visits, as part of their oversight of the verification process. If, in the course of these activities the state representative needs to view confidential information, the state representative will sign a confidentiality agreement with both you and your verifier to protect any information you designate as sensitive.

California Registry-Approved Technical Assistance Providers: **What role do they play?**

Some participants may desire expert assistance to collect, document, and report their emissions to the California Registry and/or otherwise manage and reduce their GHG emissions. The State and the California Registry approve firms qualified to serve as technical assistance providers (TAs). Approved companies have been screened as firms experienced in providing GHG emissions services, and many of them have attended California Registry-sponsored training sessions. Participants are not required to use approved TAs. Neither the California Registry nor the State is responsible for any consulting services or recommendations they may provide.

All firms approved as verifiers also are automatically qualified to act as TAs. A firm cannot provide both technical assistance and verification services to the same client at the same time. A list of technical assistance providers is available on the California Registry's website (www.climateregistry.org).

Role of California State Agencies: What is the relationship between the California Registry and State agencies?

The California Registry was established by California statute as a non-profit voluntary registry for greenhouse gas emissions inventories in order to help organizations to establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied. The State of California was directed to offer its best efforts to ensure that participants receive appropriate consideration for early actions in the event of any future state, federal or international GHG regulatory scheme.

The California Registry and state agencies work together and keep each other informed about current activities. The State of California continues to provide technical guidance to the California Registry and plays a direct oversight role in the verification process. The California Registry gives great weight to state agency guidance, and relies in large part on these recommendations when developing California Registry policies, procedures and tools, including reporting and verification protocols and the online reporting tool. However, final policy and technical decisions are made independently by the California Registry's staff and Board of Directors.

Part II Determining What You Should Report

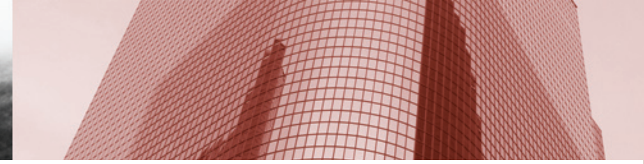
As you begin to prepare your annual GHG emissions report to the California Registry, you first need to consider the geographic and organizational boundaries of your organization. That is, you need to determine which sources of emissions to include in your report based on their location, your organizational structure, and operations. For many participants, particularly firms that are wholly-owned entities operating entirely within the State of California, establishing reporting boundaries will be straightforward. For participants whose operations consist of jointly-owned entities and those with operations outside of California, the process may be more involved.

Part II is designed to help your organization assess what emissions and activities you should include in your report. Chapter 1 begins at the broadest possible level—your report's geographic boundaries. It discusses options for reporting your organization's emissions within the borders of the United States or for those only within the State of California—the minimum requirement for reporting to the California Registry.

After addressing geographic boundaries, Chapter 2 focuses more narrowly on organizational boundaries. The basic unit of participation in the California Registry is an entity in its entirety, as it relates to the geographic boundaries specified in Chapter 1. While only entity-level reporting is required, the California Registry strongly encourages organizations to report at the facility- or sub-entity-level; this greater level of detail builds a more credible database of information and facilitates verification. Organizations that wholly own and fully control all of their GHG emission sources will simply report all of their emissions to the California Registry. For facilities that are owned or controlled by more than one organization, determining organizational boundaries may be more complicated.

Once you have determined your geographic and organizational boundaries, Chapter 3 will help you consider the operational boundaries of your emissions, based on whether they are directly or indirectly caused by your organization.

Chapter 4 provides guidance on selecting a baseline year and on adjusting your baseline over time to capture any changes in the size and scope of your organization. After you have categorized your emissions and defined operational boundaries, you will be ready to move onto estimation methods in Chapters 5-11.

Chapter 1 Geographic Boundaries

> Who should read Chapter 1:
>
> Chapter 1 applies to all participants.
>
> What you will find in Chapter 1:
>
> This chapter explains the options and requirements for determining the geographic scope of your GHG emissions report.
>
> Information you will need:
>
> You will need basic information about the location of your organization's facilities in the state of California and, if you are reporting all national emissions, throughout the U.S.
>
> Cross-References:
>
> It may also be useful to refer to Chapter 2 on organizational boundaries as you examine your geographic boundaries.

II.1.1 Reporting National and California-Based Emissions

The first step in determining what to report to the California Registry is to decide on the geographic scope of your report. You have the option of reporting California-only emissions, or all of your U.S. GHG emissions, which will include California emissions, if any.

Reporting U.S. and California-Only Emissions

The California Registry supports the most comprehensive reporting possible and encourages you to report emissions associated with all of your organization's activities in the United States. If you choose to report your U.S. emissions, you will also need to specifically report your California-based emissions. The California Registry's web-based reporting software is designed to capture your organization's U.S. and California emissions separately so reporting both is easy. Alternately, participants can begin the program by reporting California emissions only and later move to U.S. reporting. If you are reporting at the national level but do not presently have any emissions in California, you must report zero California emissions.

At this time the California Registry will store but does not accept verification information on emissions released by sources outside of the United States.

Reporting California-Only Emissions

If you do not have operations, or do not wish to report your emissions outside California, please report your emissions for California-only. To estimate your California-only emissions you must identify those sources within your organization located in California. Emissions associated with the electricity purchased and consumed in buildings and manufacturing processes occurring in California should be included in the calculation of California-only emissions, regardless of the likely location of the power generation.

Regarding mobile sources, you should report the total GHG emissions for mobile sources registered in California regardless of whether the vehicles travel inside or outside of the state, or whether vehicle fuel was purchased inside or outside of California. Such vehicles may include those your organization owns or leases (see Chapter 3). Vehicles registered by the California Department of Motor Vehicles are considered to be based in California.

Organizations without California Emissions

If you do not have emissions in California, but wish to report to the California Registry, you must report your California emissions as zero. You are able to report to the California Registry and have this information verified, although you may also be assessed an additional registration fee to help cover the State's costs in overseeing verification of the non-California data.

Determining Whether to Report California-Only or U.S. Emissions

There are several reasons why you may wish to complete a U.S. report of your organization's emissions, such as:

- An existing environmental management system already captures emissions at the national-level;
- It will help you prepare for a future federal regulatory regime;
- Corporate decision-making must look at the "big picture" when making efforts to improve efficiency and make least-cost reductions in GHG emissions;
- It enhances your credibility to investors and customers; and
- Environmental stewardship goals are nationwide (and often worldwide).

You may also report only California-based emissions. Examples of the rationale for taking this approach include the following:

- A participant has only California emissions;
- Completing a report for California offers a good learning experience for implementing a more comprehensive national or international corporate accounting scheme in the future;
- Conducting nation-wide accounting is simply too complex and burdensome at this time; and
- The participant owns and controls 100% of all operations in California, while having only partial ownership in operations outside of California, making California-only reporting more straightforward and less burdensome.

II.1.2 Reporting Worldwide Emissions

The California Registry does accept standardized GHG emissions data from operations outside the U.S., and participants can gather and store data in CARROT. However, the California Registry does not have Board-approved reporting and verification protocols for international data; thus, international GHG emissions data are not verified at this time.

II.1.3 Example: Determining Geographic Boundaries

The following example describes how geographic boundaries impact a company's GHG inventory.

An Express Mail Delivery Company with a Fleet Based Inside and Outside of California

An express mail delivery company operates a fleet of 1,000 vehicles, both inside California and outside the state; 350 of the vehicles are registered in California and 650 are registered outside of California.

If the express mail delivery company is reporting California-only emissions, they would report emissions for only the 350 vehicles registered in California.

If the company is reporting its U.S. emissions, they would report the emissions associated with the 350 California-registered vehicles, and separately report the emissions associated with the 650 non-California-based vehicles.

Chapter 2 Organizational Boundaries

> **Who should read Chapter 2:**
> Chapter 2 applies to all participants.
>
> **What you will find in Chapter 2:**
> This chapter considers the options and requirements for determining the organizational scope of your GHG emissions report.
>
> **Information you will need:**
> You will need information that will help you determine which sources of emissions are to be included in your organizational structure and operations, including information about joint ventures, subsidiaries, and similar entities.
>
> **Cross-References:**
> It may also be useful to refer to Chapter 1 on geographic boundaries and Chapter 3 on operational boundaries as you examine your organizational boundaries.

II.2.1 Defining Your Entity

Once you have determined the geographic boundaries of your report, you should identify the significant emissions for each calendar year within those boundaries that are attributable to facilities and operations that you own or control. For the purposes of this Protocol, the basic unit of participation in the California Registry is an entity in its entirety, such as a corporation or other legally constituted body, a city or county, a state government agency, a non-profit organization, etc. At a minimum, you must report your entity-wide (total) emissions. However, the California Registry strongly encourages you to report GHG emissions information at the facility- or source-level as part of your entity-level report. Although facility-level reporting may require more data-entry work into CARROT for participants, it will provide a more detailed and comprehensive picture of your emissions profile and could reduce verification costs.

II.2.2 Reporting Options and Organizational Boundaries

To establish your organizational boundary, you should evaluate all operations, facilities, and sources that fall within your chosen geographic boundary. For those operations and facilities that are wholly-owned, you should report all of the associated emissions. For those operations or facilities in which you have a partial ownership share or working interest, hold an operating license, lease, or otherwise represent joint ventures or partnerships of some kind (both incorporated and unincorporated), you have two options for determining the GHG emissions you should report:

Option 1 – Management Control: Report 100% of the emissions from operations, facilities, and sources that your organization controls.

If you choose to use the management control approach, the California Registry requires participants to determine control based on financial or operational criterion, which must be consistently applied to all operations, facilities, and sources to determine whether or not the associated emissions fall within your organizational boundary.[1]

Option 2 – Equity Share: Report a percentage of the emissions based on your share of financial ownership of an entity, operation, facility or source. Some participants may have contracts or legal agreements that assign ownership of specific GHG emissions or emissions reductions.

Contracts or agreements may serve to clarify your selected organizational boundary. Where you have agreements regarding emission rights or responsibilities, you may wish to disclose this information to the public in the optional section of your emissions report. However, you are required to report your entity-wide emissions using either the management control and/or equity share emissions consolidation approach, regardless of contractual agreements that assign emission rights or responsibilities.

Companies can choose to establish an organizational boundary based upon management control (either financial or operational) or equity share only, but may also report based upon both emissions consolidation approaches. The method chosen must be applied consistently across all operations, facilities, and sources. Once you have selected an approach to define your organizational boundary, the California Registry requires that you use it consistently for each year of reporting.[2]

The consistent use of a single emissions consolidation approach facilitates comparisons of annual emissions

1 Defining management control in either financial or operational terms is consistent with The GHG Protocol; a discussion of the management control criterion and the operational control criterion can be found in section II.2.3.

2 You may in subsequent years choose to report based upon an additional consolidation methodology, but must continue to report according to the initial methodology you select.

reports, helps identify trends in emissions, and supports the establishment of baseline emissions. The consistent use of an approach to set your organizational boundary will also reduce the cost of future verifications.

II.2.3 Reporting Based on Management Control

Management control can be defined in either operational or financial terms. When using management control to determine how to report GHG emissions associated with joint ventures and partnerships you should first select between either the financial or operational criterion, and consistently apply the definitions below in determining how to report these emissions. One or more conditions from those listed below can be used to establish your choice of control approach. If you determine you have control over a particular joint venture or partnership, you should report 100% of the significant emissions of that entity (all of its operations, facilities, and sources). If you determine you do not have control, you should not report any of the emissions associated with the entity.

In most cases, financial control and operational control of an operation, facility or source reside with the same entity. The organization that has financial control typically also has operational control. Consequently, whether or not a joint venture or partnership is deemed to be controlled by your company, and as a result its emissions fall within your organizational reporting boundary, generally will not depend on which of the approaches of control you select.

However, in some sectors such as the oil and gas industry, complex joint ventures and ownership/operator structures can exist where financial and operational control are not vested with the same organization. In these cases the choice to apply a financial or operational definition of control can have a significant impact on what sources must be included in an inventory. In making this decision, participants should take into account their individual situation, and select a criterion that best reflects your actual level of control and the standard practice within your industry. Additionally, industry-specific guidance developed by the California Registry, included as appendices to this reporting protocol, may provide additional guidance on choosing a criterion for determining management control. Table II.2.1 provides an illustration of the reporting responsibility under the management control reporting option.

Financial control is the ability to dictate or direct the financial policies of an operation or facility with the ability to gain the economic rewards from activities of the operation or the facility.

One or more of the following conditions establishes financial control:

- Wholly owning an operation, facility or source.
- Considering an operation to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in your organization's financial statements.
- Governing the financial policies of a joint venture under a statute, agreement or contract.

Table II.2.1 Reporting Based on Management Control

Level of Control of facility/source	Percent of GHGs to Report Under Financial Criterion	Percent of GHGs to Report Under Operational Criterion
Wholly owned	100%	100%
Partially owned with financial and operational control	100%	100%
Partially owned with financial control; no operational control	100%	0%
Partially owned with operational control; no financial control	0%	100%
Not owned but have a capital or financial lease	100%	100%
Not owned but have an operating lease	0%	100%

- Retaining the rights to the majority of the economic benefits and/or financial risks from an operation or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed. These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include your organization casting the majority of votes at a meeting of the board of directors or having the right to appoint/remove a majority of the members of the board in the case of an incorporated joint venture.

Operational control is the authority to develop and carry out the operating policies or health, safety and environmental (HSE) policies of an operation or a facility.[3]

One or more of the following conditions establishes operational control:

- Wholly owning an operation, facility or source.
- Having the full authority to introduce and implement operational and health, safety and environmental policies. In many instances, the authority to introduce and implement operational and HSE policies is explicitly conveyed in the contractual or legal structure of the partnership or joint venture. While in most cases, holding an operator's license is an indication of your organization's authority to implement operational and HSE policies, this may not always be so. If your organization holds an operating license and you believe you do not have operational control, you will need to explicitly demonstrate that your authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

It should be noted that your organization need not be able to control all aspects of operations within a joint venture to have operational control. For instance, making decisions on major capital investments without the approval of other parties in a venture may be beyond the authority of the entity with operational control.

In the case of joint control, two entities each have 50% equity ownership and no stipulations exist to demonstrate that either organization has control of the financial or operating policies of the venture. If you have joint control over a facility and are using financial control as your control criterion, you should report a pro rata share of your emissions based on your economic interest in and/or benefit derived from the operation or activities at a facility. In this case, you would report 50% of the controlled entity's emissions. If you are using operational control as your control criterion, it may be that neither partner has operational control; a separate entity conducting the operation may implement its own operating policies. In such a case, neither partner would report.

Rationale for Choosing Management Control

An important reason for choosing to report emissions based on management control is that when you control how an operation or a facility is managed you are able to control factors such as capital investment and technology choice, how energy is used, and the level of emissions generated. Thus, reporting emissions using the management control approach reflects your ability to implement actions that could reduce GHG emissions. This approach also helps you to monitor the performance of an operation, a facility, and the entity. Most criteria pollutant emission reduction programs, regulations, and trading systems are based on management control rather than equity ownership. When you have management control of an operation or a facility, you typically have greater access to the information and records needed to calculate and report emissions information, helping to minimize the administrative costs of maintaining a GHG emissions inventory.

> Note: Management control is the default method used by CARROT to calculate emissions.

II.2.4 Reporting Based on Equity Share

If you have facilities and operations in which your share of ownership ranges from 1% to 99%, you may choose to report on an equity share basis—either in addition to, or instead of, reporting based on management control. When reporting on an equity share basis, you should include the portion of the emissions from the facility or operations equal to your equity share of the total emissions. If more than one owner of a facility is a participant in the California Registry and one owner chooses to report based on equity share, then each participating owner must agree in advance to also report on an equity share basis. The collective accounting methodologies of multiple owners should ensure that all applicable emissions are reported and no double counting occurs in the reports. Participants will need to provide an attestation of their ownership share, prepared by either a verified legal or financial advisor. This document should identify all owners of the facilities, including their respective shares of ownership. Table II.2.2 provides an illustration of the reporting responsibility under the equity share reporting option.

3 GHG Protocol, 2004.

Table II.2.2 Reporting Based on Equity Share

Level of Ownership	Percent of GHG Emissions to Report
Wholly-owned	100%
Not wholly-owned, but controlled	By equity share
Partially-owned, no control	By equity share

Rationale for Choosing Equity Share

Setting organizational boundaries based on equity share reflects a commercial reality that entities profiting from a business activity typically have an interest in the operation of the activity. Consequently, ownership of GHG emissions could reasonably be based on the level of economic interest in the organization that generated the GHG emissions. In some instances, management control is not always the best measure of “control” or “influence” over a shared facility. Furthermore, with respect to risk, ultimate financial liability is distributed based on equity share. Thus, this approach could allow for a more complete coverage of liability and risk.

II.2.5 Choosing Both Management Control and Equity Share Reporting

Optimally, you should report your GHG emissions using both the management control and equity share approaches. Given the uncertainty of the exact nature of future GHG emissions trading or regulatory regimes, reporting using both methods will provide the greatest flexibility and maximum use of your emissions data in the future.

Also, your choice of a geographic boundary for your report may be affected by the number and diversity of operations and facilities for which you have partial ownership and the method you select for accounting for those emissions. Thus, if you have partial ownership of multiple facilities, you should consider your approach to emissions reporting in light of both your geographic and organizational boundary alternatives. Where you share ownership of operations or facilities, all owners will need to clarify who will report emissions.

II.2.6 Parent Companies, Subsidiaries, and Holding Companies

If your organization is a subsidiary of a corporation or other legally constituted body, you may join the California Registry if your parent organization is not already a member. The parent organization need not participate in the California Registry merely because one or more of its subsidiaries chooses to participate, but members that are subsidiaries must disclose their parent organization to the California Registry.

However, if the parent organization later joins the California Registry, the parent would report emissions from all of its subsidiaries and subsidiaries would not be able to retain separate membership. Holding companies (corporations that are made up of several other corporations) would report following the management control approaches described above. If the holding company controls several subsidiaries, it would report the total emissions from each of its subsidiaries.

II.2.7 Partnerships and Joint Ownership

Situations may exist in which no party in your organization has sufficient management to claim responsibility for reporting. For example, in a Limited Liability Partnership (LLP), it is possible that no single entity would have a controlling or majority equity share. In such a case, the collective partners would come to a mutual agreement to divide the responsibilities for reporting GHG emissions to the California Registry and report accordingly.

For some sectors such as the petroleum industry, it is common to have joint ownership with a single operator. Holding the operating license may not be a sufficient condition for being able to influence the operating policies of an entity or facility. Therefore, you should review all the conditions for management control listed above to determine what emissions you should report.

II.2.8 Leased Facilities/Vehicles and Landlord/Tenant Arrangements

Reporters shall account for and report emissions from leased facilities and vehicles according to the type of lease associated with the facility or source and the organizational boundary approach selected. This guidance applies to California Registry participants that rent office space (i.e., tenants), vehicles, and other facilities or sources (e.g., industrial equipment).

There are two types of leases[4]:

- **Finance or capital lease:** If you have an asset under a finance or capital lease, the California Registry considers this asset to be wholly-owned by you.
- **Operating lease:** If you have an asset under an operating lease, such as a building or vehicle, the California Registry considers this asset to be under your operational control but you do not have any financial risk or reward from owning the asset.

The California Registry considers any lease that is not a finance or capital lease to be an operating lease. In most cases, operating leases cover rented office space and leased vehicles, whereas finance or capital leases are for large industrial equipment.

Short-term rental agreements (e.g., daily car rentals) do not constitute financial or operational control, and therefore emissions from short-term rentals should not be included in your inventory. Emissions from short-term rental equipment may be reported optionally.

Reporting Emissions from Leased Assets

You shall account for and report emissions from a facility/source under a finance or capital lease as though it were an asset wholly-owned and controlled by your company or organization, regardless of the organizational boundary approach selected.

With respect to facilities/sources under an operating lease (e.g., most office space rentals and vehicle leases), the organizational boundary approach selected will determine whether reporting the asset's associated emissions is required or optional. If the organizational boundary approach is either the equity share approach or the financial control criterion under the management control approach, then reporting the emissions from a facility/source with an operating lease is optional. On the other hand, if you choose the operational control criterion under the management control approach then you are required to report emissions from assets for which you have an operating lease.

Please note that if you are defining your organizational boundaries using operational control and are reporting indirect emissions from electricity use in leased office space, you should only report "usable space" (i.e., the space that you have management control of and occupy). Usable space is calculated from the total "rentable space" minus "common space". Common space may include areas such as lobbies and restrooms. See Chapter 6, Section III.6.2 for more information.

Reporting Natural Gas Use for Leased Office Spaces

Organizations that lease buildings or office spaces that are not separately metered for natural gas use are not required to report the direct emissions associated with natural gas use. No member of the California Registry should report estimated direct emissions. All publicly reported direct emissions should be based on directly metered or measured data sources.

You may, however, choose to report estimated natural gas use optionally. If you wish to report your estimated natural gas use optionally, you may use CARROT's emission category: *Optionally Reported* - Subcategory: *Estimated Natural Gas Usage*. This feature allows you to use CARROT's built-in calculation tools, but classifies the data as optional.

Please note that if you are a building owner that occupies only part of a building's usable space, you should report 100% of the emissions from stationary combustion of natural gas for the entire building because you would have both operational and financial control of this emission source.

Table II.2.3 provides guidance on who is required to report emissions from leased assets for various emission sources under each control approach.

II.2.9 Accounting for Structural Changes

Your emissions report should represent a "snapshot" of what your organization's emission sources are at the end of each calendar year. Thus, when structural changes (e.g., mergers, acquisitions, divestitures, outsourcing, and insourcing) occur during the middle of the year, your emissions report should be calculated to reflect that change for the entire year, rather than only for the remainder of the reporting period after the structural change occurred. For example, if your organization acquires a company in June, you should report the emissions from that company for January – December, not June – December. Alternately, if your organization divests a company in June, you should not report any emissions from that company for the entire calendar year.

If emission changes are due to organic growth or decline (building a new facility, shutting down a facility), you must report actual emissions associated with those operations. For instance, should you close a facility in September, you would report the emissions from January to its close.

4 Financial Accounting Standards Board, Statement of Financial Accounting Standards, No. 13. Accounting for Leases. 1976.

Table II.2.3 Reporting Emissions from Leased Assets

Who Reports	Reporting Criteria: Management Control – Operational Control	Reporting Criteria: Management Control – Financial Control	Reporting Criteria: Equity Share	Optionally Reported Emissions
Electricity				
Tenant	✓			
Landlord		✓	✓	
Natural Gas				
Tenant	✓ (if metered individually for tenant's space AND tenant has control of use)			✓
Landlord	✓ (if NOT metered individually for tenant's space)	✓	✓	
HFCs				
Tenant				✓
Landlord	✓	✓	✓	
Mobile Emissions (cars, etc.)				
Vehicle Renters (Company-rented)				✓
Vehicle Lessors (Company-leased)	✓			
Vehicle Owners (Company-owned Vehicles)	✓	✓	✓	
Owners of Personal Vehicles (including personal vehicles used for business purposes)				✓

II.2.10 Examples: Management Control vs. Equity Share Reporting

The following examples are provided to assist you as you determine whether to report using the management control or the equity share basis. Remember, although these examples are provided for individual facilities, you should choose both approaches or either the management control or the equity share approach for your report in its entirety.

Example II.2.1 Companies with Ownership Divided 60%-40%

Company A has 60% ownership and management control, under both the financial and operational control criterion. Company B has 40% ownership of the facility, and does not have management control

Under either criterion for management control, Company A would report 100% of GHG emissions. It has financial control based on its 60% share and there are not other provisions that vest operational control with its minority partner. Under equity share, Company A and Company B would report 60% and 40% of GHG emissions respectively, based on their share of ownership and voting interest.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	60% ownership & voting interest	100%	100%	60%
Company B	40% ownership & voting interest	0%	0%	40%

Example II.2.2 Companies with Ownership Divided 60%-40% and Voting Interests Divided 45%-55%

Company A has 60% ownership of the facility and a 45% voting interest. Company B has 40% ownership of the facility and a 55% voting interest. Company B is also explicitly named as the operator and has the authority to implement its operational and HSE policies. Company B has management control (according to both the financial and operational criteria).

Under management control (either financial or operational criterion), Company B would report 100% of GHG emissions and Company A would report none, because Company B has a majority voting interest. Under equity share, Company A would report 60% of GHG emissions and Company B would report 40%, based on ownership share.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	60% ownership & 45% voting interest	0%	0%	60%
Company B	40% ownership & 55% voting interest	100%	100%	40%

Example II.2.3 Two Companies with 50% Ownership Each

Company A and Company B each have 50% ownership of the facility. Company B has the authority to implement its operational and HSE policies, but all significant capital decisions require approval of both Company A and Company B. Each reports 50% of GHG emissions under the financial criterion of management control and equity share. Under the operational criteria of management control, Company B reports 100% of the facility's emissions while Company A reports 0%.

Example II.2.4 Three Companies with Ownership Divided 55%-30%-15%

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	50% ownership & voting interest	50%	0%	50%
Company B	50% ownership & voting interest	50%	100%	50%

Company A has 55% ownership of the facility, Company B has 30% ownership of the facility, and Company C has 15% ownership. The majority owner has the authority to implement its operational and HSE policies.

Under either criterion of management control, Company A would report 100% of GHG emissions because it holds a majority interest in the control of the facility, and Companies B and C would report no emissions. Under equity share, each company would report according to its equity share of ownership and voting interests.

Participant	Facility	Management Control		Equity Share Reporting
		Financial Reporting	Operational Reporting	
Company A	55% ownership & voting interest	100%	100%	55%
Company B	30% ownership & voting interest	0%	0%	30%
Company C	15% ownership & voting interest	0%	0%	15%

Chapter 3 Operational Boundaries: Required Direct and Indirect Emissions

> **Who should read Chapter 3:**
>
> Chapter 3 applies to all participants.
>
> **What you will find in Chapter 3:**
>
> This chapter provides guidance on determining what direct and indirect GHG emissions your organization must report to the California Registry.
>
> **Information you will need:**
>
> You will need information about the size and nature of GHG-emitting operations throughout your organization in order to determine which emissions are directly and which are indirectly caused by your organization.
>
> **Cross-References:**
>
> It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, and de minimis and significant emissions addressed in Chapter 5.

The next step in compiling your GHG emissions report is to divide your emission sources into emission source categories. Emission sources produce either direct or indirect emissions.

Direct emissions are those emissions from sources that are owned or controlled by your organization. You must report all of your direct emissions. These emissions originate from:

- Mobile combustion sources (e.g., from cars, trucks, rail, air, and other transport) owned or leased by your organization and used for moving raw materials, finished products, supplies, or people;
- Stationary combustion sources used for the production of electricity, steam, or district heating and cooling;
- Process emissions that occur during the production of cement, adipic acid, and ammonia, as well as emissions from agricultural processes; and
- Fugitive sources, for example methane leaks from pipeline systems or leaks of HFCs from air conditioning systems.

Indirect emissions are emissions that occur because of your organization's actions, but are produced by sources owned or controlled by another entity.[1] You should report all of your company's indirect emissions from the following sources:

- Purchased and consumed electricity;
- Purchased and consumed steam; and
- Purchased and consumed district heating or cooling.

You are also encouraged, but not required, to report indirect GHGs from other activities of your organization that produce emissions, but do not fall within your organizational boundary. This could include, for instance, employee commuting and business travel, off-site waste disposal, and other emissions resulting from your demand for goods and services each year. The California Registry currently provides limited guidance for estimating emissions from these optional indirect sources, but identifies some existing tools to help you in this process. More information is available in Chapter 11.

II.3.1 Double Counting Direct and Indirect Emissions

The California Registry recognizes that a company accounting for its indirect emissions may double count the direct emissions from a separate entity. For example, the indirect emissions from electricity use in a participant's inventory double counts the direct emissions from the electricity generator that produced the participant's power. The California Registry requires participants to inventory both direct and indirect emissions to create a comprehensive emissions profile of the entity. This yields a complete picture of the emissions produced by sources owned or controlled by the participant and the emissions produced as a consequence of the participant's activities. The California Registry strives to avoid confusion by requiring participants to report direct and indirect emissions separately.

Double counting direct and indirect emissions does not misrepresent a company's emission profile. It only impacts a company in terms of how the reported information is used. For instance, emissions regulatory regimes could impose limits on emissions that apply to direct or indirect emissions.[1]

1 The GHG Protocol, 2004.

Chapter 4 Establishing and Updating a Baseline

Who should read Chapter 4:

Chapter 4 applies to all participants.

What you will find in Chapter 4:

This chapter considers the options and requirements for determining your organization's baseline.

Information you will need:

You will need information that will help you determine the basis for selecting a baseline year, such as historic emissions data to determine the earliest year (back to 1990) for which you can assemble the required emissions data to complete an emissions report. You will also need to consider any information, if applicable, describing new or recent mergers and acquisitions, divestitures, outsourcing and insourcing of services, and other changes to your organization affecting your total emissions.

Cross-References:

You will need to refer to all applicable chapters relating to quantifying your emissions (Chapters 5-11) in determining your baseline.

II.4.1 Establishing Your Baseline

A baseline is a datum or reference point against which to measure GHG emissions increases and decreases over time. Baselines are used in a regulatory context to establish a clear threshold for compliance and non-compliance. Setting a baseline also allows participants to scale structural changes to their organization back to a benchmark emission profile. This aspect of baselines is called "normalization". For example, as explained below, an acquisition of a company could dramatically increase a participant's emissions relative to previous reporting years. To account for the impact on its emissions profile due to acquisition, a participant would adjust its baseline to incorporate the additional emissions associated with the acquired company, thereby showing that the change in emissions occurred because of structural changes.

Participants select their baseline according to the year that best represents their standard emissions profile. In the context of the California Registry, a baseline is a "base year" that serves as a benchmark to compare emissions produced by an entity over time. The baseline is adjusted to reflect structural changes in your organization.[1] A baseline may also change if there are fundamental changes in generally accepted GHG emissions accounting methodologies.

Although the California Registry strongly encourages participants to set a baseline, you are not required to do so. However, if you choose not to establish a baseline, reviewers of your emission trend might compare successive reporting years back to your first year of reporting, regardless of whether it is indicative of your current structure or operating conditions.

A participant may begin reporting emissions to the California Registry for any year from 1990 forward; likewise it can establish as its baseline any reporting year from 1990 forward. After establishing a baseline participants should report verified emissions results for each subsequent year. If an organization's participation in the California Registry lapses temporarily, it must report emissions for all intervening years upon renewing its participation or establish a new baseline. If its boundaries do not change significantly, the baseline will remain fixed over time.

II.4.2 Rationale for Setting a Baseline

There are several issues to consider when deciding whether to establish a baseline, including:

- **Data certainty** – do you have sufficient data to verify your emissions against the requirements in the General Reporting Protocol for the baseline year?
- **Comparable organizational structure** – is your organization sufficiently comparable in its composition and structure to support a meaningful comparison with the baseline year?
- **Relative emission levels** – which year minimizes or maximizes your emissions relative to most recent levels, and what are the benefits of doing so?

Your baseline should not be adjusted for the organic growth or decline of your organization. Organic growth or decline refers to the increase or decrease in production output, changes in product mix, plant closures, and the opening of new plants that are not the result of changes in the structure of the participant's organization or the result of shifting operations into or out of California or the U.S.

1 In the GRP, baselines refer strictly to entity-level baselines. The GRP does not provide guidance on setting project-level baselines. Participants should refer to the California Registry project protocols for direction on this activity.

Many organizations experience growth and thus their total absolute emissions will increase from year to year, regardless of their organization's operational efficiency. Such organizations, in addition to reporting their total emissions, may also elect to report an efficiency metric, that measures GHG emissions per unit of performance or output compared to the baseline ratio (e.g., CO_2/ft^2 of office space, CO_2/customer, CO_2/kWh, CO_2/$ of revenue, etc.) A list of industry-specific metrics is provided in Appendix F.

II.4.3 Updating Your Baseline

Conditions for Updating Your Baseline

The purpose of a baseline is to compare your organization's emission levels from a point in the past. To allow for this comparison, you must have comparable boundaries over time. If your organization's boundaries change with time, you will need to adjust baseline emissions to permit accurate comparison.[2] This Protocol identifies six circumstances that would require you to update your baseline:

Structural Changes in Your Organization

1. Mergers and acquisitions
2. Divestitures
3. Outsourcing – contracting activities to outside parties that were previously conducted internally
4. Insourcing – conducting activities internally that were previously contracted to outside parties

Shifting of Emissions Sources

5. A shift in the location of an emission source (e.g., due to relocating operations into or out of the U.S. or the State of California, depending on your geographic boundaries)

Improved GHG Accounting Methodologies

6. Fundamental changes in generally accepted GHG emissions accounting methodologies (e.g., significant changes in emission factors or understanding of global warming potential). Please note that you do not need to update your baseline due to changes in electricity emission factors (e.g., switching from eGRID emission factors to utility-specific emission factors or changes in the electricity emission factors between reporting years, as these emission factors are expected to change from year to year based on the power mix for your region)

All required sources of direct and indirect emissions must be included in a participant's entity-wide baseline for reporting and adjustment purposes. However, participants identify and account for direct and indirect emissions separately. Thus, participants may consider tracking both types of emissions separately in terms of a baseline. Both direct and indirect emission baselines are meaningful for the purposes of the California Registry.

2 Participants also have the option to change their baseline at their discretion.

Threshold for Updating a Baseline

For many organizations – particularly large ones – mergers, acquisitions, and divestitures, as well as the other listed organizational changes, are common occurrences. Rather than requiring baseline adjustments whenever any changes occur in your organization, however insignificant, you need only adjust your baseline whenever you estimate that the cumulative effect of such changes affects your organization's total reported emissions by plus or minus 10% relative to the baseline. You may adjust your baseline every year, if you wish. You do not need to adjust your baseline when emissions change by plus or minus 10% at any individual facility unless this facility-level change also affects your total entity emissions by plus or minus 10%.

In some situations, year-to-year changes to total emissions resulting from structural or other changes to your organization may fall below the 10% threshold for updating your baseline. You will need to update your baseline if and when the cumulative effect is greater than 10%. An example of cumulative changes to total emissions is provided in Example II.4.7.

When you specify a baseline, for every year after the baseline year, your verifier will also need to verify that your total emissions have not changed by more than 10% from the baseline due to any cause except organic growth. This is intended to provide a check that you are correctly tracking and reporting the emissions associated with your organization's structure.

Options for Updating a Baseline

For members who have chosen to set a baseline year and who have surpassed the threshold for updating their baseline (plus or minus 10%), there are a few options to consider. You could 1) remove the baseline year and continue to report with no set baseline, 2) remove the baseline year and choose the current year as a new baseline year, or 3) update the baseline year to reflect the cumulative change to your organization. This would require updating and re-verifying all intervening years as well.

Timing for Updating a Baseline

When significant structural changes occur during the middle of the year that trigger a baseline update, your baseline should be recalculated for the entire year, rather than only for the remainder of the reporting period after the structural change occurred. For example, if your organization acquires a company in June, then the emissions associated with the acquisition starting from January 1 of the baseline year should be added to your baseline, not just the emissions from June – December. Similarly, all years following the baseline year, including

the current year emissions (the year that the structural changes occur) should be recalculated for the entire year to maintain consistency with the baseline recalculation.

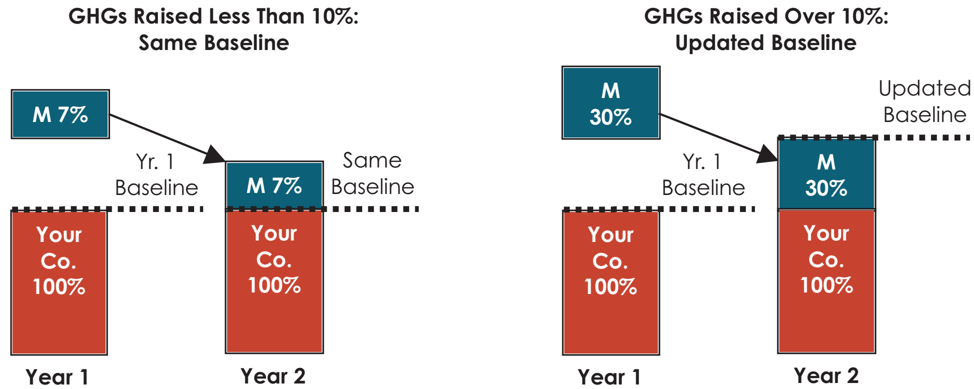
Updating a Baseline for Facilities That Did Not Exist in the Baseline Year

Baseline emissions are not recalculated if your organization makes an acquisition of (or insources) operations that did not exist in its baseline year. There should only be a recalculation of historic data back to the year in which the acquisition came into existence. For instance, if your baseline is 2004 and you acquire a facility in 2008 that began operations in 2006, you would revise your 2006 and 2007 emissions reports to add the associated emissions. However, you would not adjust your 2004 baseline. The same applies to cases where your organization divests (or outsources) operations that did not exist in the baseline year.

II.4.4 Examples: Updating Your Baseline

Example II.4.1 Mergers and Acquisitions

Your organization merges with Mergitrex, raising your total GHG emissions by over 10%.

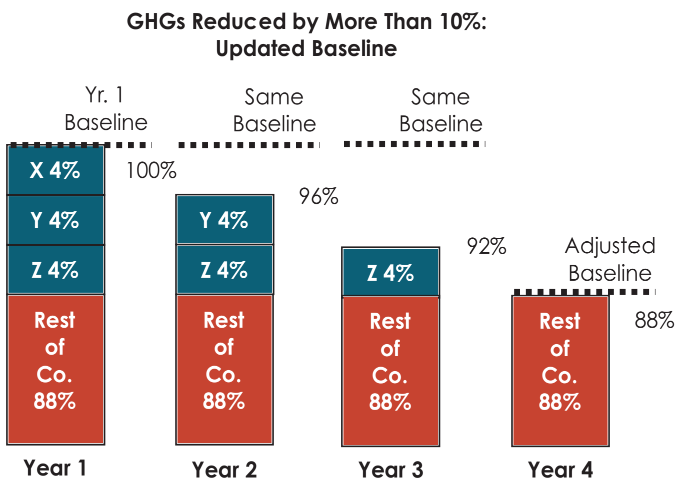


Adjust your baseline emissions to include Mergitrex's baseline emissions (provided Mergitrex existed in your baseline year). If Mergitrex did not exist in the baseline year, do not adjust your baseline emissions. If your merger with Mergitrex led to less than a 10% increase in GHG emissions, do not adjust your baseline emissions unless the acquisition, when combined with other non-organic changes to the organization, changes your annual emissions by more than 10%.

If Mergitrex does not have sufficient data to establish baseline emissions for your organizations baseline year, you will need to select a new baseline year for which both companies have sufficient data to allow the baseline emissions to be verified.

Example II.4.2 Divestitures

Your organization divests three divisions over the second, third, and fourth reporting years. Each of these divisions account for 4% of your GHG emissions, for a 12% total reduction in emissions by year four.



Because the cumulative effect of these divestitures reduces your company's emissions by more than 10% in year four, you will need to adjust your baseline by subtracting the emissions of the three divisions from those reported during your baseline year and adjust the baseline accordingly.

Example II.4.3 Outsourcing

Your organization contracts out activities previously included in your baseline.

If your organization contracts out activities previously included in its baseline inventory, you should treat these activities similar to a divestiture. Emissions associated with the outsourced activity should now be reported as optional emissions and subtracted from the baseline emissions. If this shift affects your emissions by more than 10%, you should adjust your baseline. There is no need to adjust your baseline for outsourcing of activities that did not exist during your baseline year. As part of your annual GHG emissions reporting, you will attest that your organization has not outsourced any emissions, or, if you have, that these emissions have been subtracted from your baseline or that they fall below the minimal level.

Example II.4.4 Insourcing

Your organization begins to conduct business activities not previously included in its baseline inventory.

Insourcing is the converse of outsourcing. You should treat these activities as an acquisition. Emissions associated with the insourced activity should be reported as direct or indirect depending on the owner of the emissions and not included with optional emissions. If this shift affects your emissions by more than 10%, you should adjust your baseline. You should not adjust the baseline for insourcing of activities that began after your baseline year.

Example II.4.5 Shifting the Location of Emissions Sources

Your organization moves operations out of or into California or the U.S.

If you shift operations outside of California, which reduces the sum of your direct and indirect emissions by 10% or more, subtract the emissions of the shifted operations from your baseline. Shifts of operations into California of 10% or more should be addressed by increasing your baseline to include emissions from those operations. A U.S. baseline should be adjusted similarly for shifts of operations outside or into the U.S. Where you identify leakage or shifting of emissions—where reducing emissions at one location leads to an increase of emissions at another location—because of shifts in the location of your emission sources, you should document the estimated impacts in your annual movement report.

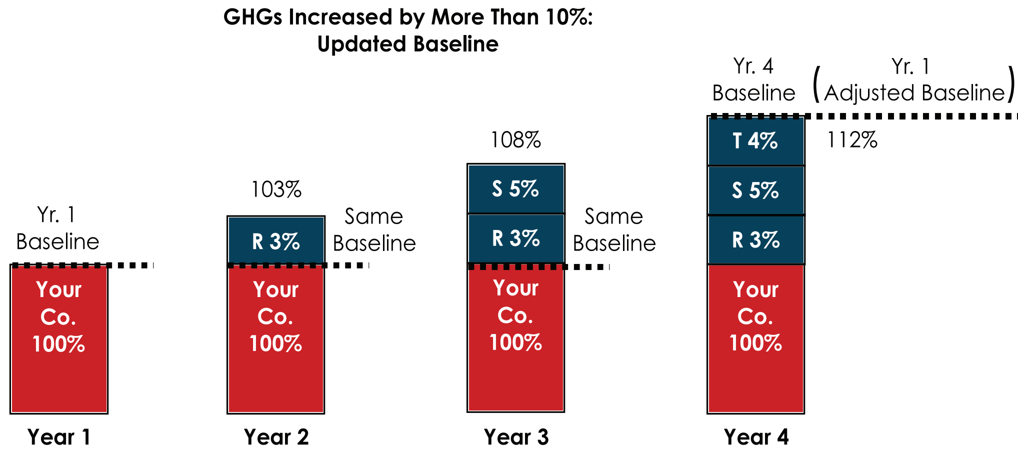
Example II.4.6 Change in Emissions Accounting Methodologies

Your organization employs a new methodology that is approved by the California Registry.

Your baseline emissions should be recalculated for any changes in calculation methodologies if such changes will alter your total emissions in the current reporting year more than 10%. This ensures a comparative time-series of emission estimates.

Example II.4.7 Cumulative Changes to Total Emissions

Your organization acquires three companies over three years, raising your GHG emissions by 12%.



Your company acquires Reyes Rockets, Sierra Spaceworks, and Trinity Telescopes in reporting years two, three, and four representing GHG emission increases of 3%, 5%, and 4%, respectively. While these acquisitions individually represent less than the required 10% increase for a baseline adjustment, they amount to a 12% cumulative increase in total emissions. Thus, you would be required to update your baseline in year four (assuming each company existed in your baseline year).


Part III Quantifying Your Emissions

Having determined your geographic, organizational, and operational boundaries and your emission baseline (if you choose to have one), you are ready to begin estimating your organization's overall emissions. For many participants, the only significant emissions of GHGs you will have to report are indirect emissions from the purchase and consumption of electricity. Thus, this Protocol begins its series of emissions estimation methods with indirect emissions from electricity consumption. Next, it provides guidance for the next most common emission sources for participants: direct emissions from mobile sources. The following chapters provide guidance on calculating emissions from other required sources and optional sources.

Part III provides you with the technical methodologies needed to quantify the GHG emissions you will be reporting to the California Registry.

Chapter 5 provides an explanation of de minimis and significant emissions. De minimis emissions represent a quantity of GHG emissions from one or more sources and one or more gases, which, when summed, equal less than 5% of your organization's total emissions.

Chapters 6 though 11 provide estimation methods for the following categories of emissions:

- Chapter 6 – Indirect Emissions from Grid-Delivered Electricity Use
- Chapter 7 – Direct Emissions from Mobile Combustion
- Chapter 8 – Direct Emissions from Stationary Combustion
- Chapter 9 – Indirect Emissions from Imported Steam, District Heating or Cooling and Electricity from a Co-Generation Plant
- Chapter 10 – Direct Emissions from Manufacturing Processes
- Chapter 11 – Direct Fugitive Emissions

Chapter 12 provides guidance on efficiency metrics and reporting emissions outside of your entity's influence, which the California Registry considers Optional Reporting.

Chapter 5 De Minimis Emissions and Significance

> Who should read Chapter 5:
>
> Chapter 5 applies to all participants.
>
> What you will find in Chapter 5:
>
> This chapter provides guidance on determining what emissions are significant, what emissions can be classified as de minimis, and estimating de minimis emissions.
>
> Information you will need:
>
> You will need information about the size and nature of GHG-emitting operations throughout your organization, particularly to be able to identify emissions sources that would amount to less than 5% of your company's total emissions.
>
> Cross-References:
>
> It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, respectively, operational boundaries considered in Chapter 3, and all relevant quantification issues raised in Chapters 6-11.

The rules, methodologies, and standards in this Protocol are designed to support the reporting of GHG emissions in a manner that minimizes the reporting burden and maximizes the benefit of standardized GHG emissions data.

III.5.1 Understanding De minimis and Significant Emissions

For the purposes of this Protocol, de minimis emissions are a quantity of GHG emissions from any combination of sources and/or gases, which, when summed equal less than 5% of your organization's total emissions. Significant emissions are any emissions of GHGs that are not de minimis in quantity when summed across all sources of your organization.

For many participants, identifying and quantifying all of their GHG emissions according to the methodologies presented in this Protocol would be unduly burdensome and not cost-effective. Some participants may operate hundreds, if not thousands, of small facilities where the known emissions—including, for example, indirect emissions from electricity consumption or direct emissions from motor vehicle operation—are a small fraction of larger emissions sources from industrial activities. To reduce the reporting burden, the California Registry requires that entities calculate at least 95% of their emissions according to the Protocol's methodologies. Thus, if necessary, up to 5% of emissions can be classified and reported as de minimis. However, the California Registry strongly encourages entities to report 100% of their emissions according to the methodologies laid out in the Protocol when possible.

III.5.2 Rationale for Calculating De Minimis Emissions

You must identify and report all sources of emissions in your inventory. For significant sources, you must calculate these emissions using required methodologies. For insignificant sources (i.e., potential de minimis sources), you may use a rough, upper bounds estimate to determine the amount of emissions that are de minimis. In the first year, you need to identify what sources fall into the de minimis pool and their estimated total emissions. This information must be disclosed in your emissions report, and reviewed and accepted by your verifier. In subsequent years, if these emissions do not change significantly, you can hold these assumptions constant and your verifier may not need to re-examine your estimates. However, you must continue to report your de minimis sources in CARROT each year.

For example, a participant estimates they emit about 1,000 metric tons of CO_2 each year. Most of these emissions come from an on-site heating and cooling system that services their buildings. In addition, this participant also has one company car that is driven about 20,000 miles each year. This participant estimates that between 800 and 1,000 gallons of gasoline are consumed by this car each year. Taking the upper estimate of 1,000 gallons, the participant calculates the emissions from this source as 8.8 metric tons of CO_2/year, and finds that this amount falls below the de minimis threshold of 5% or 50 tons CO_2/year.

The participant can report this emission source as de minimis in CARROT and provide this estimation to the verifier, along with vehicle records showing the actual miles traveled of the car. In subsequent years, where the operation patterns do not change significantly, the participant can continue to declare the emissions from this source de minimis, and will need to re-calculate this information only every three years.

You may use alternative methods to demonstrate that emissions are de minimis. For example, if your emissions

come only from electricity and fuel consumption, it would be sufficient to show that the emission factors for methane and nitrous oxide, when multiplied by their global warming potentials and added together, are less than 5% of the corresponding emission factor for carbon dioxide. Assuming you deemed no other type of emissions to be de minimis, the total de minimis emissions would be less than the 5% threshold. You should base your de minimis assumptions on the IPCC 's Second Assessment Report (SAR) global warming potential values.

Your estimations and assumptions in calculating your de minimis emissions will need to be disclosed in your emissions report and provided to and verified by your verifier. If your operations do not change significantly from year to year, you will only need to re-calculate and have verified your de minimis emissions every three years.

III.5.3 Identifying De Minimis Emissions

The sources and gases that will be de minimis will vary from participant to participant. For example, fugitive GHG emissions may be de minimis for many participants but will likely be significant for participants involved in the transportation and distribution of natural gas. Similarly, many participants may choose to select non-CO_2 gases as de minimis since non-CO_2 gas emissions are not significant for many operations.

As demonstrated in the examples on the following pages, you have some discretion in identifying sources as de minimis. As Examples III.5.1 and III.5.2 demonstrate, there may be instances where you identify multiple sources as de minimis, which, when added together, equal less than 5% of your emissions. Example III.5.3 illustrates how emissions of different kinds of gases can also be considered de minimis if their combined total is less than 5% of your overall emissions.

III.5.4 Using CARROT to Document De Minimis Emissions

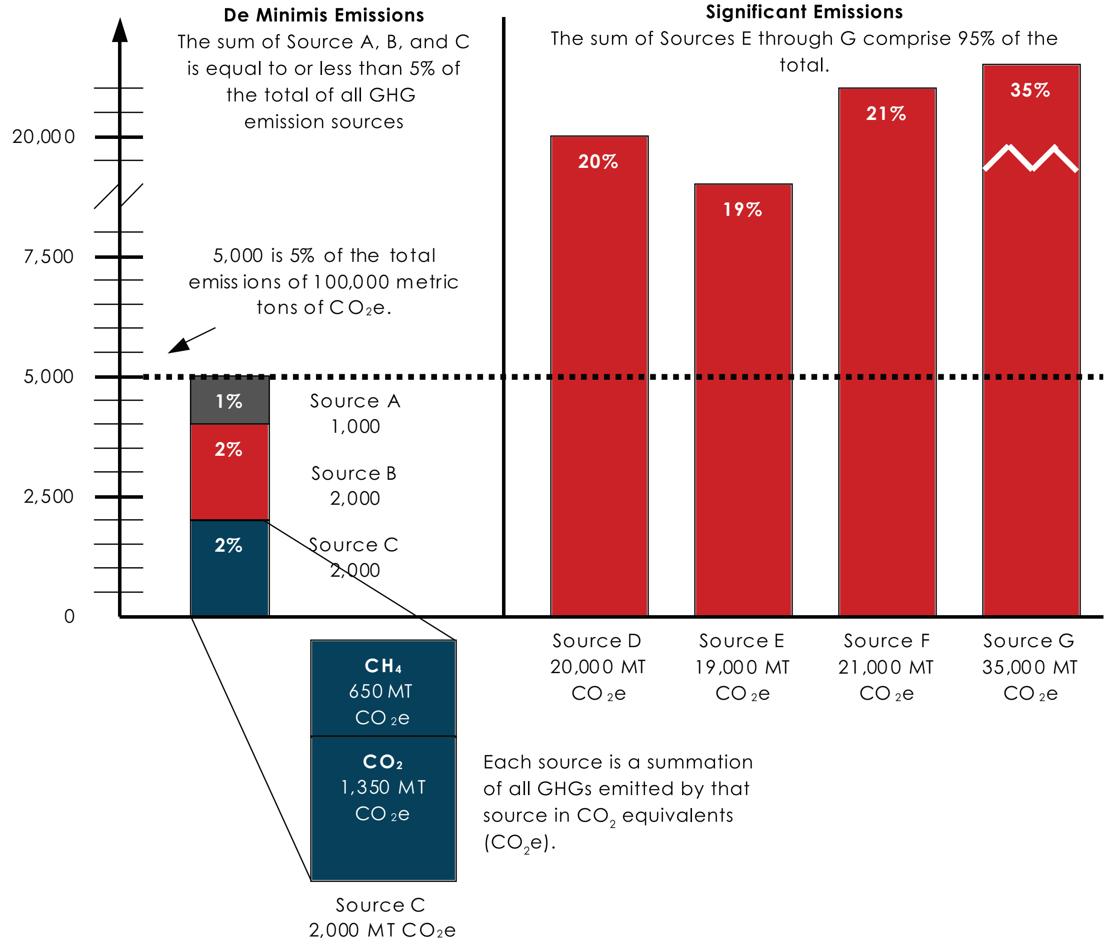
CARROT helps you to calculate and track your de minimis emissions over time. In the first year you report using CARROT, you will enter information to calculate all of your emissions. Once you have reported your inventory, you can designate any combination of individual sources or gases as de minimis. CARROT will then track this information for you, and report it in a category separate from the rest of your emissions.

III.5.5 Examples: Determining De Minimis

Example III.5.1 All Small Sources are De Minimis

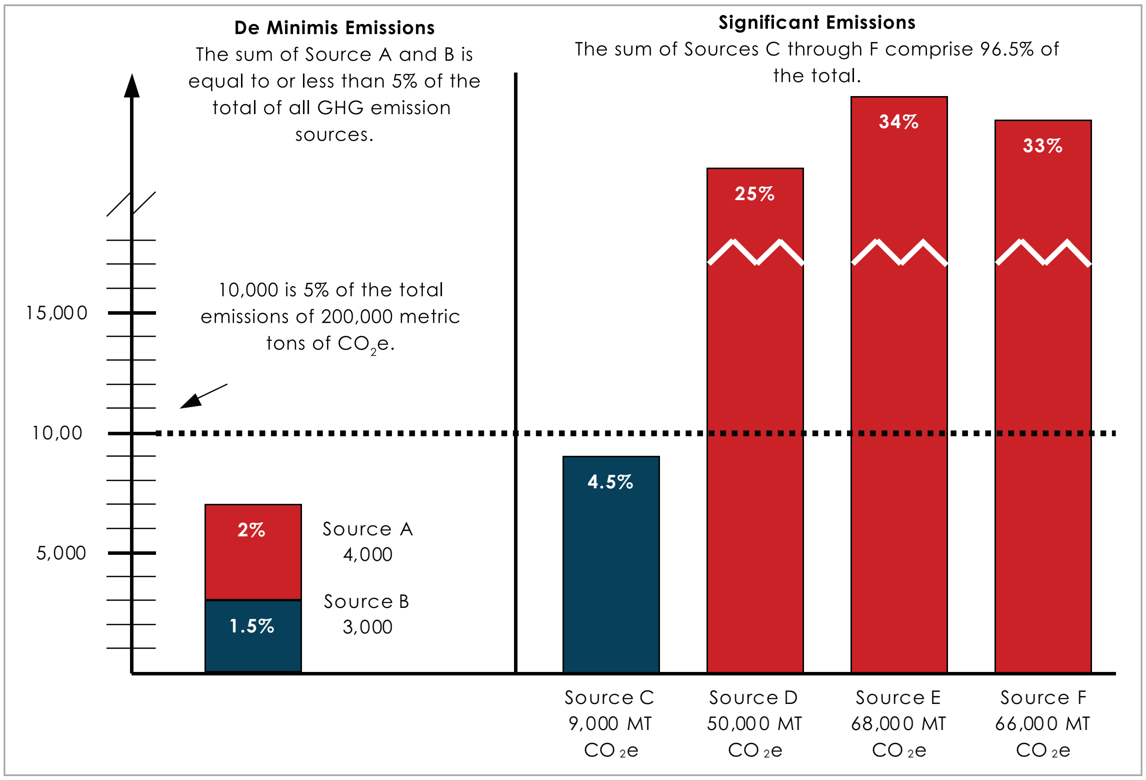
Your company intends to report GHG emissions from seven sources (A through G). You have calculated your total GHG inventory (including de minimis emissions) to determine the 5% threshold. Your total emissions inventory from all seven sources is 100,000 metric tons CO_2e. Therefore, the 5% de minimis threshold is 5,000 metric tons CO_2e. This means that you can decide which 5,000 metric tons of emissions you want to classify as de minimis.

The sum of the GHG emissions from Source A, Source B, and Source C is equal to 5% of your company's total emissions or 5,000 metric tons. As a result, you may choose to report emissions from Source A, Source B, and Source C as de minimis sources. Note, however, that each source is the sum of all GHGs emitted for that source. For example, Source C is a combination of 1,350 metric tons CO_2 and 650 metric tons of CO_2 e from methane, for a total of 2,000 metric tons of CO_2e.



Example III.5.2 Choosing Between Small Sources for De Minimis

Your company intends to report GHG emissions from 6 sources. You have estimated that your total GHG emissions inventory from all 6 sources, including de minimis sources, is 200,000 metric tons of CO_2e. Therefore, your 5% threshold is 10,000 metric tons of CO_2e. You have three sources, Source A, Source B, and Source C, that are each below the 5% threshold. However, you will need to select a combination of sources that, when added together, are less than or equal to the 5% threshold. For example, you may choose to classify Source A and Source B as de minimis. Likewise, you could also choose to classify only Source C as de minimis.



Example III.5.3 Different Sources of CO_2 and CH_4 Emissions are De Minimis

Your company plans to report both carbon dioxide and methane emissions from four sources. You have estimated your total GHG emissions from all four sources at 100,000 metric tons of CO_2e. The emissions from the four sources are as follows:

Source	CO_2 Emissions (metric tons)	CH_4 Emissions (metric tons CO_2e)	Total Source Emissions (metric tons CO_2e)
Source 1	39,900	**100**	40,000
Source 2	29,900	**100**	30,000
Source 3	19,900	**100**	20,000
Source 4	**3,000**	7,000	10,000
Total			100,000
De Minimis Threshold			5,000
De minimis emissions = 3,300 Significant emissions = 96,700			

Chapter 6 Indirect Emissions from Electricity Use

> **Who should read Chapter 6:**
>
> Chapter 6 applies to all participants. Any organization that purchases and consumes electricity from an electric utility should complete this chapter.
>
> **What you will find in Chapter 6:**
>
> This chapter provides guidance on calculating your indirect emissions from electricity consumption.
>
> **Information you will need:**
>
> Organizations will simply need to refer to monthly utility electricity bills for information about electricity consumed.
>
> **Cross-References:**
>
> This chapter may be useful in completing Chapter 9 on quantifying indirect emissions from co-generation, steam or district heating and cooling.

III.6.1 Calculating Indirect Emissions from Electricity Use

Nearly all companies are likely to have some indirect emissions associated with the purchase and use of electricity. In some cases, indirect emissions from electricity use may be the only GHG emissions that a company will have to report. To calculate indirect emissions from electricity use, you should follow this simple five-step process:

1. Determine your annual electricity use in each applicable state or region where you have operations;
2. Select the appropriate electricity emission factors that apply to the electricity source used;
3. Determine your total annual emissions in metric tons;
4. Convert non-CO_2 gases to carbon dioxide equivalent (CO_2e); and
5. Total the sum of all CO_2 and CO_2e gases emitted from electricity use.

The generation of electricity through the combustion of fossil fuels typically yields carbon dioxide and, to a much smaller extent, nitrous oxide and methane. This Protocol provides annual emission factors for all three.

Step 1: Determine annual electricity consumption.

Reporting indirect emissions from electricity consumption begins with determining annual electricity use. The preferred method for establishing annual electricity use relies on the energy use information provided by the electric utility company. A participant's monthly utility bills contain the number of kilowatt-hours consumed. A kilowatt-hour (kWh) is a measure of the energy used by electric loads, such as lights, office equipment, air conditioning or machinery.

Depending on the organization of your company and its facilities, you may need to aggregate multiple electricity bills. Collect your monthly bills and record the kilowatt-hours consumed each month. Then, add together your total kWh per state for the year.

If your electric bill does not begin or end exactly on January 1 and December 31, but spans two calendar years, you must pro-rate your electricity use to properly quantify the emissions for the calendar year being reported; refer to Equation III.6a.

Equation III.6a **Monthly Electricity Use**

$$\text{Electricity Use (kWh)} = \left(\text{Electricity Use (kWh) in Period Billed} \div \text{Number of Days in Period Billed} \right) \times \text{Number of Days of Bill Period}$$

To calculate your emissions for January from an electric bill spanning December and January, first, divide your total kilowatt-hours used by the number of days in your billing cycle. Then, calculate the number of days from your bill that fall in January. Multiply the electricity use per day by the number of days in January.

If an organization is unable to obtain energy use information from the utility, the California Registry offers three alternative methodologies for estimating energy consumption. Instructions for following these approaches are provided in Section III.6.2.

Step 2: Select electricity emission factors applicable to the area where the energy was consumed.

An electric grid emission factor represents the amount of GHGs emitted per unit of electricity consumed from the electricity transmission and distribution system, and is reported in pounds per kilowatt-hour or megawatt-hour (lbs/kWh or /MWh). However, as a practical matter it is often very difficult to determine the exact fuel source for your electricity.

Thus, regional/power pool emission factors for electricity consumption can be used to determine emissions based on electricity consumed. If you can obtain verified emission factors specific to the supplier of your electricity, you are encouraged to use those factors in calculating your indirect emissions from electricity generation. If your electricity provider reports an electricity delivery metric under the California Registry's Power/Utility Protocol, you may use this factor to determine your emissions, as it is more accurate than the default regional factor. Utility-specific emission factors are available in the Members-Only section of the California Registry website and through your utility's Power/Utility Protocol report in CARROT.

This Protocol provides power pool-based carbon dioxide, methane, and nitrous oxide emission factors from the U.S. EPA's eGRID database (see Figure III.6.1), which are provided in Appendix C, Table C.2. These are updated in the Protocol and the California Registry's reporting tool, CARROT, as often as they are updated by eGRID.

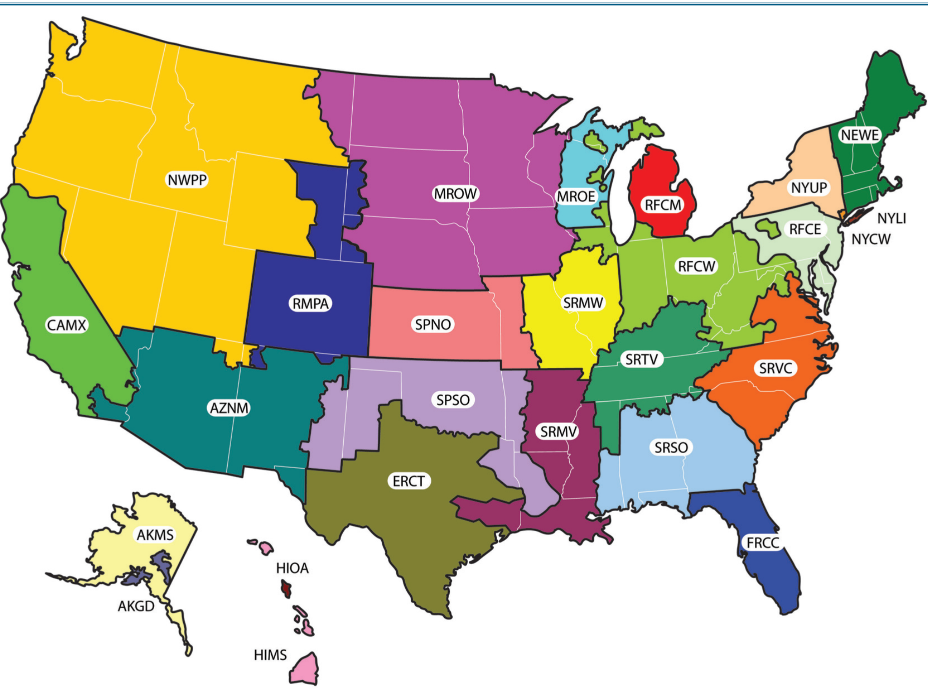
To look up your eGRID subregion using your zip code, please visit U.S. EPA's "Power Profiler" tool at www.epa.gov/cleanenergy/energy-and-you/how-clean.html.

Fuel used to generate electricity varies from year to year, so emission factors also fluctuate. When possible, you should use emission factors that correspond to the calendar year of data you are reporting. CO_2, CH_4, and N_2O emission factors for historical years are available in Appendix E. If emission factors are not available for the year you are reporting, use the most recently published figures.

U.S. EPA Emissions and Generation Resource Integrated Database (eGRID)

The Emissions & Generation Resource Integrated Database (eGRID) provides information on the air quality attributes of almost all the electric power generated in the United States. eGRID provides search options, including information for individual power plants, generating companies, states, and regions of the power grid. eGRID integrates 24 different federal data sources on power plants and power companies, from three different federal agencies: EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Emissions data from EPA are combined with generation data from EIA to produce values like pounds per megawatt-hour (lbs/MWh) of emissions, which allows direct comparison of the environmental attributes of electricity generation. eGRID also provides aggregated data to facilitate comparison by company, state or power grid region. eGRID's data encompasses more than 4,700 power plants and nearly 2,000 generating companies. eGRID also documents power flows and industry structural changes.
www.epa.gov/cleanenergy/egrid/index.htm.

Figure III.6.1 eGRID Subregions



Source: eGRID2007 Version 1.1, December 2008 (Year 2005 data).

Step 3: Determine total annual emissions and convert to metric tons.

Multiply your electricity use in kilowatt-hours from Step 1 by the emission factors for CO_2, CH_4, and N_2O from Step 2. To convert pounds into metric tons, divide the total by 2204.62 lbs/metric ton. (See Equation III.6b.) Repeat this step for each region in which you purchased electricity.

Equation III.6b	Total Emissions from Indirect Electricity Use					
Total CO_2 Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs CO_2/kWh)	÷	2,204.62 lbs/metric ton
Total CH_4 Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs CH_4/kWh)	÷	2,204.62 lbs/metric ton
Total N_2O Emissions (metric tons)	=	Electricity Use (kWh)	x	Electricity Emission Factor (lbs N_2O/kWh)	÷	2,204.62 lbs/metric ton

Step 4: Convert non-CO_2 emissions to CO_2e and sum the total.

To incorporate non-CO_2 gases into your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO_2 equivalent. To do this, multiply the non-CO_2 GHG emissions in units of mass by its global warming potential (GWP). Table C.1 in Appendix C lists the 100-year GWPs to be used to express emissions on a CO_2 equivalent basis. Equation III.6c shows the calculation to determine CO_2e from the total mass of a given non-CO_2 GHG using the GWPs published by the IPCC in its Second Assessment Report (SAR, 1996). If you use CARROT to calculate your emissions, it will automatically perform this calculation for you. Sum your CO_2 + CO_2e emissions (see Equation III.6d).

Equation III.6c	Convert Non-CO_2 GHGs to Carbon Dioxide Equivalent and Sum Total					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2					=	1,237.61 metric tons CO_2
CH_4 Tons of CO_2e	=	0.03347 metric tons CH_4	x	21 (GWP)	=	0.70287 metric tons CO_2e
N_2O Tons of CO_2e	=	0.01644 metric tons N_2O	x	310 (GWP)	=	5.0964 metric tons CO_2e
				Total	=	1,243.41 metric tons CO_2e

Equation III.6d	Total GHG Emissions from Electricity Use			
Total CO_2e Emissions (metric tons)	=	Total CO_2 Emissions (metric tons)	+	Total CO_2e Emissions (metric tons)

III.6.2 Alternate Methods to Estimate Electricity Use

Some organizations have difficulty reporting their indirect emissions from purchased electricity because their electricity use is not separately metered. As previously mentioned, these organizations must still calculate and report their estimated indirect emissions. To calculate their electricity use, such organizations have four options:

1. Estimate energy use based on a participant's share (percent of square footage) of the building in which they are using energy and the building's total annual electricity consumption.
2. Estimate energy use based on an energy audit.
3. For office space in California only, estimate energy use based on square footage and the average annual electricity intensity in your service territory.
4. Estimate energy use based on square footage and average electricity intensity of comparable facilities.

Reporters who cannot obtain actual electricity meter readings should clearly indicate, both to their verifier and in their public CARROT report, which methodology was used to estimate their indirect emissions from purchased electricity.

Methodology Disclosure

All members using an alternate estimation methodology must disclose publicly in CARROT that they are unable to obtain their electric bills and are estimating their emissions.

The California Registry asks that members use the following standard disclosure language in their public CARROT report:

"[Some or all] of the indirect emissions from purchased electricity disclosed in this report are estimated based on a California Registry-approved methodology for estimating electricity use, not calculated based on metered data."

Rentable Space vs. Usable Space

Depending on which of the alternate methodologies you use, you may be required to identify the square footage of your operations and the total square footage of your building. It is important to identify, through your lease and with your landlord, your usable square footage, not your rentable square footage.

Rentable square footage is the usable square footage plus the tenant's pro-rata share of the building common areas, such as the lobby, public corridors, and restrooms. Usable square footage is the area contained within the walls of the tenant space (i.e., the space you occupy).

Tenants of leased space typically do not have control over electricity usage or temperature in common space areas, hence it does not fall within your management control. Consequently, common space should not be included in your square footage calculations. You should only estimate the indirect emissions from purchased electricity for the usable square footage of the space that you occupy.

Method 1 – Leased Space

The following steps provide instructions on how to arrive at an estimate of energy use by determining your proportion of the building's total energy use.

Step 1: Determine your building's total annual electricity consumption.

Collect your building's monthly electricity bills and record the kilowatt-hours consumed each month. Then, add together the total kWh for the year.

If your electric bill does not begin or end exactly on January 1 and December 31, but spans two calendar years, you must pro-rate your electricity use to properly quantify the emissions for the calendar year being reported; refer to Equation III.6a.

Alternatively, if the building is unwilling to provide you with the electricity bills, you can request an attestation from the building owner/manager regarding the building's annual energy usage and usable square footage.

Step 2 Calculate your organization's share of total building electricity consumption.

Next, you must identify your organization's total usable square footage occupied and determine what percentage this is of the building's total usable square footage. Multiply this percentage by the building's total annual electricity consumption.

Step 3: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factor for your state or power pool.

Step 4: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors (SAR) from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Method 2 – Energy Audit

Companies that choose to estimate their electricity use through an energy audit should consult with the California Registry in order to receive approval for its methodology.

Method 3 – Office Space in California Only

Please note that this methodology is applicable for leased office space located within California only. If you are unable to obtain information about your building's total energy use, follow these steps to estimate your emissions based on your square footage.

Step 1: Determine your office space's usable square footage.

Review your lease, which should include your square footage information.

Step 2: Determine which electric utility services your building.

Contact your property management company to request the name of the provider. If you cannot obtain this information from your property management company, consult your local utility to confirm the electricity provider for your office.

Step 3: Determine the average annual electricity intensity in your service territory.

Average electricity intensity, broken out by small and large offices, is available for four of California's largest utilities. (Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and San Diego Gas & Electric (SDG&E)) from the California Energy Commission. These are summarized below:

	Annual Electricity Intensity (kWh/ft²)			
	PG&E	SCE	SDG&E	SMUD
Small Office (<30,000 ft²)	13.49	13.25	12.13	12.41
Large Office (>30,000 ft²)	16.77	17.91	19.23	19.95

Source: California End-Use Survey, California Energy Commission, March 2006. http://www.energy.ca.gov/ceus/index.html)

If your office location does not fall into one of these utility service areas, use the electricity intensity for the service area closest to your office location.

Step 4: Calculate your office's electricity consumption.

Equation III.6e	Estimated Annual Electricity Comsumption			
Usable Office Space (ft²)	x	Annual Electricity Intensity (kWh/ft²)	=	Your estimated annual electricity consumption (kWh)

Step 5: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factors that are available for your state or power pool.

Step 6: Determine total annual emissions and convert to metric tons.

Multiply your estimated electricity use in kilowatt-hours from Step 4 by the emission factors for CO_2, CH_4, and N_2O from Step 5. To convert pounds into metric tons, divide the total by 2,204.62 lbs/metric ton (see Equation III.6b).

Step 7: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors from Appendix C, Table C.1 (SAR) to convert CH_4 and N_2O to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Method 4 – Comparable Facilities

Where electricity records are not available and total annual electricity consumption of your operations is unknown, you can estimate electricity use based on the size of your space and function of the facility.

Use the following steps to estimate the electricity use at your operations:

Step 1: Determine your operations' usable square footage.

Review your lease, which should include your square footage information.

Step 2: Identify comparable facilities with known annual electricity use rates and usable square footage.

If possible, these facilities should be owned or operated by your organization. You should consider the primary function of the facility and the primary uses of electricity at each facility. You may also consider the age, hours of operation, number of occupants, and the type of heating and cooling systems employed in the buildings.

If electricity consumption for another comparable space owned or operated by your organization is not available, average energy intensity by principal building activity is available from the U.S. Energy Information Administration Commercial Building Energy Consumption Survey (CBECS). This information is summarized in Table III.6.1. In order to determine the appropriate principal building activity, consult CBECS' definitions at www.eia.doe.gov/emeu/cbecs/building_types.html.

Step 3: Determine electricity used per square foot at the comparable facility.

Divide the annual electricity use at the comparable facility by its usable square footage to obtain its annual electricity intensity (kWh/ft²).

Step 4: Calculate your office's electricity consumption.

Multiply the energy intensity metric calculated in Step 3 or the appropriate metric from Table III.6.1 by the usable square footage of the space for which you are estimating the electricity use (see Equation III.6e).

Step 5: Select electricity emission factors that apply to your region and multiply by electricity use.

Obtain the best available electricity emission factors for your location.

Step 6: Determine total annual emissions and convert to metric tons.

Multiply your estimated electricity use from Step 4 by the emission factors for CO_2, CH_4, and N_2O you identified in Step 5. Then multiply the total by 2,204.62 lbs/metric ton (see Equation III.6b).

Step 7: Convert non-CO_2 emissions to CO_2e and sum the total.

Use the global warming potential factors from Appendix C, Table C.1 (SAR) to convert CH_4 and N_2O to carbon dioxide equivalent. Sum all gases (see Equation III.6c and III.6d).

Table III.6.1 Annual Electricity Intensity Based On Principal Building Activity

Principal Building Activity	Annual Electricity Intensity (kWh/ft²)
Education	11.0
Food Sales	49.4
Food Service	38.4
Health Care	22.9
Inpatient	27.5
Outpatient	16.1
Lodging	13.5
Retail (Other Than Mall)	14.3
Office	17.3
Public Assembly	12.5
Public Order and Safety	15.3
Religious Worship	4.9
Service	11.0
Warehouse and Storage	7.6
Other	22.5
Vacant	2.4

Source: Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey (CBECS): Consumption and Expenditures Tables, Table C14. Electricity Consumption and Expenditures Intensities for Non-Mall Buildings, 2003 (December 2006).

Optional Reporting:
Recognizing the Benefits of Green Power and Renewable Energy Certificates Purchases

The California Registry recommends participants use the following guidance to show how grid-related green power purchases and renewable energy credits (REC) impact indirect emissions estimates from electricity consumption. This information can be reported in the optional section of your annual emissions report, which will not be reviewed by your third-party verifier. The objective in providing guidance for optional reporting is to facilitate consistency and transparency in how renewable energy purchases are accounted for and reported in GHG inventories. The procedure below uses a line-item adjustment of your indirect emissions from electricity consumption to reflect the impact of your renewable energy purchases.*

Step 1: Distinguish and classify the type of renewable energy purchase.

Your renewable energy purchases will come either from your participation in a green power program (offered by an electric utility or an independent power provider), or from your direct purchase of RECs.

Step 2: Itemize total renewable energy purchases by type.

For each type of renewable energy purchase, determine the total kWh bought and record separately. The renewable power generated should occur within the same year as the scope of your report.

Step 3: Select the electricity emission factor(s) from Appendix C, Table C.2 that apply to the area in which the renewable power was generated.

If you bought renewable energy through a green power program, the California Registry recommends that you contact your green power program administrator for information on determining the geographic origin of renewable energy. REC purchases should have this information in the purchase agreement. The California Registry recommends that you determine the carbon dioxide impact as well as methane and nitrous oxide. Therefore, you should select an emission factor from Appendix C that corresponds to each gas.

Step 4: Multiply the total renewable energy purchase, by type, by the emission factor(s) selected in Step 3, convert non-CO_2 emissions to CO_2e, and sum the total.

Use the global warming potentials in Table C.1, Appendix C to convert non-CO_2 emissions to CO_2e. Add together the CO_2e emissions from the two types of purchases to determine total emissions.

Step 5: Subtract the total emissions from renewable energy purchases from the total indirect emissions from electricity consumption calculated in III.6.1 or III.6.2.

A line-item adjustment of your total indirect emissions from electricity consumption will show the positive impact associated with purchasing renewable energy through a green power program or from purchasing RECs.

You should disclose, to the maximum extent possible, the type of resource that generated the renewable power in the purchase agreement. EPA's Green Power Program provides additional information on what qualifies as an eligible or new renewable resource (see www.epa.gov/greenpower).

* The California Registry's recommended approach is consistent with EPA's current guidance for reporting purchases of green power and renewable energy certificates.

III.6.3 Example: Indirect Emissions from Electricity Use

Costlo Clothing Distributors

Costlo is a discount retail clothing chain with two outlets in Los Angeles, California, one in Portland, Oregon, and one in Tucson, Arizona. The company only purchases electricity and has no other GHG emissions.

Step 1: Determine annual electricity consumption.

Step 2: Select electricity emission factors that apply to the electricity purchased.

Because emission factors for electricity vary from region-to-region, Costlo tracks its electricity purchases by utility providing the electricity.

Annual Electricity Emissions and Emissions Factors

Region/ State	Power Generator	Annual Electricity Purchases (MWh)	CO_2 lbs/MWh	CH_4 lbs/MWh	N_2O lbs/MWh
CAMX/ California	Los Angeles	1,600	724.12	0.0302	0.0081
NWPP/Oregon	Portland	600	902.24	0.0191	0.0149
AZNM/Arizona	Tucson	800	1,311.05	0.0175	0.0179

Step 3: Determine total annual emissions and convert to metric tons.

Equation III.6b	Total Carbon Dioxide, Methane, and Nitrous Oxide Emissions for Electricity Use from Each Utility							
Los Angeles, CA	=	1,600 MWh	x	724.12 (lbs/MWh)	÷	2,204.62 lbs/mt	=	525.53 mt CO_2
Portland, OR	=	600 MWh	x	902.24 (lbs/MWh)	÷	2,204.62 lbs/mt	=	245.55 mt CO_2
Tucson, AZ	=	800 MWh	x	1,311.05 (lbs/MWh)	÷	2,204.62 lbs/mt	=	475.75 mt CO_2
						Subtotal	=	1,246.83 mt CO_2
Los Angeles, CA	=	1,600 MWh	x	0.0081 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00588 mt N_2O
Portland, OR	=	600 MWh	x	0.0149 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00406 mt N_2O
Tucson, AZ	=	800 MWh	x	0.0179 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00650 mt N_2O
						Subtotal	=	0.01644 mt N_2O
Los Angeles, CA	=	1,600 MWh	x	0.0302 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.02192 mt CH_4
Portland, OR	=	600 MWh	x	0.0191 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00520 mt CH_4
Tucson, AZ	=	800 MWh	x	0.0175 (lbs/MWh)	÷	2,204.62 lbs/mt	=	0.00635 mt CH_4
						Subtotal	=	0.03347 mt CH_4

Step 4: Convert Non-CO_2 emissions to CO_2e and sum the total. Use Equation III.6c and III.6d.

Equation III.6c	Convert Non-CO_2 GHGs to Carbon Dioxide Equivalent and Sum Total					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2					=	1,246.83 metric tons CO_2
CH_4 Tons of CO_2e	=	0.03347 metric tons CH_4	x	21 (GWP)	=	0.70287 metric tons CO_2e
N_2O Tons of CO_2e	=	0.01644 metric tons N_2O	x	310 (GWP)	=	5.0964 metric tons CO_2e
				Total	=	1,252.63 metric tons CO_2e

Chapter 7 Direct Emissions from Mobile Combustion

> **Who should read Chapter 7:**
>
> Chapter 7 applies to all participants that operate motor vehicles or other forms of transportation.
>
> **What you will find in Chapter 7:**
>
> This chapter provides guidance on calculating your direct emissions from mobile combustion.
>
> **Information you will need:**
>
> You will need information about the types of vehicles your organization operates, where they are registered, fuel consumption, and miles traveled for each type of vehicle. Fuel consumption data may be obtained from bulk fuel purchases, fuel receipts or direct measurements of fuel use, such as official logs of vehicle fuel gauges or storage tanks. Sources of annual mileage data could include: odometer readings, trip manifests that include mileage to destinations, hours of operation or maintenance records.
>
> **Cross-References:**
>
> Be sure to complete Chapter 11 to determine any fugitive emissions you may have from motor vehicle air conditioning units, if applicable. Review Chapter 1 on geographic boundaries in considering which vehicles are based in California and which are not.

Mobile combustion sources are non-stationary emitters of GHGs such as automobiles, motorcycles, trucks, off-road vehicles such as forklifts and construction equipment, boats, and airplanes. On-road mobile sources include vehicles authorized by the California Department of Motor Vehicles to operate on public roads. Non-road mobile sources include, among other things, trains, ocean-going vessels, and commercial airplanes. Combustion devices that can be transported from one location to another (e.g., small diesel generators) are not considered mobile combustion sources. Reporters should refer to Section III.8 to calculate emissions from such equipment.

Emissions from mobile sources must be included in your emissions report, and can be calculated based on fuel use and/or vehicle miles traveled.

Carbon dioxide emissions, the primary GHG emissions from mobile sources, are directly related to the quantity of fuel consumed. Thus, emission factors are expressed in fuel quantity. On the other hand, combustion emissions of methane and nitrous oxide, while also related to fuel consumption, depend more on the emission control technologies employed in the vehicle. For this reason, their emission factors are typically expressed in terms of mass of compound emitted per distance traveled (gram/mile), and the method of calculating these emissions is based on mileage.

If you have your vehicles' annual fuel consumption information, you are ready to begin your CO_2 emissions calculations. If you have only information on your vehicle miles traveled, you will need to convert that data to fuel consumption based on U.S. EPA's mileage per gallon (mpg) estimates for your vehicles.[1]

The U.S. EPA provides estimates of on-road fuel consumption for passenger cars and light trucks. The California ARB also provides data on composite groups of passenger cars, heavy trucks, and motorcycles. For all other mobile sources, you will need to determine fuel consumption based either on your operating data or published information that is applicable to your vehicle application. EPA fuel economy figures are available at www.fueleconomy.gov/feg/. This website provides two figures for your calculation: one for city driving and one for highway driving.

III.7.1 Calculating Carbon Dioxide Emissions from Mobile Combustion

The method for estimating carbon dioxide emissions from mobile sources includes three steps:

1. Identify total annual fuel consumption by fuel type;
2. Select the appropriate CO_2 emission factor from Appendix C, Table C.3; and
3. Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert kilograms to metric tons.

If you have fuel consumption information, CARROT can calculate your CO_2 emissions for you.

Step 1: Identify total annual fuel consumption by fuel type.

If you are a fleet operator and store fuel at any of your facilities, you can also determine your annual fuel consumption from bulk fuel purchase records.

1 The guidance for calculating methane and nitrous oxide emissions from mobile combustion relies on equipment make, model, and miles driven.

Use Equation III.7a to help you determine your annual fuel consumption. The total annual fuel purchases should include both fuel purchased for the bulk fueling facility and fuel purchased for the vehicles at other fueling locations.

Equation III.7a	Total Annual Fuel Consumption from Bulk Fuel Records					
Total Annual Consumption	=	Total Annual Fuel Purchases	+	Amount Stored at Beginning of the Year	–	Amount Stored at End of Year

Besides bulk storage fuel purchases, additional sources of fuel consumption data may be obtained from collected fuel receipts (for non-bulk purchases) or direct measurements of fuel use, such as official logs of vehicle fuel gauges or storage tanks.

If you only have annual mileage information for the vehicles you own and operate, you may estimate your fuel consumption by using the following procedure or applying a default fuel economy factor.

1. Identify the vehicle make, model, fuel, and model years for all the vehicles you own and operate;
2. Identify the annual mileage by vehicle type; and
3. Convert annual mileage to fuel consumption using EPA's fuel economy formula (Equation III.7b).

If you have very accurate information about the driving patterns of your fleet, consider applying a more specific mix of city and highway driving, otherwise you may assume, as EPA does, that 45% of your vehicles' mileage is highway driving and 55% is city driving (see Equation III.7b). If you utilize more than one type of vehicle in your operations, you must calculate the fuel use for each of your vehicle types and sum them together.

Sources of annual mileage data could include odometer readings or trip manifests that include mileage to destinations. Vehicle mileage may be converted to fuel consumption using the EPA fuel economy of the specific vehicle models in the fleet (www.fueleconomy.gov). Carbon dioxide emissions are then calculated based on the fuel consumption.

For heavy-duty trucks for which no fuel efficiency information is available, you should assume fuel efficiency of 6 mpg for gasoline-powered trucks and 7 mpg for diesel-powered trucks.[2]

Equation III.7b	Fuel Use in Motor Vehicles from Mileage Records											
Total Fuel Use (gallons)	=	Total Mileage (miles)	÷	(	Fuel Economy City (mpg)	x	55%	+	Fuel Economy Highway (mpg)	x	45%	)

Step 2: Select the appropriate carbon dioxide emission factor for each fuel from Appendix C, Table C.3 to calculate carbon dioxide emissions.

Appendix C, Table C.3 provides carbon dioxide emission factors for fuel combusted in motor vehicles and other forms of transport.

Step 3: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2 (see Equation III.7c) and convert kilograms to metric tons.

Equation III.7c	Total CO_2 Emissions from Mobile Combustion					
Total Emissions (metric tons)	=	Fuel Consumed (gallons)	x	Emission Factor (kg CO_2/gallon)	x	0.001 metric tons/kg

III.7.2 Calculating Methane and Nitrous Oxide Emissions for Mobile Combustion

The method for estimating emissions of methane and nitrous oxide from mobile sources involves six steps:

1. Identify the vehicle types, fuel, and model years of all the vehicles you own and operate;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle and fuel type (using Appendix C, Tables C.4 - C.6);
4. Calculate each vehicle type CH_4 and N_2O emissions and convert grams to metric tons;
5. Sum the emissions over each vehicle and fuel type; and
6. Convert CH_4 and N_2O Emissions to CO_2e and sum the subtotals.

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle types and fuel by model year are shown in Appendix C, Table C.4 for passenger cars, light trucks, and heavy-duty vehicles. The emission factors vary with model year because of changes in emission controls and catalysts. Emission factors for alternative fuel vehicles and non-highway vehicles, such as ships and aircraft, are shown in Appendix C, Tables C.5 and C.6.

2 U.S. Department of Energy, Transportation Energy DATA book edition 20 - 2000, Table 8.1.

Step 2: Identify the annual mileage by vehicle type.

If you do not have mileage but you do have fuel consumption by vehicle type model and year you can estimate the vehicle miles traveled using the EPA fuel economy of the specific vehicle models in the fleet. You can then calculate methane and nitrous oxide emissions based on vehicle miles traveled. If you have only bulk fuel purchase data, you should allocate consumption across vehicle types and model years in proportion to the fuel consumption distribution among vehicle type and model years, based on your usage data.

EPA fuel economy figures are available at www.fueleconomy.gov/feg/. Two figures are provided: one for city driving and one for highway driving. You may assume, as EPA does, that 45% of your vehicles' mileage is highway driving and 55% is city driving unless you have specific information to indicate otherwise (see Equation III.7d).

Equation III.7d	Vehicle Mileage from Fuel Use Records
Total Mileage (mi.)	= Fuel use (gallons) x (Fuel Economy City (mpg) x 55% + Fuel Economy Highway (mpg) x 45%)

Step 3: Select the appropriate emission factor for each vehicle and fuel type from Appendix C, Tables C.4, C.5, and C.6.

Step 4: Calculate each vehicle type CH_4 and N_2O emissions and convert to metric tons.

Use Equation III.7e to calculate total emissions for CH_4 and N_2O for each vehicle type.

Equation III.7e	Total CH_4 or N_2O Emissions from Mobile Combustion
Total Emissions (metric tons)	= Emission Factor by Vehicle and Fuel Type (g/mi) x Annual Mileage x 0.000001 metric tons/g

Step 5: Sum the emissions for each vehicle and fuel type.

Add emissions for each vehicle and fuel combination to obtain the total emissions from all mobile sources.

Step 6: Convert CH_4 and N_2O Emissions to CO_2e and sum the subtotals.

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

Emissions from Alternative Fuel Vehicles:

Emissions from Alternative Fuel Vehicles (AFV) are calculated in the same manner as other gasoline or diesel mobile sources, except for electric vehicles. For instance, participants with compressed natural gas or propane fueled vehicles must, as in Section III.7.1, determine the total amount of fuel consumed and apply the appropriate emission factor to calculate emissions. Emission factors for AFVs are included in Appendix C, Table C.5.

Electric vehicles are powered by internal batteries that receive a charge from the electricity grid. Therefore, using electric vehicles produces indirect emissions from purchased electricity.

III.7.3 Calculating Emissions from Off-Road Vehicles/ Construction Equipment

To calculate CO_2 emissions from off-road vehicles/ construction equipment, you should use fuel consumption data and the calculation methodology provided in Section III.7.1 for on-road vehicles.

To calculate the emissions of non-CO_2 gases (e.g., CH_4 and N_2O) from off-road vehicles/construction equipment, you should use fuel consumption data and the off-road vehicle/ construction equipment emission factors in Appendix C, Table C.6. These fuel use-based emission factors are more appropriate than the distance-based emission factors used to calculate emissions of non-CO_2 gases from other mobile sources because off-road vehicles/construction equipment do not have the emission control technologies required of on-road vehicles and, in many instances, do not record miles traveled.

If any off-road equipment has been permitted by a local air regulatory authority as a stationary source, its emissions should be included as stationary combustion, not mobile combustion.

III.7.4 Calculating Carbon Dioxide Emissions from Biofuels

The emissions from vehicles that use biofuels need to be calculated differently than vehicles that use petroleum-based fuels. Biofuels are fuels that are derived from vegetable oil or animal fats that can be added to petroleum -based gasoline or diesel as a blend or used on their own. Since biofuels are derived from a non-petroleum source, the CO_2 emissions that result from their combustion are considered to be biogenic emissions. International consensus on the net climate impact from the combustion of biofuels has not yet been reached. Due to the distinction between biogenic and anthropogenic emissions, the emissions associated with the biofuel portions of biodiesel and ethanol should not be included as a direct mobile emission in your inventory. However, you may choose to report these emissions optionally.

Please note that CH_4 and N_2O emissions from the combustion of biofuels are considered anthropogenic and should be calculated and reported as part of your emissions inventory. CH_4 and N_2O emission factors for biofuels can be found in Appendix C, Table C.5.

Biodiesel is available in both its pure form (100% biodiesel, also known as B100) and in blends with petroleum diesel. Ethanol is generally found as E85, where the fuel is composed of 85% ethanol and 15% gasoline. If your organization is using a blended fuel, you need to include emissions from the petroleum portion of the fuel in the direct mobile emissions section of your inventory. Follow the steps below to calculate the anthropogenic and biogenic CO_2 emissions from a biofuel blend.

Step 1: Identify the biofuel blend being used.

The most popular biodiesel blends are B5 (5% biodiesel), B20 (20% biodiesel) and B100, but any blend between B1 to B100 is possible. Ethanol is most commonly found as E85, but can also occur in a pure form (E100) and in other blends such as E5, E10, E25, etc.

Step 2: Identify total annual biofuel consumption.

Calculate consumption from fuel purchase receipts and/or from vehicle miles traveled. If you are a fleet operator and store fuel at any of your facilities, you can also determine your annual fuel consumption from bulk fuel purchase records.

Step 3: Based on the blend, calculate the annual consumption of petroleum-based fuel and biofuel.

For example, if you are using B20, your annual consumption would have to be split into 20% biodiesel and 80% diesel fuel. For this calculation, see Example III.7.6.

Step 4: Select the appropriate emission factor to calculate the anthropogenic CO_2 emissions.

Appendix C, Table C.3 provides CO_2 emission factors for fuel combusted in motor vehicles and other forms of transport. The CO_2 emission factor for diesel is 10.15 kg per gallon and is 8.81 kg per gallon of gasoline.

Step 5: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Multiply your petroleum-based fuel use from Step 3 by the CO_2 emission factor from Step 4 (See Equation III.7c) and convert kilograms to metric tons.

To calculate the CH_4 and N_2O emissions from ethanol and biodiesel, follow the guidance given in Section III.7.2 and use the emission factors as specified in Appendix C.

Optional Reporting of Biogenic Emissions

If you want to report the biogenic CO_2 mobile emissions from your biofuel use in the optional section of your report, use the same methodology in Steps 4 and 5 above, but use the biofuel CO_2 emission factors for the biofuel portions of your annual fuel use. See Example III.7.6 for how biogenic CO_2 emissions would be calculated for a biodiesel blend. Ethanol-attributed CO_2 emissions would be calculated in the same fashion.

III.7.5 Example: Direct Emissions from Mobile Combustion

GOFAST Vehicle Rental Agency

GOFAST Vehicle Rental is an independent vehicle renting company with a fleet of 200 model year 2000 passenger cars, 25 model year 2000 light duty trucks, and two model year 1998 heavy duty diesel powered trucks. GOFAST typically purchases its fuel in bulk. Last year, the company purchased 235,000 gallons of motor gasoline and 5,000 gallons of diesel fuel. GOFAST began the year with 20,000 gallons of motor gasoline in stock and ended with 10,000 gallons of motor gasoline in stock. The company also began the year with 500 gallons of diesel fuel in stock and ended with 1,000 gallons of diesel fuel in stock.

Carbon Dioxide Emissions Calculation

Step 1: Identify the total annual fuel consumption by fuel type.

Equation III.7a	Total Annual Fuel Consumption by Fuel Type							
Total Fuel Consumption	=	Total Annual Fuel Purchases	+	Amount Stored at Beginning of the Year	-	Amount Stored at End of Year		
Total Gasoline Consumption	=	235,000 gallons	+	20,000 gallons	-	10,000 gallons	=	245,000 gallons
Total Diesel Consumption	=	5,000 gallons	+	500 gallons	-	1,000 gallons		4,500 gallons

Step 2: Select the appropriate carbon dioxide emission factor for each fuel from Appendix C, Table C.3 to calculate carbon dioxide emissions.

The CO_2 emission factor for motor gasoline is 8.81 kilograms per gallon and for diesel fuel it is 10.15 kilograms per gallon.

Carbon Dioxide Emission Factors for Transport Fuels

Carbon Dioxide Emission Factor		
Fuel	**kg CO_2/ MMBtu**	**kg CO_2/gal**
Gasoline	NA	8.81
Diesel Fuel	NA	10.15

Step 3: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions.

Equation III.7c	Carbon Dioxide Emissions Contribution of Each Fuel							
CO_2 from Motor Gasoline	=	8.81 kg/gallon	x	245,000 gallons	x	0.001 metric tons/kg	=	2,158.45 metric tons CO_2
CO_2 from Diesel Fuel	=	10.15 kg/gallon	x	4,500 gallons	x	0.001 metric tons/kg	=	45.68 metric tons CO_2
						Total	=	2,204.13 metric tons CO_2

Methane and Nitrous Oxide Emissions Calculation

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle Type, Fuel, and Model Year

Vehicle Type	Fuel	Model Year
Passenger Cars	Motor Gasoline	1998 through 2002
Light Duty Trucks	Motor Gasoline	1998 through 2002
Heavy Duty Trucks	Diesel	1998

Step 2: Identify the annual mileage by vehicle type

First, GOFAST will have to allocate gross fuel consumption (gallons consumed per year) by vehicle type and model year. For the purposes of this example, it is assumed that GOFAST is able to calculate total fuel consumption based on fuel purchase receipts to arrive at total gallons of fuel consumed for each vehicle type

Then GOFAST must determine vehicle miles traveled using EPA mpg estimates, using Equation III.7d.

Gross Fuel Consumption by Vehicle Type

Vehicle Type	Fuel	Model Year	Fuel Consumption
Passenger Cars	Motor Gasoline	2000	225,000 gallons
Light Duty Trucks	Motor Gasoline	2000	20,000 gallons
Heavy Duty Trucks	Diesel	1998	4,500 gallons

Equation III.7b	Annual Vehicle Miles Traveled												
Total Mileage (mi.)	=	Fuel use (gallons)	x	(	Fuel Economy City (mpg)	x	55%	+	Fuel Economy Highway (mpg)	x	45%	)	
Total Mileage –passenger (mi.)	=	225,000 gallons	x	(	20 mpg	x	55%	+	25 mpg	x	45%	)	= 5,006,250 miles
Total Mileage – light duty (mi.)	=	20,000 gallons	x	(	15 mpg	x	55%	+	20 mpg	x	45%	)	= 345,000 miles
Total Mileage – heavy duty (mi.)	=	4,500 gallons	x	(	8 mpg	x	55%	+	10 mpg	x	45%	)	= 40,050 miles

Step 3: Select the appropriate emission factor from Appendix C, Table C.4 for each vehicle and fuel type.

Emission Factors for Each Fuel and Vehicle Type

Vehicle Type	Fuel	Model Year	Methane (g/mi)	Nitrous Oxide (g/mi)
Passenger Cars	Motor Gasoline	2000	0.0178	0.0273
Light Duty Trucks	Motor Gasoline	2000	0.0346	0.0621
Heavy Duty Trucks	Diesel	1998	0.0051	0.0048

Step 4: Calculate each vehicle type CH_4 and N_2O emissions and convert to metric tons.

Equation III.7e	Passenger Cars: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0178 g/mi	x	5,006,250 (mi)	x	0.000001 metric tons/g	=	0.0891 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0273 g/mi	x	5,006,250 (mi)	x	0.000001 metric tons/g	=	0.1367 metric tons N_2O

Equation III.7e	Light Duty Trucks: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0346 g/mi	x	345,000 (mi)	x	0.000001 metric tons/g	=	0.0119 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0621 g/mi	x	345,000 (mi)	x	0.000001 metric tons/g	=	0.0214 metric tons N_2O

Equation III.7e	Heavy Duty Trucks: Total CH_4 and N_2O Emissions							
CH_4 Emissions (metric tons)	=	0.0051 g/mi	x	40,050 (mi)	x	0.000001 metric tons/g	=	0.0002 metric tons CH_4
N_2O Emissions (metric tons)	=	0.0048 g/mi	x	40,050 (mi)	x	0.000001 metric tons/g	=	0.0002 metric tons N_2O

Step 5: Sum the methane and nitrous oxide emissions for each vehicle and fuel type.

Total Emissions from Mobile Combustion

Vehicle Type	Fuel	Model Year	CH_4 (metric tons)	N_2O (metric tons)
Passenger Cars	Motor Gasoline	2000	0.0891	0.1367
Light Duty Trucks	Motor Gasoline	2000	0.0119	0.0214
Heavy Duty Trucks	Diesel	1998	0.0002	0.0002
		Total	0.1012	0.1583

Step 6: Convert CH_4 and N_2O emissions to CO_2e and sum the subtotals using the GWPs in Appendix C, Table C.1.

Equation III.6c	Convert to Carbon Dioxide Equivalent					
	=	Total Emissions (metric tons)	x	GWP factor		
Total CO_2e (metric tons)	=	0.1012 metric tons CH_4	x	21 (GWP)	=	2.13 metric tons CO_2e
	=	0.1583 metric tons N_2O	x	310 (GWP)	=	49.07 metric tons CO_2e

Total CO_2e Emissions from Mobile Combustion

GHG	metric tons CO_2e
CO_2	2,204.13
CH_4	2.13
N_2O	49.07
Total	2,255.33 metric tons CO_2e

III.7.6 Example: Carbon Dioxide Emissions from Biodiesel

BioClean Drycleaning Service

BioClean is an environmentally-friendly dry cleaning service with a delivery fleet of 10 biodiesel vans. Last year, the company purchased 12,000 gallons of B20 to fuel their vans.

Step 1: Identify the biodiesel blend being used.

BioClean is using B20, which is made up of 20% biodiesel and 80% petroleum-based diesel.

Step 2: Identify total annual biodiesel consumption.

BioClean purchased 12,000 gallons of B20 – they do not store fuel on-site, so no additional mass balance calculation is needed.

Step 3: Based on the blend, calculate the annual consumption of diesel and biodiesel.

Annual consumption of B20 = 12,000 gallons

12,000 gallons x 80% = 9,600 gallons diesel consumed

12,000 gallons x 20% = 2,400 gallons biodiesel consumed

Step 4: Select the appropriate emission factor for the petroleum-based diesel from Appendix C, Table C.3 to calculate the anthropogenic CO_2 emissions.

The CO_2 emission factor for diesel is 10.15 kilograms per gallon, and the biogenic CO_2 emission factor for biodiesel is 9.46 kilograms per gallon.

Carbon Dioxide Emission Factors for Transport Fuels

Fuel	kg CO_2/gallon
Diesel	10.15
Biodiesel (B100)	9.46*

* Note that the CO_2 emissions from burning biodiesel are biogenic, and should not be included as direct mobile emissions in your inventory. These emissions may be reported optionally.

Step 5: Multiply fuel consumed by the emission factor to calculate total CO_2 emissions and convert to metric tons.

Equation III.7c	CO_2 Emissions Contribution of Each Fuel							
CO_2 from diesel	=	10.15 kg/ gallon	x	9,600 gallons	x	0.001 metric tons/kg	=	97.44 metric tons CO_2
Biogenic CO_2 from biodiesel	=	9.46 kg/ gallon	x	2,400 gallons	x	0.001 metric tons/kg	=	22.70 metric tons biogenic CO_2

Chapter 8 Direct Emissions from Stationary Combustion

Who should read Chapter 8:

Chapter 8 applies to participants who generate energy on-site.

What you will find in Chapter 8:

This chapter provides guidance on determining direct emissions from stationary combustion from activities like power generation, manufacturing or other industrial activities involving the combustion of fossil fuels.

Information you will need:

You will need information about the type of fuels consumed by your organization and how much was combusted in the reporting year, or CEMS data.

Cross-References:

If your organization imports steam or district heating and cooling, you will utilize the calculation guidelines in Chapter 9 to assist you in calculating these indirect emissions.

Stationary combustion sources are non-mobile sources emitting GHGs from fuel combustion. Typical large stationary sources include power plants, refineries, and manufacturing facilities. Smaller stationary sources include commercial and residential furnaces.

If you combust fuels to produce electricity for your own use or make steam or district heating and cooling for your own use or to sell, then it should also follow the GHG emissions accounting and reporting guidelines in this chapter. However, if you combust fossil fuels to produce electricity and sell the power to other parties (an electric power generator) then you should use the California Registry's Power/Utility Protocol.

III.8.1 Emission Factors for Stationary Combustion

Default emission factors are provided in Appendix C, Tables C.7, C.8, and C.9. If your company has verifiable emission factors that are more accurate for the fuels and combustion devices that your organization employs, you may use these factors. If you decide not to use the California Registry-approved emission factors, you will need to demonstrate to your verifier that the use of the alternative emission factors results in a more accurate measurement of your emissions.

The following is a list of sources where you can obtain additional emission factors:

- U.S. EPA, Compilation of Air Pollutant Emission Factors AP-42, www.epa.gov/ttn/chief/ap42;
- U.S. EPA Emissions Inventory Improvement Program (EIIP) Introduction to Estimating Greenhouse Gas Emissions: Volume VII (EIIP, 1999), www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html;
- 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Greenhouse Gas Inventories Reference Manual (IPCC, 2006), www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm; and
- UK Department for Environment, Food, and Rural Affairs, Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme (DEFRA, 2004), www.defra.gov.uk/environment/climatechange/trading/uk/documents.htm.

III.8.2 Estimating Emissions Based on Higher Heating Value

To estimate stationary combustion emissions, the Protocol utilizes GHG emission factors that are based on the "higher" heating value (HHV) (or "gross" heating value (GHV)) for combusted fossil fuels. When hydrocarbons are combusted, heat, water vapor, and CO_2 are emitted, along with trace levels of other GHGs like CH_4 and N_2O. In the United States, a HHV is used to measure the heat content of fuels and is therefore used to estimate GHG emissions from the combustion process. This approach is used by the U.S. Energy Information Administration (EIA). However, it should be noted that the "lower" heating value (LHV) is typically used internationally.[1]

III.8.3 Using Continuous Emissions Monitoring System Data

Typically, participants calculate GHG emissions from stationary combustion using the process outlined in the subsequent section. However, if you use a Continuous Emissions Monitoring System (CEMS) to measure emissions, you may also report your stationary combustion emissions from your CEMS reports.

1 Converting from HHVs to LHVs is an imperfect process. Emissions estimates based on LHVs are between 5% to 10% higher because the Btu content of the fuel is around 5% to 10% lower. See OECD, Estimation of Greenhouse Gas Emissions and Sinks, Final Report (Paris, France, August 1991), pp. 2-12 – 2-15.

Participants using CEMS should refer to the California Registry's Power/Utility Protocol for guidance on reporting emissions from combustion devices equipped with CEMS units.

Stationary Emissions from Agriculture Residue Burning:

This Protocol does not include specific guidance on estimating emissions from agricultural residue burning. Useful information is provided in the CEC's Guidance to the California Climate Action Registry: General Reporting Protocol, P500-02-005F (June 2002).

III.8.4 Calculating Emissions from Stationary Combustion

Emissions estimation for stationary combustion involves the following process:

1. Identify all types of fuel directly combusted in your operations;
2. Identify annual consumption of each fuel;
3. Select the appropriate adjusted emission factor for each fuel;
4. Calculate each fuel's CO_2 emissions and convert to metric tons;
5. Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons; and
6. Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

CARROT can also calculate this information for you, and will prompt you to enter your fuel type and inputs.

Step 1: Identify all types of fuel directly combusted in your operations.

Fuel types can include, for example, coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Step 2: Determine annual consumption of each fuel.

This can be done by direct measurement, recording fuel purchase, or sales invoices measuring any stock change (measured in million Btu, gallons or therms) using Equation III.8a.

Equation III.8a	Annual Consumption of Fuels							
Annual Consumption (MMBtu or gallons)	=	Total Annual Fuel Purchases	-	Total Annual Fuel Sales	+	Amount Stored at Beginning of Year	-	Amount Stored at Year End

If your fuel consumption is not available in million Btu, gallons or therms, you can convert it using the conversion factors in Table III.8.1.

Table III.8.1 Conversion Factors for Stationary Combustion Calculations

Unit	Multiplied by	Equals
Barrels	42.0	1 Gallon
Therms of Natural Gas	0.1	Million Btu
Thousand Cubic Feet of Natural Gas	1.03	Million Btu
Metric Tons of Coal, Electric Utility	22.488	Million Btu
Metric Tons of Coal, Industrial Coke	30.232	Million Btu
Metric Tons of Coal, Other Industry	24.790	Million Btu
Metric Tons of Coal, Residential & Commercial	26.323	Million Btu

Source: Energy Information Administration, Annual Energy Review 2000 (2002).

Step 3: Select the appropriate emission factor for each fuel.

Each fuel type has a specific emission factor that relates to the amount of CO_2, CH_4 or N_2O emitted per unit of fuel consumed (either in kilograms per MMBtu of fuel or kilograms per gallon of fuel). CO_2 emission factors depend almost completely on the carbon content of the fuel. CH_4 and N_2O emission factors also depend on the type of combustion device and the combustion conditions.

Carbon Dioxide. Appendix C, Table C.7 provides CO_2 emission factors for the most common fuel types in kilograms of CO_2 per million Btu (MMBtu) and in kilograms of CO_2 per gallon for liquid fuels. If you burn a fuel that is not listed in Appendix C, Table C.7, you should estimate an emission factor based on the specific properties of the fuel and document those properties.

Methane and Nitrous Oxide. Appendix C, Tables C.8 and C.9 present CH_4 and N_2O emission factors by activity sector and fuel type. For petroleum products, emission factors for CH_4 and N_2O are provided in kilograms per MMBtu and kilograms per gallon consumed.

Step 4: Calculate each fuel's carbon dioxide emissions and convert to metric tons.

If the fuel consumption is expressed in MMBtu, use Equation III.8b. If fuel is expressed in gallons, use Equation III.8c.

Equation III.8b	Total CO_2 Emissions (fuel consumption is in MMBtu)					
Total Emissions (metric tons)	=	Emission Factor (kg CO_2/MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation III.8c	Total CO_2 Emissions (fuel consumption is in gallons)					
Total Emissions (metric tons)	=	Emission Factor (kg CO_2/gallon)	x	Fuel Consumed (gallon)	x	0.001 metric tons/kg

Step 5: If you are reporting methane and nitrous oxide emissions, calculate each fuel's methane and nitrous oxide emissions and convert to metric tons.

If your fuel consumption is expressed in MMBtu, use Equation III.8d. If it is expressed in gallons, use Equation III.8e. Note, non-CO_2 gases may be de minimis.

Equation III.8d	Total CH_4 or N_2O Emissions (fuel consumption is in MMBtu)					
Total Emissions (metric tons)	=	Emission Factor (kg CH_4 or N_2O / MMBtu)	x	Fuel Consumed (MMBtu)	x	0.001 metric tons/kg

Equation III.8e	Total CH_4 or N_2O Emissions (fuel consumption is in gallons)					
Total Emissions (metric tons)	=	Emission Factor (kg CH_4 or N_2O / gallon)	x	Fuel Consumed (gallon)	x	0.001 metric tons/kg

Step 6: Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert CH_4 and N_2O to CO_2 equivalent.

III.8.5 Allocating Emissions from Co-Generation

Accounting for the GHG emissions from a co-generation or combined heat and power (CHP) facility is unique because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the fuel and the GHG emissions between the two different energy streams is useful.[2]

Ultimately, to comply with California Registry reporting guidelines, reporters only have to determine absolute emissions from a co-gen plant. This is done in a manner identical with the calculation procedure for non-co-generation plants. That is, to calculate total emissions associated with a co-generation plant participants multiply the fuel input by a fuel specific emission factor. Alternatively participants can allocate emissions according to each final product stream (i.e., electricity or steam). The three most commonly-used methods to allocate emissions of CHP plants between the electric and thermal outputs are:

1. **Efficiency method**: On the basis of the energy input used to produce the separate steam and electricity products.
2. **Energy content method**: On the basis of the energy content of the output steam and electricity products.
3. **Work potential method**: On the basis of the energy content of the steam and electricity products.

Considerations in Selecting an Approach to CHP Emissions Allocation

Efficiency Method

- Allocates emissions according to the amount of fuel energy used to produce each final energy stream.
- Assumes that conversion of fuel energy to steam energy is more efficient than converting fuel to electricity. Thus, focuses on the initial fuel-to-steam conversion process.
- Actual efficiencies of heat and of power production will not be fully characterized, necessitating the use of assumed values.

Energy Content Method

- Allocates emissions according to the useful energy contained in each CHP output stream.
- Need information regarding the intended use of the heat energy.
- Best suited where heat can be characterized as useful energy (e.g., for process or district heating).
- May not be appropriate where heat is used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emissions factor associated with the heat stream.

Work Potential Method

- Allocates emissions based on the useful energy represented by electric power and heat, and defines

2 Many CHP systems capture the waste-heat from the primary electricity generating pathway and use it for non-electricity purposes. When the waste-heat is used directly to drive a thermal generator or to make steam that in turn drives an electric generator, these combined electricity production processes are grouped as a unit and called a combined cycle power plant. (The California Registry treats emissions resulting from combined cycle power plants as stationary combustion emissions.)

useful energy on the ability of heat to perform work.

- Appropriate when heat is to be used for producing mechanical work (where much of the heat energy will not be characterized as useful energy).
- May not be appropriate for systems that sell hot water because hot water cannot be used, as steam can, to perform mechanical work.

In order to ensure a consistent approach in allocating GHG emissions in CHP applications, the California Registry recommends the use of the efficiency method. A default quantification methodology is provided below for this method. For more information on alternative CHP methods, see the GHG Protocol.[3]

Using the Efficiency Method to Allocate Emissions from CHP Facilities

For this method, emissions are allocated based on the separate efficiencies of steam and electricity production. You will need to know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of CO_2 emissions attributable to steam (or heat) and electricity production:

Step 1: Determine the total direct emissions from the CHP system.

Calculate total direct GHG emissions using Equation III.8b or III.8c, above. Like the guidance for non-cogeneration stationary combustion, calculating total emissions from CHP sources is based on fuel input values.

Step 2: Determine the total steam and electricity output for the CHP system.

To determine the total energy output of the CHP plant attributable to steam production, use published steam tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions. Obtain steam energy content values from the IAPWS-IF97 steam tables.[4] Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values; express in units of MMBtu.

Alternatively, use Equation III.9a to determine the total net heat steam (or heat) production.

To convert total electricity production from MWh to MMBtu, multiply by 3.415.[5]

3 GHG Protocol, 2004 .

Step 3: Determine the efficiencies of steam and electricity production.

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80% for steam and a default value of 35% for electricity.[6]

Step 4: Determine the fraction of total emissions to allocate to steam and electricity production.

Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation III.8f.

Where:

E_H = Emissions allocated to steam production
H = Total steam (or heat) output (MMBtu)
e_H = Efficiency of steam (or heat) production
P = Total electricity output (MMBtu)
e_P = Efficiency of electricity generation
E_T = Total direct emissions of the CHP system
E_P = Emissions allocated to electricity production

Equation III.8f **Steam and Electricity Emissions Allocation**

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} \times E_T$$

$$\text{and} \quad E_P = E_T - E_H$$

4 IAPWS Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam (IAPWS-IF97), International Association for the Properties of Water and Steam. This publication replaces IFC-67.

5 MWh to MMBtu conversion source – EIA, Annual Energy Review 1995, DOE/EIA-0384(95) (Washington, DC, July 1996), Appendix B.

6 The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. If the constraints are not satisfied the efficiencies of the steam and electricity can be modified until constraints are met.

III.8.6 Example: Direct Emissions from Stationary Combustion

F&M Manufacturing

F&M is a manufacturing facility located in California. It has two 10 MW generating units, one burning natural gas and one coal-fired unit. F&M also has a commercial office building in California that is heated with diesel.

Step 1: Identify all types of fuel directly combusted in your operations.

Fuel Type, Sector, and Location

Fuel	Sector
Natural Gas	Manufacturing
Coal	Manufacturing
Diesel	Commercial

Step 2: Determine annual consumption of each fuel.

F&M measures heat input (MMBtu of fuel used) into its plants, and purchases its heating fuel for commercial use in bulk by the barrel. Last year it consumed 788,400 MMBtu of natural gas and 946,000 MMBtu of coal. It also purchased 265 barrels of distillate fuel for heating and sold 15 barrels. F&M began the year with 12 barrels in storage and ended the year with 24 barrels in storage. Using Equation III.8a, F&M determined distillate fuel consumption. The result, 238 barrels can be converted to gallons by multiplying by 42. See Table III.8.1.

Equation III.8a	Annual Consumption of Fuels										
Annual Consumption (MMBtu or gallons)	=	Total Annual Fuel Purchases	-	Total Annual Fuel Sales	+	Amount Stored at Beginning of Year	-	Amount Stored at Year End		
Annual Consumption of Distillate Fuel	=	265 barrels	-	15 barrels	+	12 barrels	-	24 barrels	=	238 barrels consumed
						238 barrels consumed	x	42 gallons/ barrel	=	9,996 gallons

Step 3: Select the appropriate emission factors for each fuel from Appendix C, Tables C.7, C.8 and C.9.

Emission Factors by Fuel Type and Sector

		kg CO_2 per		kg CH_4 per		kg N_2O per	
Fuel	**Sector**	**MMBtu**	**Gallon**	**MMBtu**	**Gallon**	**MMBtu**	**Gallon**
Natural Gas	Manufacturing	53.06	–	0.0010	–	0.0001	–
Coal	Manufacturing	93.98	–	0.0110	–	0.0016	–
Distillate Fuel/Diesel	Commercial	73.15	10.15	0.0110	0.0015	0.0006	0.0001

Step 4: Calculate each fuel's carbon dioxide emissions.

Use Equation III.8b if the fuel consumption is expressed in MMBtu, and Equation III.8c if it is expressed in gallons.

Equation III.8b	Carbon Dioxide Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	53.06 kg CO_2/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	41,832.5 metric tons CO_2

Equation III.8b	Carbon Dioxide Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	93.98 kg CO_2/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	88,905.08 metric tons CO_2

Equation III.8c	Carbon Dioxide Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	10.15 kg CO_2/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	101.46 metric tons CO_2

Total CO_2 from All Sources	=	130,839.04 metric tons CO_2

Step 5: Calculate each fuel's methane and nitrous oxide emissions.

Use Equation III.8d if the fuel consumption is expressed in MMBtu, and Equation III.8e if it is expressed in gallons. Note, both methane and nitrous oxide emissions from stationary combustion are likely to be de minimis.

Equation III.8d	Methane Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	0.0010 kg CH_4/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	0.788 metric tons CH_4

Equation III.8d	Methane Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	0.0110 kg CH_4/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	10.406 metric tons CH_4

Equation III.8e	Methane Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	0.0015 kg CH_4/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	0.015 metric tons CH_4

Total CH_4 from All Sources	=	11.21 metric tons CH_4

Equation III.8d	Nitrous Oxide Emissions from Natural Gas (MMBtu)							
Total Emissions (metric tons)	=	0.0001 kg N_2O/ MMBtu	x	788,400 MMBtu	x	0.001 metric tons/ kg	=	0.0788 metric tons N_2O

Equation III.8d	Nitrous Oxide Emissions from Coal (MMBtu)							
Total Emissions (metric tons)	=	0.0016 kg N_2O/ MMBtu	x	946,000 MMBtu	x	0.001 metric tons/ kg	=	1.514 metric tons N_2O

Equation III.8e	Nitrous Oxide Emissions from Distillate Fuel (Gallons)							
Total Emissions (metric tons)	=	0.0001 kg N_2O/ gallon	x	9,996 gallons	x	0.001 metric tons/ kg	=	0.0010 metric tons N_2O

Total N_2O from All Sources	=	1.594 metric tons N_2O

Step 6: Convert CH_4 and N_2O emissions to CO_2e and sum the subtotals.

Use the IPCC GWP factors (SAR) from Table C.1, Appendix C to convert CH_4 and N_2O to CO_2 equivalent.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent					
Metric Tons of CO_2e	=	Metric Tons of GHG	x	GWP (SAR, 1996)	=	130,839.04 metric tons CO_2e
CH_4 Tons of CO_2e	=	11.21 metric tons CH_4	x	21 (GWP)	=	235.41 metric tons CO_2e
N_2O Tons of CO_2e	=	1.594 metric tons N_2O	x	310 (GWP)	=	494.2 metric tons CO_2e
				Total	=	131,568.65 metric tons CO_2e

Chapter 9 Indirect Emissions from Imported Steam, District Heating and Cooling, and Electricity from a Co-Generation Plant

Who should read Chapter 9:

Chapter 9 applies to organizations that purchase electricity, steam or heating and cooling from a co-generation plant or conventional boiler that they do not own or operate.

What you will find in Chapter 9:

This chapter provides guidance on estimating indirect emissions from co-generation, imported steam, and district heating and cooling. The chapter includes the quantification methodology for co-generation and an example addressing indirect emissions from district heating.

Information you will need:

You will need information about the type of co-generation, imported steam and heat, and imported cooling your organization uses, and the types and amounts of fuel consumed by the plant to generate that electricity, heating or cooling. For example, for heat or electricity from a co-generation facility, you will need information about the plant's net heat production and net electricity production in addition to your organization's own consumption of that power.

This chapter applies to organizations that purchase steam, district heat, cooling or electricity from a co-generation or conventional boiler plant that they do not own or operate. Emissions associated with these sources are considered to be indirect. If you own or operate a co-generation or conventional boiler plant, you should calculate your direct emissions from the combustion of the fossil fuels at the plant as described in Chapter 8.

III.9.1 Calculating Indirect Emissions from Heat and Power Produced at a Co-Generation Facility

Emissions from co-generation facilities—also referred to as combined heat and power (CHP) plants—represent a special case for estimating indirect emissions. Because co-generation simultaneously produces electricity and heat (or steam), attributing total GHG emissions to each product stream would result in double counting. Thus, when two or more different parties receive the energy streams from co-generation plants, GHG emissions must be determined and allocated separately for heat production and electricity production. Since the output from co-generation results simultaneously in heat and electricity, you can determine what "share" of the total emissions is a result of electricity and heat by using a ratio based on the Btu content of heat and/or electricity relative to the co-generation plant's total output.

The process for estimating indirect emissions from heat and power produced at a co-generation facility involves the following five steps:

1. Obtain total emissions and power and heat generation information from co-generation facility;
2. Determine emissions attributable to net heat production and electricity production;
3. Calculate emissions attributable to your portion of heat and electricity consumed;
4. Convert any non-CO_2 emissions to carbon dioxide equivalent, as applicable; and
5. Sum CO_2e.

Step 1: Obtain emissions and power and heat information from the co-generation facility.

You will need to obtain the following information from the CHP plant owner or operator to estimate indirect GHG emissions:

1. Total emissions of carbon dioxide (and methane and nitrous oxide when they are being reported) from the co-generation facility - based on fuel input information;
2. Total electricity production from the co-generation plant - based on generation meter readings; and
3. Net heat production from the co-generation plant.

Net heat production refers to the useful heat that is produced in co-generation, minus whatever heat returns to the boiler as steam condensate, as shown in Equation III.9a.[1]

Equation III.9a	Net Heat Production			
Net Heat Production (MMBtu)	=	Heat of Steam Export (MMBtu)	-	Heat of Return Condensate (MMBtu)

Step 2: Determine emissions attributable to net heat production and electricity production for the co-generation plant.

Refer to Section III.8.5 in the Stationary Combustion chapter titled "Allocating Emissions from Co-Generation"

1 Alternatively, refer to p. 45 "Step 2" for guidance on determining net heat production from steam temperature and pressure data.

to calculate emissions attributable to net heat and electricity production.

Step 3: Calculate emissions attributable to your portion of heat and electricity consumed.

Once you have determined total emissions attributable to heat (or steam) and electricity production, you will need to determine your portion of heat or electricity consumed, and thus your indirect GHG emissions associated with heat or electricity use. First, obtain your electricity and heat (or steam) consumption information, then use Equations III.9b and III.9c to calculate your share of emissions, as appropriate.

Equation III.9b	**Indirect Emissions Attributable to Electricity Consumption**					
Indirect Emissions Attributable to Electricity Consumption	=	CHP Emissions Attributable to Electricity Production (metric tons)	x	(Your Electricity Consumption (kWh)	÷	Total CHP Electricity Production (kWh))

Equation III.9c	**Indirect Emissions Attributable to Heat or Steam Consumption**					
Indirect Emissions Attributable to Heat Consumption (metric tons)	=	CHP Emissions Attributable to Heat Production (metric tons)	x	(Your Heat Consumption (MMBtu)	÷	CHP Net Heat Production (MMBtu))

Step 4: Convert any non-CO_2 emissions to CO_2e, as applicable, and sum subtotals.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

III.9.2 Calculating Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

The following process leads participants through a procedure to calculate emissions from imported steam or district heating produced at a conventional boiler plant that does not generate electricity – i.e., the boiler plant is not a co-generation facility. The method for quantifying indirect emissions from imported steam or district heating largely mirrors that for calculating direct emissions from stationary combustion, with the additional step to incorporate efficiency losses for steam generation and distribution.

In order to calculate fuel consumption at the boiler, you can use the heat contained in the steam or hot water you receive, rather than rely on actual fuel measurements, which may not be available (see Equations III.9d and III.9e). Once you have identified fuel consumption at the boiler, you can calculate total emissions by multiplying total energy by the emission factors provided in Appendix C, Tables C.7, C.8, and C.9. If you know the efficiency factor for generation and transmission of imported steam or hot water, please use it in your calculation. (Note that heat loss during transmission should be reflected in this efficiency factor.)

If the efficiency is unknown, use an efficiency factor of 75%.

Use the following four steps to estimate your total GHG emissions from imported steam or district heating:

1. Determine energy obtained from steam or district heating;
2. Determine energy consumed at the steam or district heating plant;
3. Determine appropriate emission factor for the fuel; and
4. Multiply energy consumed by the emissions factor to derive emission estimates.

Step 1: Determine energy obtained from steam or district heating.

You can use monthly energy bills to determine the energy obtained from steam or district heating. The monthly bills should be summed together over the year to give annual consumption. You will want to total your data in million Btu (MMBtu).

Heating Bills Expressed in Therms. If your heating bills are expressed in therms, you can convert the values to MMBtu by multiplying by 0.1, as shown in the Equation III.9d.

Equation III.9d	**Steam Energy Consumption (from therms)**			
Energy Consumption (MMBtu)	=	Energy Consumption (therms)	x	0.1 MMBtu/ therm

Heating Bills Expressed in Pounds of Steam. If your steam consumption is billed in pounds (lbs), you either need to monitor the temperature and pressure of the steam you have received, or request it from the steam supplier. Calculate the thermal energy of the steam using saturated water at 212°F as the reference.[2] The thermal energy consumption is calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy (or heat content) of the saturated water at the reference conditions (or heat content). The enthalpy of the

2 American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry (2001).

3 See, for example, J.H. Keenan, Keyes, Hill, et al, Steam Tables (1969) and R.J. Reed, Ed., North American Combustion Handbook, Second Edition (1978), pages 349.

Equation III.9e — **Steam Energy Consumption (from pounds)**

$$\text{Energy Consumption (MMBtu)} = \left(\text{Enthalpy of Delivered Steam (Btu/lb)} - 180\ \text{(Btu/lb)} \times\right) \text{Mass of Steam Consumed (lbs)} \div 1{,}000{,}000\ \text{(Btu/MMBtu)}$$

Equation III.9f — **Energy Input by Steam or District Heating Plant**

$$\text{Energy Consumption (MMBtu)} = \text{Energy Use for Heating (MMBtu)} \div \left[\text{Fractional Boiler Efficiency} \times \left(1 - \text{Fractional Transport Losses}\right)\right]$$

steam can be found in standard steam tables. The enthalpy of saturated water at the reference conditions is 180 Btu per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation III.9e.

Step 2: Determine the energy consumed by the steam or district heating plant.

Once you have estimated your steam consumption, you can estimate the energy consumed at the steam or district heating plant by dividing your energy consumption by the system efficiency. If you can obtain information about the efficiency of the boiler used to produce the steam or hot water and any transport losses that occur in delivering the steam, use Equation III.9f. If transport losses or boiler efficiency vary seasonally, energy input should be calculated on a monthly or seasonal basis, and summed together to arrive at the total annual energy input for Step 4.

Estimated System Efficiency. As shown in Equation III.9g, if you are unable to obtain the system efficiency, divide energy consumption from Step 1 by an estimated total efficiency—boiler efficiency and transport losses combined—of 75%.

Equation III.9g — **Energy Input (plant efficiency unknown)**

$$\text{Energy Input (MMBtu)} = \text{Energy Consumption (MMBtu)} \div 0.75$$

Step 3: Determine appropriate emission factors.

Because emissions will vary with fuel type, you need to know the type of fuel that is burned in the plant supplying your steam or hot water. You can obtain this information from the plant's energy supplier. Once you have the type of fuel being combusted to generate the steam or hot water, use the emission factors for stationary fuel combustion in Appendix C, Tables C.7, C.8, and C.9.

Step 4: Calculate total emissions from imported steam or district heating.

Once you have both the value of total energy consumed from Step 2 and the appropriate emission factor from Step 3, use Equation III.9h to calculate total GHG emissions from imported steam or hot water.

Equation III.9h — **Total Emissions from Steam System**

$$\text{Total Emissions (metric tons)} = \text{Energy Consumed (MMBtu)} \times \text{Emission Factor (kg/MMBtu)} \times 0.001\ \text{metric tons/kg}$$

Step 5: Convert any CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert methane and nitrous oxide to carbon dioxide equivalent.

III.9.3 Calculating Indirect GHG Emissions from District Cooling

When you purchase cooling services using district cooling, the compressor system that produces the cooling is driven by either electricity or fossil fuel combustion. Your indirect emissions from district cooling represent your share of the total cooling demand from the cooling plant, multiplied by the total GHG emissions generated by that plant. You can begin the process of estimating your indirect emissions from district cooling by summing together the total cooling on your monthly cooling bills.

Once you have determined your total cooling, you can use one of two options—either a simplified or more detailed approach—to estimate your GHG emissions.

Simplified Approach (Option 1). The simplified approach uses an estimated value for the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP). Thus, this approach allows you to estimate the portion of energy used at the district cooling plant directly attributable to your cooling.

Detailed Approach (Option 2). COPs for chillers may vary by more than an order of magnitude, making it necessary to obtain the COP for the cooling plant. The more detailed

approach allows you to determine the total cooling-related emissions from the district cooling plant and your fraction of total load hours.

Simplified Approach Using an Estimated Coefficient of Performance - Option 1

Step 1: Determine your annual cooling demand.

While your cooling bill may be reported in terms of million Btu (MMBtu), it will typically report cooling demand in ton-hours. You can convert ton-hours of cooling demand to MMBtu using Equation III.9i. If you are billed monthly, sum together your cooling demand for every month to yield an annual total.

Equation III.9i	Annual Cooling Demand					
Cooling Demand (MMBtu)	=	Cooling Demand (ton-hours)	x	12,000 (Btus/ton-hour)	x	0.000001 (MMBtu/Btu)

Step 2: Estimate COP for the plant's cooling system.

If you are able to obtain the COP for the cooling plant, proceed to Step 3. However, if you cannot obtain the COP itself, try to determine the type of chiller used by the district cooling plant. With that information, a rough estimate of the COP may be selected from the typical values shown in Table III.9.1.

Table III.9.1 Typical Chiller Coefficients of Performance

Equipment Type	Coefficient of Performance (COP)	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas
Electric-Driven Compressor	4.2	Electricity

Step 3: Determine energy input.

To determine the energy input to the system resulting from your cooling demand, use Equation III.9j.

For an electric driven compressor, convert the energy input in MMBtu into kWh by multiplying by 293.1.

Equation III.9j	Energy Input from Cooling Demand			
Energy Input (MMBtu)	=	Cooling Demand (MMBtu)	÷	COP

Step 4: Calculate total GHG emissions resulting from cooling.

Where Cooling Plant Uses Absorption Chillers or Engine-Driven Compressors. If you can determine what type of fuel is being used, multiply the energy input by the appropriate emission factor in Appendix C, Tables C.7, C.8, and C.9. If the fuel type cannot be determined, assume natural gas and multiply the energy input by the emission factors for natural gas according to Equation III.9k.

Equation III.9k	Total Cooling Emissions - Simplified Approach					
Total Cooling Emissions (metric tons)	=	Energy Input (MMBtu)	x	Emission Factor (kg/MMBtu)	x	0.001 metric tons/kg

Where Cooling Plant Uses Electric-Driven Compressors. If the cooling plant uses an electrically driven compressor, calculate emissions using the procedures described in Chapter 6 on indirect emissions from electricity consumption.

Detailed Approach Based on Cooling Plant Emissions and Your Organization's Share of Total Cooling Demand - Option 2

Step 1: Determine total cooling-related emissions from the district cooling plant.

District cooling plants take a variety of forms and may produce electricity, hot water or steam for sale in addition to cooling.

Where Cooling Plant Produces Only Cooling. In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, you will be able to determine total cooling emissions based on 1) total indirect emissions from cooling plant electricity and heat consumption (metric tons) and 2) total direct emissions from cooling plant fuel combustion (metric tons).

The process for calculating the indirect and direct emissions is described in Sections III.6 and III.8. You will need to obtain the emission values from the district cooling plant or calculate the emissions based on the fuel consumption, as well as electricity and steam consumption information, provided by the plant.

Where Cooling Plant Produces More than Cooling. In many cases, the simple situation described above will not

apply. Instead, the cooling plant will be integrated into a combined heat and power plant, where some of the steam and electricity produced by the plant may be used for cooling, and some may be used for other purposes. In this case, the emissions from the combined heat and power plant will need to be allocated between heating and electricity production (or shaft work in the case of internal combustion engines), and these emissions will have to be scaled by the fraction of the heat or electricity that is used for cooling, as shown in Equation III.9l, which assumes 90% efficiency for boiler emissions and allocates all other waste heat to electrical efficiency.

The attribution of emissions to the heat and power streams is done in the same manner as described above.

Step 2: Determine fraction of cooling emissions attributable to your operations.

The next step in calculating your GHG emissions from cooling is to scale the total plant cooling emissions by the percentage of your share of the cooling load. Equation III.9m demonstrates how the total cooling load on the plant is scaled to determine your cooling emissions.

Step 3: Determine total yearly emissions.

For each month (or longer period) of the year, cooling emissions should be calculated as described in Steps 1 and 2, above. The duration of the periods for which the emissions are calculated will depend on the data available. Ideally, calculations would be made monthly for cooling plants integrated with CHPs, as emissions associated with cooling will depend on how the CHP outputs are distributed. If data for making these calculations are not available on a monthly basis, then longer periods will be used. In either case, the emissions for each period must be summed over the year to obtain the annual total.

Additional guidance on estimating GHG emissions from co-generation electricity and heat can be found through the following:

- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council for Sustainable Development (October 2001). The tool entitled *Calculating CO_2 Emissions from Stationary Sources* addresses emissions from co-generation facilities (www.ghgprotocol.org/standard/tools.htm).
- Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme, prepared by the U.K. Department for Environment, Food and Rural Affairs (August 2001) (www.defra.gov.uk/environment/climatechange/trading).
- EPA Climate Leaders Inventory Protocol, U.S. Environmental Protection Agency (in development as of August 2002). EPA's protocol includes a module focusing on indirect emissions from electricity and/or steam purchases (www.epa.gov/climateleaders/index).

Equation III.9l — Cooling Emissions (from plant with multiple product streams)

$$\begin{aligned}\text{Total Cooling Emissions (metric tons)} = {} & \left[\text{Fraction of CHP Electricity Prod. Used for Cooling} \times \left(\left(\text{Total Fuel Heat Input (MMBtu)} - \text{Net Heat Production (MMBtu)}\right) \div 0.9\right) \div \text{Total Fuel Heat Input (MMBtu)}\right] \\ & + \left[\text{Fraction of CHP Heat Prod. Used for Cooling} \times \left(\text{Net Heat Production (MMBtu)} \div \left(0.9 \times \text{Total Fuel Heat Input (MMBtu)}\right)\right)\right] \times \text{Total CHP Emissions (metric tons)}\end{aligned}$$

Equation III.9m — Annual Cooling Emissions

$$\text{Participant Cooling Emissions (metric tons)} = \text{Total Cooling Emissions (metric tons)} \times \left(\text{Participant Cooling Load (ton-hour)} \div \text{Total Cooling Load (ton-hour)}\right)$$

III.9.4 Example: Indirect Emissions from District Heating

Socal Manufacturing Company

The Socal Manufacturing Company imports steam at its Bakersfield facility. The steam is imported from a conventional natural gas-fired boiler. The boiler efficiency is 85% and the loss factor is 6%.

Step 1: Determine energy obtained from steam or district heating.

Since its energy consumption is provided in therms on its monthly billing, Socal uses Equation III.9d to determine energy consumption. Socal consumed 6,000 therms in the past year.

Equation III.9d	Energy Consumption for Steam					
Steam Energy Consumption (MMBtu)	=	6,000 Therms	x	0.1 MMBtu/ therm	=	600 MMBtu

Step 2: Determine the energy consumed by the steam or district heating plant.

Socal uses its boiler efficiency of 85% and loss factor of 6% to calculate its Energy Input.

Equation III.9f	Energy Input											
Energy Input (MMBtu)	=	600 MMBtu	÷	[	0.85 (boiler efficiency)	x	(	1	-	0.06	)]	= 750.94 MMBtu

Step 3: Determine appropriate emission factors.

Since natural gas is used to generate the steam, use emissions factors in MMBtu from Appendix C, Tables C.7 and C.8

Emission Factors for Natural Gas

Fuel	Gas Emitted	Emission Factor
Natural Gas	Carbon Dioxide	53.06 kg/MMBtu
Natural Gas	Methane	0.0010 kg/ MMBtu
Natural Gas	Nitrous Oxide	0.0001 kg/MMBtu

Step 4: Calculate total emissions.

Steam-related methane and nitrous oxide emissions are likely to be de minimis.

Equation III.9k	Total Emissions							
Total Carbon Dioxide (CO_2) Emissions (kg)	=	750.94 MMBtu	x	53.06 kg/MMBtu	x	0.001 metric tons/ kg	=	39.85 metric tons CO_2
Total Methane (CH_4) Emissions (kg)	=	750.94 MMBtu	x	0.0010 kg/MMBtu	x	0.001 metric tons/ kg	=	0.00075 metric tons CH_4
Total Nitrous Oxide (N_2O) Emissions (kg)		750.94 MMBtu	x	0.0001 kg/MMBtu	x	0.001 metric tons/ kg	=	0.000075 metric tons N_2O

Step 5: Convert CH_4 and N_2O emissions to CO_2e and sum all subtotals.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent				
Metric Tons of CO_2e		Metric Tons of GHG	x	GWP (SAR, 1996)		
Metric Tons of CO_2	=				=	39.85 metric tons CO_2e
CH_4 Metric Tons of CO_2e	=	0.00075 metric tons CH_4	x	21 (GWP)	=	0.0158 metric tons CO_2e
N_2O Metric Tons of CO_2e		0.000075 metric tons N_2O	x	310 (GWP)	=	0.0233 metric tons CO_2e
				Total	=	39.89 metric tons CO_2e

Chapter 10 Direct Emissions from Sector-Specific Processes

Who should read Chapter 10:

Chapter 10 applies to organizations with process emissions only.

What you will find in Chapter 10:

This chapter provides several resources you may use to calculate your direct emissions from sector-specific processes.

Information you will need:

Your information needs will be based on the calculation methodology you select.

The California Registry's Cement Protocol provides guidance for calculating CO_2 emissions associated with manufacturing cement. Cement companies should refer to this document for procedures to account for process-related emissions from the calcination of clinker.

Power companies and utilities should refer to the Power/Utility Protocol for guidance on accounting for process-related emissions associated with emission control technologies, coal gasification, and hydrogen production.

A variety of useful resources exist that will help you calculate process emissions for which the California Registry does not provide guidance. The California Registry recommends reviewing relevant methodologies and/or calculations with technical assistance providers or other environmental experts.

Verification of emissions from manufacturing processes will be determined by the expertise and professional judgment of the verifier. Should you have questions about criteria or questions about a verifier's judgments during the verification cycle, you can contact the California Registry at any time.

The following is a list of resources for use in making your calculations:

Adipic acid production (process N_2O emissions)

- IPCC, *2006 Guidelines*, Equation 3.8
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Adipic Acid*, 2008

Aluminum production (process CO_2 and PFC emissions)

- CO_2: IPCC, *2006 Guidelines*, Equations 4.21 - 4.24
- PFC: IPCC, *2006 Guidelines*, Equations 4.25 - 4.27
- CO_2 and PFC: WRI/WBCSD, *Calculating CO_2 and PFC Emissions from the Production of Aluminum*, 2008

Ammonia production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equation 3.3
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Ammonia*, 2008

HCFC-22 production (process HFC-23 emissions)

- IPCC, *2006 Guidelines*, Equations 3.31 - 3.33
- WRI/WBCSD, *Calculating HFC-23 Emissions from the Production of HCFC-22*, 2008

Iron and steel production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equations 4.9 - 4.11
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Iron and Steel*, 2008

Lime production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Equations 2.5 - 2.7
- WRI/WBCSD, *Calculating CO_2 Emissions from the Production of Lime*, 2008

Nitric acid production (process N_2O emissions)

- IPCC, *2006 Guidelines*, Equation 3.6
- WRI/WBCSD, *Calculating N_2O Emissions from the Production of Nitric Acid*, 2008

Pulp and paper production (process CO_2 emissions)

- IPCC, *2006 Guidelines*, Section 2.5
- International Council of Forest and Paper Associations (ICFPA), *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, Version 1.1, 2005
- European Union, *Guidelines for the monitoring and reporting of greenhouse gas emissions*, 2006, Annex XI
- WRI/WBCSD, *Calculating GHG Emissions from Pulp and Paper Mills*, 2005

Semiconductor manufacturing (process PFC and SF_6 emissions)

- IPCC, *2006 Guidelines*, Equations 6.7 - 6.11
- WRI/WBCSD, *Calculating PFC Emissions from the Production of Semiconductor Wafers*, 2001

Other Resources

- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council

for Sustainable Development. The calculation tools are available from the GHG Protocol Initiative website at www.ghgprotocol.org/standard/tools.htm.

- EPA Climate Leaders Greenhouse Gas Inventory Guidance, U.S. Environmental Protection Agency, provides modified guidance from the World Resources Institute and World Business Council for Sustainable Development. See www.epa.gov/climateleaders/index.html.

Chapter 11 Direct Fugitive Emissions

Who should read Chapter 11:

Chapter 11 applies to organizations with fugitive emissions only.

What you will find in Chapter 11:

This chapter provides guidance on determining direct fugitive emissions, specific guidance and an example on fugitive refrigerant emissions of HFCs, and guidance on additional resources to use for other fugitive emissions.

Information you will need:

To complete this chapter you will need information on the types and quantities of air conditioning equipment, total refrigerant charge, annual leak rates, and the types of refrigerant, as applicable.

Cross-References:

See Chapter 5 on De Minimis Emissions and Significance in estimating HFCs from refrigerants.

Power companies and utilities should refer to the Power/Utility Protocol for guidance on accounting for fugitive emissions associated with electricity transmission and distribution, fuel handling and storage, air conditioning and refrigerant systems, and fire suppression equipment.

The majority of fugitive GHG emissions are specific to various industrial sectors or processes, including: manufacturing, natural gas transport and distribution, coal mining, waste management, wastewater treatment, and refrigerant leakage from air conditioning and refrigeration equipment. This chapter provides specific guidance on direct fugitive emissions from air conditioning, refrigeration, and fire suppression systems below. It also provides a list of resources for calculating other types of fugitive emissions.

III.11.1 Calculating Direct Fugitive Emissions from Refrigeration Systems

Leakage from refrigeration systems, such as air conditioners and refrigerators, is common across a wide range of entities. Only those refrigerants that contain or consist of compounds of the required GHGs should be reported (see Table III.11.1). Hydrofluorocarbons (HFCs) are the primary GHG of concern for refrigeration systems, particularly for motor vehicle air conditioners. Today, HFC-134a is the standard refrigerant for mobile air conditioning systems. For most California Registry participants, emissions of HFCs from refrigeration, air conditioning systems, and fire suppression equipment will be negligible in comparison to other GHG emissions.

Table III.11.1 HFCs and PFCs to be Reported

HFC-23	HFC-143a	HFC-4310mee	C_4F_{10}
HFC-32	HFC-152a	CF_4	C_6F_{14}
HFC-125	HFC-227ea	C_2F_6	
HFC-134a	HFC-236fa	C_3F_8	

Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003, Table 1-2 (April 2005).

Please note that many common refrigerants are blends of multiple HFCs. Table III.11.2 provides some examples of refrigerant blends and their composition. When calculating the emissions related to refrigerant blends, these blends must be broken down and reported as their constituent parts.

Table III.11.2 Composition of Refrigerant Blends

Blend	HFC 32	HFC-125	HFC-134a	HFC-143a
R404A	NA	44%	4%	52%
R407C	23%	25%	52%	NA
R507	NA	50%	NA	50%
R507	NA	50%	NA	50%

Use the following three step process to calculate HFC emissions:

1. Determine whether HFC emissions are significant or de minimis (see Chapter 5 for guidance on de minimis);
2. Perform a mass balance calculation; and
3. Convert each HFC emission to CO_2e.

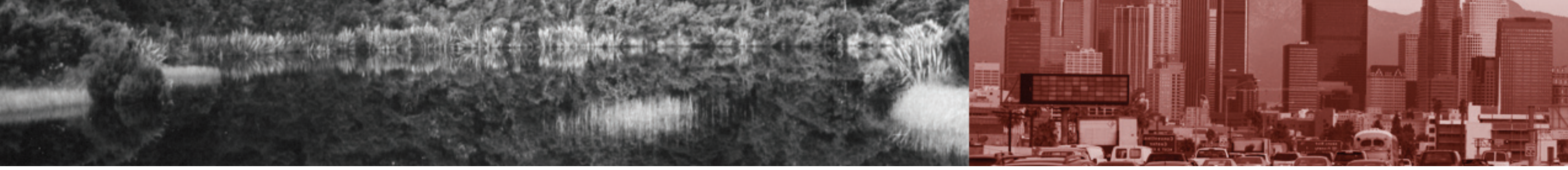


Table III.11.3 Loss Rates for Refrigeration and Air Conditioning Equipment
Note that all values are estimates and are intended only to serve as guidelines for evaluating de minimis.

Type of Equipment	Capacity (kg)	Annual Loss Rate (% of capacity)
Domestic Refrigeration	0.05 – 0.5	0.5%
Stand-alone Commercial Applications	0.2 – 6	15%
Medium & Large Commercial Refrigeration	50 – 2,000	35%
Transport Refrigeration	3 – 8	50%
Industrial Refrigeration (including food processing and cold storage)	10 –10,000	25%
Chillers	10 – 2,000	15%
Residential and Commercial A/C (including heat pumps)	0.5 – 100	10%
Mobile Air Conditioning	0.5 – 1.5	20%

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Volume 3: Industrial Processes and Product Use, Table 7.9.

Step 1 estimates whether your fugitive emissions are significant and warrant a more comprehensive review. If the fugitive emissions are not significant, and you wish to categorize them as de minimis, you do not need to complete this section. To perform the significance analysis, you will need information on:

- The types and quantities of air conditioning and refrigeration equipment;
- The total refrigerant charge;
- The annual leak rates; and
- The types of refrigerant.

If you find that your fugitive emissions are indeed significant, continue to Steps 2 and 3 for a more accurate quantification of HFC emissions.

Step 1: Determine whether HFC emissions are significant or de minimis.

This step helps organizations roughly estimate emissions and determine whether HFC emissions are significant or de minimis. Consistent with the California Registry's definition of significance, fugitive HFC emissions greater than or equal to 5% of a participant's total emissions are considered significant, assuming the participant has no other de minimis emissions. Fugitive emissions less than 5% can be considered de minimis, and should be reported as such. However, if fugitive emissions are considered substantial and possibly significant, then a more comprehensive and accurate mass balance approach is required to determine actual emissions.

Ozone Depleting Refrigerants and Climate Change

Did you know that not all refrigerants that affect climate change are considered greenhouse gas emissions? A number of widely-used refrigerants, including R-22 (more commonly known as Freon), are classified as ozone depleting substances (ODS) and are being phased out under the Montreal Protocol, an international treaty designed to protect the ozone layer that entered into force in 1989. While these substances do have a global warming potential, and therefore contribute to climate change, they are not classified as greenhouse gas emissions under the Kyoto Protocol because they are already being phased out under the Montreal Protocol.

When assessing your fugitive emission sources, please keep in mind that CFCs and HCFCs, including Freon, should not be included in your emissions report. You should only include emissions of the HFCs and PFCs listed in Table III.11.1 in this chapter. For more information on ozone-depleting substances and the Montreal Protocol, visit EPA's ozone depletion website at www.epa.gov/ozone/strathome.html.

To estimate emissions using this estimation method, follow these three steps:

- Determine the types and quantities of refrigerants used;
- Estimate annual emissions of each type of HFC; and
- Convert to units of carbon dioxide equivalent and determine total HFC emissions.

Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number and types of refrigeration and air conditioning equipment, by equipment category; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment. If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table III.11.3.

Estimate annual emissions of each type of HFC.

For each type of HFC, use Equation III.11a to estimate annual emissions. Default loss rates are provided in Table III.11.3 by equipment type.

Equation III.11a	HFC Emissions from Refrigerant Leakage			
HFC Emissions from Refrigerant Leakage (kg)	=	Total Annual Refrigerant Charge (kg)	x	Assumed Annual Leak Rate (%)

Convert HFCs to carbon dioxide equivalent.

Use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert HFCs to carbon dioxide equivalent. If the sum of the CO_2e emissions for HFCs (plus other estimated de minimis emissions) is less than 5% of total assumed emissions, report these emissions as de minimis; no further calculations are needed.

Proceed to Steps 2-3 if your HFCs are significant.

Step 2: Mass Balance Calculation: Determine base inventory for each HFC and calculate changes to base inventory.

Step 2 utilizes a comprehensive, mass balance approach to accurately determine HFC emissions. Essentially, the mass balance method works by starting with a base inventory of all HFCs in use, and adjusts that total based on purchases and sales of HFCs, and changes to the total refrigerant charge remaining in the equipment. The used HFCs that cannot be accounted for are assumed to have been emitted to the atmosphere. The four elements of these adjustments and changes are described here, with references to Tables III.11.4 and III.11.5, as applicable.

Base Inventory. The first step in calculating HFC emissions is to determine the difference between the quantity of the HFC in storage at the beginning of the year **(A)** and the quantity in storage at the end of the year **(B)**, as shown in Table III.11.4. Note, this quantity will be negative if the inventory increases over the course of the year. Those HFCs contained in cylinders and other storage containers are considered to be HFCs "in inventory"—not HFCs held in operating equipment.

Table III.11.4 Base Inventory

	Inventory	Amount (kg)
A	Beginning of year	
B	End of year	

Table III.11.5 Inventory Changes

	Inventory	Amount (kg)
	Additions to Inventory	
1	Purchases of HFCs (including HFCs in new equipment)	
2	HFCs returned to the site after offsite recycling	
C	Total Additions (1+2)	
	Subtractions from Inventory	
3	Returns to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and sent offsite for recycling or reclamation	
D	Total Subtractions (3+4+5)	
	Change to Full Charge/Nameplate Capacity	
6	Total full charge of new equipment	
7	Total full charge of retiring equipment	
E	Change to nameplate capacity (6-7)	

Additions and subtractions refer to HFCs placed in or removed from the stored inventory, respectively. The next items in calculating HFC emissions include purchases or acquisitions of refrigerant, sales or disbursements of refrigerant, and any changes to total full charge of refrigeration equipment.

Purchases/Acquisitions of Refrigerant. This is the sum of all the HFCs acquired during the year either in storage containers or in equipment **(C)**, as shown in Table III.11.5.

Sales/Disbursements of Refrigerant. This is the sum of all the HFCs sold or otherwise disbursed during the year either in storage containers or in equipment **(D)**, as shown in Table III.11.5.

Change to Total Full Charge of Equipment. This is the net change to the total equipment volume for a given HFC during the year **(E)**, as shown in Table III.11.5.

Note that the change to total full charge of equipment refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new equipment is purchased, the HFC that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of refrigerant recovered from retiring equipment is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring equipment has a total full charge larger than the total full charge of the new equipment.

To sum the total annual emissions of each type of HFC, use Equation III.11b.

Equation III.11b	Total Annual Emissions from Refrigerant Leakage
Total Annual Emissions	= A - B + C - D + E

Step 3: Convert HFC emissions to CO_2e (and convert to metric tons) and sum all subtotals.

Finally, use the IPCC Second Assessment Report global warming potential factors from Table C.1, Appendix C to convert each HFC to carbon dioxide equivalent, and sum the totals.

III.11.2 Fugitive Emissions from Fire Suppression Equipment

Your organization may use HFCs in its fire suppression equipment, including hand-held fire extinguishers. HFCs are the most widely employed replacements for Halon 1301 in total flooding applications, and are also employed as replacements for Halon 1211 in streaming applications. Since the production and sale of halons were banned in the United States in 1994, these non-ozone depleting extinguishing agents have emerged as the halon replacement agent of choice in some applications.

As fire protection equipment is tested or deployed, emissions of these HFCs are released. Thus, if you own or operate fire suppression systems and equipment and have tested or deployed these systems, you should assess whether any HFCs have been released. The mass balance approach described in Section III.11.1 can be used for determining emissions from fire suppression systems.

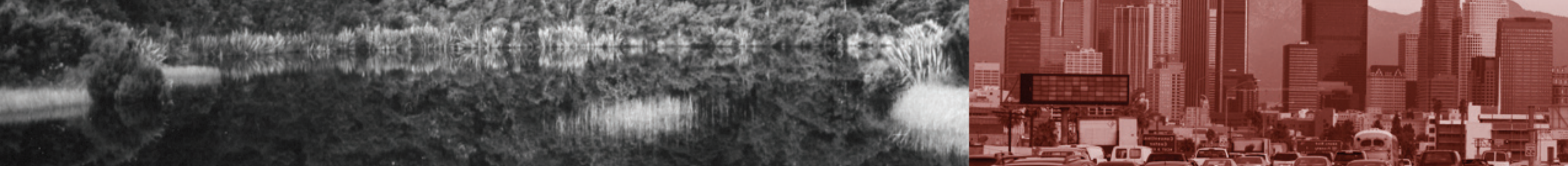
III.11.3 Other Fugitive Emissions

A variety of useful resources exist that may help you to calculate other fugitive emissions. The California Registry recommends reviewing relevant methodologies and/or calculations with technical assistance providers or other environmental experts.

Verification of fugitive emissions will be determined by the expertise and professional judgment of the verifier. Should you have questions about criteria or questions about a verifier's judgments during the verification cycle, you can contact the California Registry at any time.

The following is a list of resources for use in making your calculations:

- Local Government Operations Protocol, California Climate Action Registry. This protocol provides guidance on reporting methane emissions from solid waste facilities and methane and nitrous oxide emissions from wastewater facilities (www.climateregistry.org).
- Corporate GHG Accounting Calculation Tools, prepared under the GHG Protocol Initiative by the World Resources Institute and World Business Council for Sustainable Development (2004) (www.ghgprotocol.org/standard/tools.htm).
- Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme, prepared by the U.K. Department for Environment, Food and Rural Affairs (August 2001) (www.defra.gov.uk/environment/climatechange/trading).
- EPA Climate Leaders Inventory Protocol, U.S. Environmental Protection Agency (in development as of August 2002). EPA's protocol includes core modules addressing methane emissions from solid waste disposal at landfills as well as HFC emissions from refrigeration/air conditioning use (www.epa.gov/climateleaders/index.html).



- Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000, U.S. Environmental Protection Agency (April 2002) (www.epa.gov/globalwarming/publications/emissions/us2002/index.html).
- Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999, prepared by the California Energy Commission, November 2002 (www.energy.ca.gov/global_climate_change).
- American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry (2001).
- Guidance to the California Climate Action Registry: General Reporting Protocol, Appendix B and Appendix C, prepared by the California Energy Commission, P500-02-005F (June 2002), located at www.climateregistry.org. The following list of citations provide some guidance on quantifying direct fugitive emissions:
  - CH_4 emissions from coal mining: Appendix B page B-5, Appendix C page C-3
  - CH_4 emissions from natural gas systems: Appendix B page B-15, Appendix C page C-9
  - CH_4 emissions from petroleum systems: Appendix B page B-17, Appendix C page C-9
  - SF_6 emissions from electricity transmission and distribution equipment: Appendix B page B-6, Appendix C page C-4
  - N_2O emissions from wastewater: Appendix B page B-9
  - CH_4 emissions from wastewater: Appendix B page B-15
  - CH_4 emissions from landfills: Appendix B page B-10
  - N_2O emissions from agricultural soil management: Appendix B page B-2
  - CH_4 emissions from livestock as a result of enteric fermentation: Appendix B page B-7
  - CH_4 and N_2O emissions from manure management: Appendix B page B-13
  - CH_4 emissions from rice cultivation: Appendix B page B-18

III.11.4 Example: Direct Fugitive Emissions from Refrigeration Systems

Produce Chillers, Inc.

Produce Chillers, Inc. is based in California, and operates three large commercial refrigeration units, with an annual capacity of 1,225 kg HFC-23 per system, to refrigerate vegetable produce shortly after harvest, as well as three trucks that use HFC-134a for air conditioning.

Step 1: Determine whether HFC emissions are significant or de minimis.

Produce Chillers' first step is to determine whether its HFC emissions are significant. The upper bound loss rates for Produce Chiller's AC types are shown in Table III.11.3 and the excerpt below.

Air Conditioner Loss Rates for Produce Chillers, Inc.

Type of Equipment	Capacity (kg)	Annual Loss Rate (% of capacity)	Type of Refrigerant
Medium & Large Commercial Refrigeration	50 – 2,000	35%	HFC-23
Mobile Air Conditioning	0.5 – 1.5	20%	HFC-134a

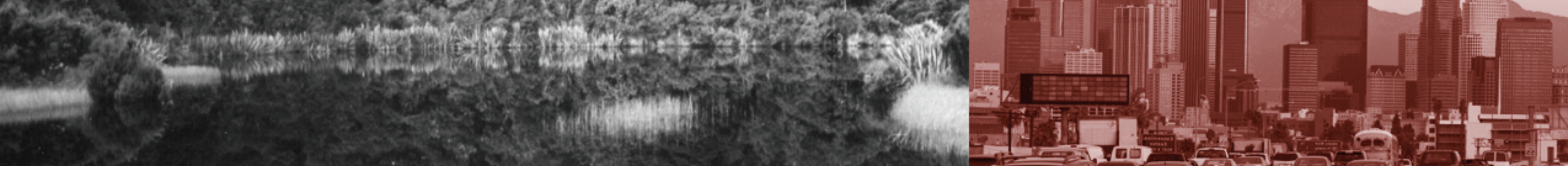
Produce Chillers then uses Equation III.11a to estimate assumed HFC emissions from air conditioning and refrigeration.

Equation III.11a	Assumed HFC Emissions from Annual Air Conditioning													
HFC Emissions from Annual Air Conditioning (kg)	=	Number of Systems	x	[	Total Annual Capacity (kg)	x	Operating Loss Rate (%/yr)	x	Years	]	÷	1,000		
3 Commercial Refrigeration Units	=	3	x	[	1,225	x	0.35	x	1	]	÷	1,000	=	1.286 metric tons HFC-23
3 Trucks	=	3	x	[	1.5	x	0.20	x	1	]	÷	1,000	=	0.0009 metric tons HFC-134a

Produce Chillers must then convert its assumed fugitive HFCs to CO_2e, using Equation III.6c

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent					
HFC-23 metric tons of CO_2e	=	1.286 metric tons HFC-23	x	11,700 (GWP)	=	15,046.2 metric tons CO_2e
HFC-134a metric tons of CO_2e	=	0.0009 metric tons HFC-134a	x	1,300 (GWP)	=	1.17 metric tons CO_2e
				Total	=	15,047.37 metric tons CO_2e

Produce Chillers has estimated that its total entity-wide GHG emissions are 50,000 metric tons. Consequently, they may choose to report up to 2,500 metric tons (i.e., 5% of 50,000 metric tons) as de minimis emissions. Its estimated fugitive emissions of HFC-23 are found to be significant, but HFC -134a can be classified and reported as de minimis. It must now calculate its HFC-23 emissions.



Step 2: Determine base inventory for HFC-23 and calculate changes to base inventory.

Produce Chillers increased its total vegetable produce refrigeration capacity by 18% with new equipment, decommissioned one refrigeration unit for recycling, and recharged several of its refrigeration units. It also purchased a new truck in the past year. Using Table III.11.4 it shows that the inventory at the beginning of the year is 812.6 kg and at the end of the year it is 805.1 kg.

Base Inventory for Produce Chillers, Inc.
HFC-23 from Commercial Chillers

	Inventory	Amount (kgs)
A	Beginning of year	812.6
B	End of year	805.1

Using its purchase and charge records, Produce Chillers calculates its total annual emissions using Table III.11.5 and Equation III.11b

Inventory Changes for Produce Chillers, Inc.
HFC-23 from Commercial Chillers

	Inventory	Amount (kgs)
	Additions to Inventory	
1	Purchases of HFCs (including HFCs provided by equipment manufacturers with or inside new equipment)	197.5
2	HFCs returned to the site after offsite recycling	0.0
C	Total Additions (1+2)	197.5
	Subtractions from Inventory	
3	Returns of HFCs to supplier	0.0
4	HFCs taken from storage and/or equipment and disposed of	0.0
5	HFCs taken from storage and/or equipment and sent offsite for recycling or reclamation	53.3
D	Total Subtractions (3+4+5)	53.3
	Change to Full Charge/Nameplate Capacity	
6	Total full charge of new equipment	19.5
7	Total full charge of retiring equipment	0.0
E	Change to nameplate capacity (6-7)	19.5

Equation III.11b	Total Annual Emissions of HFC-23 (kgs)			
Total Annual Emissions	=	A - B + C - D + E		
Total Annual Emissions HFC-23	=	812.6 – 805.1 + 197.5 – 53.3 + 19.5	=	171.2 kg HFC-23

Step 3: Convert HFC emissions to CO_2e and convert to metric tons.

Equation III.6c	Converting Mass Estimates to Carbon Dioxide Equivalent							
Metric tons of CO_2e	=	Metric tons of GHG	x	GWP (SAR, 1996)				
HFC-23 metric tons of CO_2e	=	132.2 kg HFC-23	x	11,700 (GWP)	x	0.001 metric tons/kg	=	1.5467 metric tons CO_2e
						Total	=	1.5467 metric tons CO_2e

Chapter 12 Optional Reporting

> **Who should read Chapter 12:**
>
> Chapter 12 applies to all participants.
>
> **What you will find in Chapter 12:**
>
> This chapter provides resources for calculating and/ or estimating emissions from sources that are not required to be reported, such as from employee commuting, business travel, waste, and more.
>
> **Information you will need:**
>
> You will need information about the size and nature of GHG emitting operations throughout your organization.
>
> **Cross-References:**
>
> It will be useful to consider your geographical and organizational boundaries addressed in Chapters 1 and 2, operational boundaries considered in Chapter 3, and all relevant quantification issues raised in Chapters 5-11.

In addition to reporting required emissions, you can also provide information to the California Registry about other activities of your organization that can help describe your entity's GHG activities and inventory.

Examples of these include:

- Renewable Energy Certificate purchases;
- Off-site waste disposal, including transport;
- Employee commuting, including business travel;
- Production of purchased raw materials, including transport;
- Product use and disposal; and
- Outsourced activities and contracting (especially if, in prior years, you generated these emissions directly).

You can also provide descriptive information about your organization's programs, projects to reduce emissions, environmental goals, and awards and choose to provide quantitative information, including reporting of emissions efficiency metrics or other indirect emissions.

A key feature of the California Registry's program is the reporting of efficiency metrics. GHG emissions are sometimes reported on a normalized basis – as a ratio – instead of, or in addition to, reporting in absolute terms. Normalized emissions are emissions divided by some measure of output for the reporting entity. The specific output measure depends on the nature of the organization that is reporting and may range from physical units of output (e.g., pound of cement for a cement plant) to economic output (e.g., dollars of revenue for a diversified manufacturer). Reporting normalized emissions allows trends in the emissions intensity of an activity to be gauged by removing the effects of changing outputs on the results. The common term for these measures is "efficiency metrics". Sample efficiency metrics are listed in Appendix F.

III.12.1 Reasons to Report Optional Information

There are potentially many reasons to report optional information:

- To provide a more complete or descriptive picture of your organization's environmental performance.
- To centralize information pertaining to other GHG accounting programs.
- To track other internal programs to monitor GHG emissions performance related to other corporate programs.
- To provide greater public education on sources of GHG emissions.

There are no California Registry-approved protocols for reporting or verifying optional information. Even so, reporting optional sources can serve to improve your organization's understanding of its emissions and its emission performance over time.

Also, the California Registry encourages you to document and report your GHG emissions internationally in the same categories as you report your California or U.S. emissions. While international emissions cannot currently be verified with the California Registry, doing so will only increase your ability to measure and manage your total emissions.

In the process of developing industry-specific guidance, additional recommendations may be developed for optional information reported by industry.

III.12.2 Efficiency Metrics

Many organizations experience business growth and thus their total emissions may increase from year-to-year, regardless of their organization's operational efficiency. Such organizations, in addition to reporting their total

emissions, may also elect to report efficiency metrics that measure GHG emissions per unit of performance or output (e.g., lbs CO_2/ft^2 of office space, lbs CO_2/customer, lbs CO_2/kWh, lbs CO_2/$ of revenue, etc.). A list of some industry-specific metrics is provided in Appendix F. This information may be reported in CARROT at either the entity- or facility-level, but CARROT is not able to calculate this statistic for you.

For organizations reporting under the General Reporting Protocol, metrics are optional. As the California Registry develops its industry-specific reporting guidance, affected industries may be required to report one or more metrics appropriate to their industry; for instance, power sector companies are required to report three metrics according to the Power/Utility Protocol as well as cement companies under the Cement Protocol.

III.12.3 Other Emissions Information

When reporting information in CARROT, the tool will prompt you to provide descriptive information about your organization in the following areas:

Entity description – You can provide basic information about your organization, including size, types of business and products, number of employees, etc.

Emission management programs—In this section, you can document the efforts of your organization to monitor and evaluate how and where your organization is producing GHG emissions. This could also include a description of other GHG accounting programs to which your organization belongs.

Emission reduction goals –You can enter information on your organization's goals to decrease your emissions of GHGs.

Emission reduction projects—Until additional guidance is developed to provide standardized, verifiable accounting principles for discrete projects to reduce emissions, you can provide descriptions of specific activities, as well as provide a limited amount of statistical information.

Link to external website—You can provide a link or links to external websites that contain information about your organization.

Space constraints in CARROT may limit how much information can be entered, but you can provide your own categories and update this information from year-to-year. You can also upload related documents in CARROT and attach them to your public emissions report.

III.12.4 Optional Indirect Emissions

In addition to reporting indirect emissions from your electricity use, you are encouraged to optionally report other indirect GHGs. Examples of other sources of indirect emissions that you may choose to report include:

- Off-site waste disposal, including transport;
- Employee commuting, including business travel;
- Production of purchased raw materials, including transport;
- Product use and disposal; and
- Outsourced activities and contracting.

The California Registry is still formulating specific guidance on estimating emissions from additional indirect sources such as those listed above. However, a variety of useful resources exist that may help you to estimate emissions from these types of activities. Some of these include:

Off-site waste disposal, including transport

- EPA Climate and Waste Program, yosemite.epa.gov/oar/globalwarming.nsf/WARM?OpenForm

Employee commuting, including business travel

- Calculating GHG emissions from office-based organizations, www.ghgprotocol.org/calculation-tools and www.ghgprotocol.org/calculation-tools/service-sector
- Safe Climate, www.safeclimate.net/calculator
- Climate Care, www.climatecare.org/business

The California Registry will review optionally reported information of participants. It reserves the right to ask for appropriate modifications or removal of specific optionally reported information, if it deems such changes are necessary.

III.12.5 Biogenic Emissions

Biogenic CO_2 emissions are produced from combusting a variety of biofuels, such as biodiesel, ethanol, wood, wood waste, and landfill gas.

International consensus on the net climate impact from the combustion of these fuel sources has not yet been reached. But because of the distinction between biogenic and anthropogenic emissions, the emissions associated with the biofuels should not be included as direct stationary or mobile emissions in your inventory.

The GRP provides limited guidance on calculating and reporting biogenic emissions because participants are only required to report anthropogenic emissions in their emissions inventory. However, biogenic emissions may be reported optionally. Chapter 7 contains guidance to calculate mobile CO_2 emissions from biodiesel, and biogenic emission factors for mobile and stationary combustion are available in Appendix C, Tables C.3 and C.7, respectively, to aid in reporting these optional biogenic sources.

Please note that CH_4 and N_2O emissions from the combustion of biofuels are not considered biogenic and should be calculated and reported as part of your emissions inventory.

Part IV Completing and Submitting Your Report

Now that you have established your reporting parameters in Part II and quantified your emissions in Part III, you are ready to complete your annual GHG emissions report, verify your emissions, and submit your inventory to the California Registry.

Chapter 13, Reporting Your Emissions, describes the steps you need to follow to report your emissions using CARROT, the California Registry's online reporting tool, and the *CARROT Getting Started Guide Version 3* as well as the steps for formally registering your emissions report with the California Registry once you have received verification from a verifier.

Chapter 14, Verification, explains the verification process. This chapter includes an overview of the importance of verification, requirements for meeting verification standards, the process for identifying and working with verifiers, documentation and other items you will need to prepare for verification, the reports you and the California Registry will receive at the conclusion of the process, and the process for correcting your emissions report, if necessary.

Chapter 13 Reporting Your Emissions

Who should read Chapter 13:

Chapter 13 applies to all participants.

What you will find in Chapter 13:

This chapter provides guidance on submitting your emissions report to and accessing your report from the California Registry.

Information you will need:

In order to submit your GHG emissions report, you will need a password from the California Registry, as well as all the relevant information required in your report.

Cross-References:

It may be useful to review the requirements in Chapter 14 on Verification.

Now that you have established your reporting parameters in Part II and quantified your emissions in Part III, you are ready to report your emissions to the California Registry using the California Registry's online reporting tool, CARROT.

IV.13.1 Submitting Your Report Using CARROT

You must report your organization's annual GHG emissions report via the California Registry's web-based reporting application and database, known as the Climate Action Registry Reporting Online Tool (CARROT).

CARROT has four main functions:

1. Helps California Registry participants calculate their annual GHG emissions and/or report these emissions to the California Registry.
2. Allows approved verifiers to review participants' annual GHG emissions reports and submit their verification information to the California Registry.
3. Permits the general public to view aggregated reports of participants' annual GHG emissions and their progress in managing these emissions.
4. Enables California Registry staff to efficiently manage and track participants' data.

CARROT provides you with a secure, online workspace to manage, report, verify, and register your emissions.

The California Registry has designed CARROT to facilitate and ease emissions reporting. CARROT is also designed to streamline the emissions registration process by providing emissions calculations tools, simple reporting features, and administrative controls that allow participants to delegate reporting within your organization.

When you join the California Registry, your organization's technical contact will be provided a UserID and Password that will allow you to access CARROT through the California Registry's website, www.climateregistry.org/CARROT. Other users within your organization can request access from your organization's technical contact.

IV.13.2 CARROT Guidance and Technical Assistance

If you have questions about using CARROT, the California Registry provides reporting assistance and support through the following tools:

- *CARROT Getting Started Guide Version 3* (December 2008), available on the California Registry website in PDF format
- CARROT online help and online documentation
- Email user support at help@climateregistry.org
- Phone user support (213-891-1444, extension 2)

Prospective participants and other interested parties can see how CARROT works by viewing a short demonstration of the tool, accessible on the California Registry's website (www.climateregistry.org/CARROT/Demo). Participants can also familiarize themselves with CARROT by using the CARROT Training Site. Access to the training site may be requested by sending an email to help@climateregistry.org.

IV.13.3 Accessing Your Verified Emissions Data

CARROT provides a variety of tools to help you manage and use your emissions data, and will be regularly updated to reflect current emissions reporting policies. The following are some of the features that will assist you in managing your reported GHG emissions information.

Participant's Administrative Module

CARROT allows you to manage separate emissions submissions, as needed, from within your organization, depending on how many individuals are responsible for reporting a subset of your total GHG emissions report. This is done by creating different types of users within CARROT.

Administrators are responsible for managing each entity's annual emissions report, creating other users to help them input or review data, and submitting an entity's report for verification and finally to the California Registry. They have full read/write access to data for all reported years.

Users are assigned to one or more facilities, and can enter information for specific locations for specific years and submit it to the Administrator for review.

For example, if your organization owns and operates five different facilities, the Administrator can grant permission to five different facility managers to enter the GHG emissions information from their respective facilities. The Administrator will be able to visually assess the status of each of the five facilities and will be the only party with the permission to submit and classify the entity emissions report as "Verification Ready".

Participant Database Query and Reporting

Once you have entered your emissions data, CARROT helps you generate detailed and summary reports of your information. Examples of CARROT reports include:

Reports for Participants

- Total Reported Emissions – Entity
- Total Reported Emissions – by Facility (if applicable)

Reports for the Public

In addition to collecting your GHG emissions data, CARROT will also make limited information about your GHG emissions report and overall California Registry participation available to the public. The public will see the following information, which you are required to report:

- Company name, address, and contact;
- Reporting year;
- Total emissions, by gas and by category (i.e., stationary combustion, mobile combustion, process emissions, fugitive emissions, indirect emissions and de minimis emissions); and
- Baseline year (if chosen).

In addition, the public will see the following information that you may choose to report. This optional information is not verified.

- Reduction goals, projects, management programs
- Entity description
- Total optional emissions, by gas and by category
- Other optional information

Archive Feature

CARROT maintains annual versions of your GHG emissions report submissions. Also, CARROT will keep copies of any revisions with your comments, to enable you to correct your submissions, and for California Registry-approved verifiers to verify your data. You can revise your report at any time; however, once it has been submitted for verification, any subsequent changes will need to be re-verified.

IV.13.4 Movement Reports

For every year of emissions data collection, CARROT will ask you to prepare a Movement Report, in which you identify the major factors that have affected your emissions. The Movement Report is required each year after your first year of reporting.
This should include:

- A list of structural changes (e.g., mergers, acquisitions, divestitures, outsourcing);
- A discussion of how your organization's business cycle is affecting your emissions; and
- A list of any emission reduction projects undertaken by your organization.

Table IV.13.1 provides a sample Movement Report.

Table IV.13.1 Sample Movement Report

Factor Affecting Performance	Details
Structural Change: Acquisition Divestiture Insourced Activities Outsourced Activities Leakage	Name Location Business Unit Affected Change due to California Registry participation Estimated impact on emissions
Organic Growth or Decline: New Construction Plant Closing Decrease in Production Increase in Production Business Cycle Fluctuation	Name Location Business Unit Affected Estimated Impacts on Production Estimated impact on emissions
Emission Reduction Activities: Purchased Offsets Avoided Emissions Sequestration	Project Name Location Estimated impact on emissions
Other	

For each category, CARROT will ask you to provide an explanation of each change to emissions, as well as an estimate of the impact on your total emissions. Thus, for an acquisition, you would indicate the name, location and size of the acquisition, and the estimated associated emissions per year (tons CO_2e/year).

One purpose of this Movement Report is to facilitate verification. Verifiers will reference this Movement Report to understand changes in your emissions data from year to year; however, this information will not be verified for accuracy nor provided to the public.

IV.13.5 Utilizing Your Verified Emissions Data

While the California Registry cannot predict the full range of ways you can utilize your verified emissions data, there are some important uses that are worth considering. For example, once you have started entering your information in the California Registry's CARROT reporting system, you will be able to maintain and track your organization's progress in meeting internal GHG reduction targets with every annual GHG emissions report.

As mentioned earlier, under a possible future regulatory regime, your verified emissions data could provide the basis for any determination of protections or other regulatory rewards for taking early steps to reduce your GHG emissions. Future regulations by the State of California or the federal government might reward organizations that took significant steps to reduce GHG emissions. Similarly, your GHG emissions data might be applicable for participating in voluntary GHG emissions reduction programs, both in the United States and abroad, or ISO 14064[1] for GHG emission reduction practices.

In addition, you may publish your verified emissions data in order to demonstrate your organization's commitment to environmental goals and to addressing climate change, and to disseminate transparent information about the specific steps your organization has taken to achieve reductions in GHG emissions.

1 The ISO 14064 standards for greenhouse gas accounting and verification published in March 2006 by ISO (International Organization for Standardization) provide government and industry with an integrated set of tools for programs aimed at reducing greenhouse gas emissions, as well as for emissions trading (www.iso.org).

Chapter 14 Verification

Who should read Chapter 14:

Chapter 14 applies to all participants.

What you will find in Chapter 14:

This chapter provides guidance on the process for verifying your GHG emissions report, including how to obtain verification services from an approved verifier, and what you will need to prepare for verification.

Information you will need:

Chapter 14 will guide you through the steps involved in determining what information you will need for verification. Table IV.14.1 in this chapter provides a list of specific documentation that will be needed for verification.

Cross-References:

All other chapters in the General Reporting Protocol may be considered during the verification process. In addition, you should review the General Verification Protocol, to be used by approved verifiers, in preparing for verification.

This chapter provides context for the principles underlying verification, explains the verification standards, and overviews the entire verification process.

This General Reporting Protocol is designed to direct the complete, transparent, and accurate reporting of your organization's GHG emissions. Verifying your emissions report is the final step in the reporting process.

Verification is the process used to ensure that a participant's GHG emissions report has met a minimum quality standard and complied with an appropriate set of California Registry-approved procedures and protocols for submitting emissions inventory information. For most California Registry participants, meeting the requirements of the General Reporting Protocol should be sufficient to complete verification. Where a participant is eligible for an industry-specific protocol, they will need to meet those requirements to achieve verification. Participants with relatively small and simple emissions (<500 tons CO_2e per year) may be eligible for batch verification - see Section IV.14.14 for more information on eligibility.

The California Registry's verification process has been designed to promote the credibility, accuracy, transparency, and usefulness of emissions data reported to the California Registry. Once an approved verifier has determined that the emissions report meets a minimum quality standard and is free of material discrepancies, the participant's reported emissions data will be reviewed by the California Registry and accepted into the California Registry's database.

If you are interested in understanding and preparing for the verification process in more detail, and to see the specific process approved verifiers will be using to verify your GHG emissions report, you may obtain a copy of the Verification Protocol, the California Registry's guidance for approved verifiers, from the California Registry's website.

IV.14.1 GHG Reporting Principles and Verification

The purpose of verification is to provide an independent review of data and information submitted to the California Registry, which ensures the credibility of the GHG inventories. To accomplish this objective, the independent verification process maintains the criteria of comparability, completeness, consistency, transparency, and accuracy as its underlying principles. These accounting and reporting principles are described in Section I.4.

IV.14.2 Verification Standard

At a minimum, each annual GHG emissions report (emissions report) must contain all of an entity's emissions of CO_2 in the state of California for a calendar year, reported in five categories: 1) indirect emissions from purchased electricity, imports of steam, district heating and cooling, and direct emissions from 2) mobile combustion, 3) stationary combustion, 4) process emissions, and 5) fugitive emissions. Where a participant is reporting its U.S. emissions, the report must contain all of their emissions nationally. Starting with the fourth year of reporting, each emissions report must contain all emissions of all six greenhouse gases (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6). If a participant is reporting process or fugitive emissions, a separate industry specific protocol may also be used and cited.

Emissions reports may also contain other information about an organization and its emissions that does not require verification. Your verifier will not consider this information when developing an opinion regarding your verifiable annual GHG emissions inventory results.

Additional guidance on reporting optional information is provided in Chapter 12.

IV.14.3 Minimum Quality Standard

An emissions report submitted to the California Registry must be free of material discrepancies to be verified. In other words, a verifier's calculation estimates of the entire inventory must not differ from a participant's estimates of the entire inventory by more than 5%. It is possible that during the verification process differences will arise between the emissions totals estimated by participants and those estimated by verifiers. Differences of this nature may be classified as either material or immaterial discrepancies. A discrepancy is considered to be material if the overall reported emissions differ from the overall emissions estimated by the verifier by 5% or more. Otherwise, it is immaterial.

IV.14.4 The Verification Process

The verification process outlined in the General Verification Protocol is designed to be applied consistently across all participants. However, based on the size and complexity of participants' operations and management systems, verification activities and the duration of the process will vary.

At a minimum the verification process will include the following steps:

- Conducting an evaluation of Conflict of Interest by the California Registry
- Providing notification of planned verification activities to the California Registry
- Scoping and planning a participant's verification activities prior to commencing verification
- Conducting verification activities in accordance with the General Verification Protocol
    - Identifying emissions sources
    - Reviewing methodologies and management systems
    - Verifying emission estimates
- Preparing a participant's Verification Report and Verification Opinion
- Submitting a Verification Opinion and Verification Activity Log to the Participant

Upon the completion of the above steps, the California Registry will accept a participant's verified data into its emissions database.

A step-by-step description of the verification process is described in Section IV.14.9.

Core Verification Activities

The verification process is designed to ensure that there have been no material discrepancies of your reported entity-wide inventory. In order to ensure consistency in the application of verification, the California Registry provides all verifiers with a General Verification Protocol that is based on the guidance contained in this Protocol and any industry-specific protocol. The General Verification Protocol is a guidance document. However, since verifiers face potential financial liability for reports they have verified, it is ultimately at the verifier's discretion whether to verify your report.

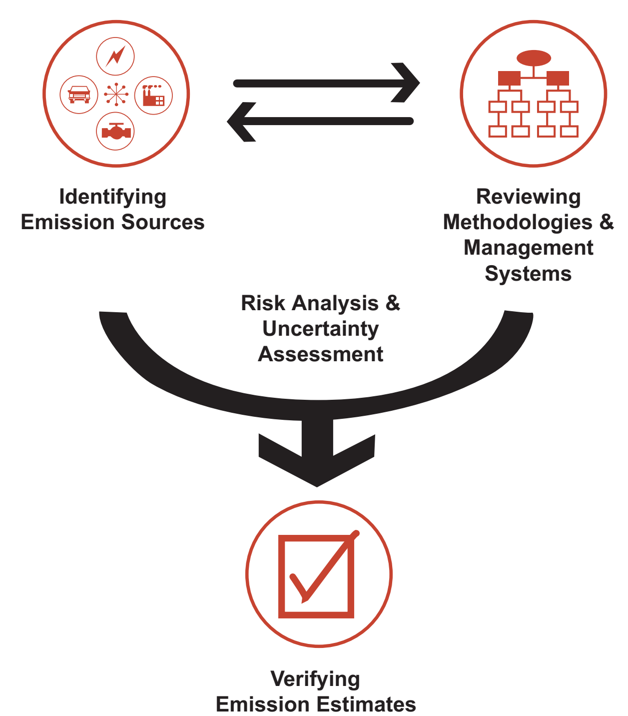
Once the verifier has completed the preparations for verification, including the kick-off meeting and the selection of a general approach to verification, the core verification activities can begin.

The core verification activities include three primary elements:

1. Identifying emissions sources;
2. Understanding management systems and estimation methods used; and
3. Verifying emissions estimates.

The core verification activities are fundamentally a risk assessment and data sampling effort aimed at ensuring that no significant sources are excluded and that the risk of error is assessed and addressed through appropriate sampling and review. The complete core verification process is illustrated in Figure IV.14.1.

Figure IV.14.1 Core Verification Process



IV.14.5 Professional Judgment

Approved verifiers must verify participants' annual GHG emissions reports against the California Registry's General Reporting Protocol using the process outlined in the General Verification Protocol. The California Registry asks verifiers to use their professional judgment when executing the verification activities described in the General Verification Protocol. The purpose of the verifier accreditation process is to ensure that verification firms demonstrate, through their staff's professional qualifications and experience, their ability to render sound professional judgments about GHG emissions reports.

Application of a verifier's professional judgment is expected in the following areas:

- Implementation of verification activities with appropriate rigor for the size and complexity of a participant's organization and with regard to the uncertainty of calculations associated with the participant's emissions sources;
- Review of the appropriateness of a participant's GHG emissions tracking and monitoring procedures, calculation methodologies, and management systems for providing information to the California Climate Action Registry;
- Evaluation of participant compliance with the California Registry's General Reporting Protocol;
- Assessment of methods used for estimating emissions from sources for which the General Reporting Protocol does not provide specific guidance, such as process and fugitive emissions, and indirect emissions from sources other than electricity, imported steam, and district heating and cooling; and
- Appraisal of assumptions, estimation methods, and emission factors that are selected as alternatives to those provided in the General Reporting Protocol.

The General Verification Protocol and training provided by the California Registry are intended to explain to the verifier the California Registry's guidelines and expectations and thus what types of professional judgments are appropriate for this program. In addition to these resources, verifiers and participants may contact the California Registry at any time for clarification of California Registry guidelines, expectations, and policies.

IV.14.6 Conflict of Interest

In order to ensure the credibility of the emissions data reported to the California Registry and its applicability under any future regulatory regime, it is critical that the verification process is completely independent from the influence of the participant submitting the emissions report. While conducting verification activities for California Registry participants, verifiers must work in a credible, independent, nondiscriminatory, and transparent manner, complying with applicable state and federal law and the California Registry's Conflict of Interest (COI) determination process.

Verification bodies must provide information to the accreditation body about their organizational relationships and internal structures for identifying potential conflicts of interest (organizational COI). Then, on an individual basis, the California Registry will review any pre-existing relationship between a verifier and participant and will assess the potential for conflict of interest (case-by-case COI) in conducting a verification. When the California Registry determines there is a low risk of COI, the participant and verifier can finalize negotiations of their contract. Following completion of a verification, the verifier must monitor their business relationships for the next year for situations that may create a COI (emerging COI) and notify the California Registry before entering into new business relationships with these participants.

This conflict of interest clause does not preclude a verifier from engaging in consulting services for other clients that participate in the California Registry for whom the verifier does not provide any verification activities.

Verifiers must submit an updated COI form each year, even if they have verified previous years' emissions reports for a participant.

As an added protection, a verifier may provide verification services to a California Registry participant for, at most, six consecutive years. After a six-year period, the California Registry participant must engage a different verifier. The original verifier may not provide verification services to that participant for three years. This three-year hiatus begins with any lapse in providing annual verification services to a California Registry participant.

In the event that a verifier violates these conditions, the accreditation body, at its discretion, may disqualify an approved verifier for a period of up to five years.

IV.14.7 Reporting and Verification Deadlines

You must submit your GHG emissions report by June 30 of the year following the emissions year to the California Registry to initiate verification activities. Verification should be completed by October 31 of the year the report is submitted to the California Registry. In other words, a GHG emissions report for 2008 emissions should be submitted by June 30, 2009, and the verification process should be completed by October 31, 2009.

Participants who are not able to meet these deadlines must request a reporting or verification extension from the California Registry.

Reporting Deadline: June 30

Verification Deadline: October 31

IV.14.8 State Role in Verification

The California Registry's enabling legislation directed two state agencies, the Resources Agency and the Environmental Protection Agency, to provide technical guidance to the California Registry, including developing verification procedures. The State of California helps the California Registry to oversee verification activities. This includes randomly accompanying verifiers on site visits to evaluate the participant's GHG reporting program and the reasonableness of the participant's reported data. The State has worked through the California Energy Commission, the California Air Resources Board, and the California Department of Forestry and Fire Protection to conduct this oversight.

IV.14.9 Key Verification Steps

Verification consists of a number of procedural steps that must be taken to ensure that the obligations and responsibilities of both the verifier and participant are clear, as well as verification activities that ascertain the accuracy and completeness of an emissions report.

The following summary of the major steps of the verification process is provided as a reference.

1. **Participant Selects Verifier:** The participant may contact one or more State- or California Registry-approved verifiers to discuss verification activities. The participant selects a company to verify its GHG emissions results and begins to negotiate contract terms.
2. **Verifier Submits Case-Specific Notification of Verification Activities and Request for Evaluation of Conflict of Interest Form:** After a participant chooses a verifier, the verifier must submit a Notification of Verification Activities and Conflict of Interest Evaluation Form to the California Registry at a minimum of 10 business days prior to beginning verification activities. This is to establish the plan and scope of verification activities, and to ensure that the likelihood of a COI between parties is low or that risk of any conflict can be sufficiently mitigated by the verification body.
3. **California Registry Sends COI Determination to Verifier:** The California Registry reviews the Evaluation of COI Form and supporting information to determine the level of risk associated with the proposed participant/verifier relationship, and notifies the verifier of its determination.
4. **Verifier and Participant Finalize Contract:** When the California Registry provides a favorable COI determination between a participant and a verifier, verifiers may finalize their contract with a California Registry participant.
5. **Verifier Conducts Verification Activities:** The verifier follows the guidance in the General Verification Protocol to evaluate a participant's annual GHG emissions report.
6. **Verifier Prepares Verification Report and Verification Opinion for Participant:** The verifier prepares a detailed summary (Verification Report) of the verification activities for the participant. The verifier also prepares a Verification Opinion for the participant's review, and a Verification Activity Log.
7. **Verifier and Participant Discuss Verification Report and Opinion:** The verifier meets with the participant to discuss Verification Report and Opinion.
8. **Verifier Completes Verification Form and Verification Activity Log via CARROT:** Once authorized by a participant, the verifier completes the Verification Form and Log via CARROT.
9. **Participant Forwards Verification Opinion to the California Registry:** The participant emails the original Verification Opinion to the California Registry.
10. **California Registry Completes Reporting Process:** The California Registry reviews the Verification Opinion and Verification Activity Log and evaluates the participant's emissions report. Once accepted by the California Registry, a participant's aggregated entity-level emissions become available to the public via CARROT.

IV.14.10 Preparing for Verification

The pre-verification process involves several steps, including:

- Identifying accredited verification bodies on the California Registry's website;
- Executing a competitive bid process or awarding a sole source contract for verification services, or, if you are eligible, participating in batch verification (see Section IV.14.14) through the California Registry;
- Negotiating your contract with your selected verifier; and

- Assembling relevant materials needed by the verifier to verify your emissions data.

Use of California Registry-Approved Verifiers. You must choose your verifier from the list of accredited verification bodies maintained by the California Registry. Information about California Registry-approved verification bodies is provided on the California Registry website at www.climateregistry.org/serviceproviders.

Request for Bids for Verification Services

Options for Soliciting Bids. The California Registry recommends that those participants with complex GHG emissions reports solicit competitive bids for verification services from at least three verification bodies. If your organization has prepared a simpler GHG emissions report and does not seek, or is not eligible for, batch verification, you may wish to either secure competitive bids or to sole-source the verification contract in order to reduce costs and expedite the verification process.

Non-Disclosure Agreements. When preparing to send out a request for bids from verifiers, you should review the list of approved verification bodies and select some or all as prospective bidders. The California Registry recommends that you send the contact person from each prospective bidder a non-disclosure agreement prior to requesting bids or releasing potentially proprietary information.

The Request for Bids. In order to obtain the most competitive bids and ensure that you will receive the most effective verification services, your request for bids should include as much detailed information about your organization and its emissions report as possible.

The California Registry recommends that participants include the following information in their requests for bids from verification bodies:

1. The expected contract duration;
2. A general description of the participant's organization;
3. The geographic boundaries of the participant's report;
4. The number and locations of facilities and operations;
5. The GHGs reported in the participant's emissions report;
6. The emission source categories (and possibly emission sources) in the participant's report; and
7. A copy of the participant's emissions report from CARROT.

You should request bids and negotiate terms and conditions for a complete verification, including:

- A review of your management systems (required in year one and recommended at least every third year thereafter);
- A review of your underlying activity data;
- Confirmation of emissions estimates;
- A final Verification Report; and
- A Verification Opinion submitted to the California Registry.

The California Registry suggests that participants request Commercial and Technical Proposals from potential verifiers that include the following components:

Commercial Proposal

1. History and description of company
2. Explanation of core competencies
3. Proposed price for verification services
4. Proposed staff
5. Statement of verifier liability
6. Confidentiality policy
7. Duration of contract

Technical Proposal

1. Approach to preparing for verification
2. Approach for completing core verification activities
3. Approach for completing the verification process

Negotiating a Contract with the Verifier

After you have selected a verifier from the approved verifiers that gave you bids, you should negotiate complete contract terms. This contract must be for direct services between the participant and an approved verifier. Contracts for verification services typically include the following components:

Scope of the Verification Process. This component of the contract will outline the exact geographic and organizational boundaries of the participant's emissions inventory to be examined. This should, but may not necessarily, match the boundaries used in the GHG emissions report to the California Registry. This scope will indicate whether California-only emissions are included or if both California and U.S. emissions are included. It will also include whether the participant has used the management control, equity share, or other method based on contractual relationships to determine organizational boundaries.

Confirmation of Approved Verifier Status. This is a simple statement that the verification body has been approved by the California Registry to verify emissions reports covering the scope listed above.

Verification Standard. Approved verifiers must verify participants' GHG emissions reports against the California Registry's General Reporting Protocol using the process

outlined in the General Verification Protocol. However, if a participant is reporting process or fugitive emissions, a separate industry-specific protocol may also be used and cited. Some participants may wish to use their GHG emissions report for additional purposes such as registering in another registry or participating in an emissions trading scheme or crediting program, etc., and thus may add additional standards for verification.

Non-Disclosure Terms. The verifier and the participant should agree in advance on methods for identifying and protecting proprietary and business confidential data that may be revealed during verification.

Site Access. The verifier and the participant should agree in advance to the time, place, and conditions of a verifier's site visits, if any are required.

Documentation and Data Requirements. The verifier and participant should agree on how and when the participant will provide emissions data to the verifier. The range of required documentation will largely be determined by the size and complexity of participant operations, and whether the participant has used the online calculation tools available through CARROT.

Period of Performance. The period of performance for verification services will typically be for three years, given that the verification process required by the California Registry is more streamlined in Year 2 and Year 3, if participant operations do not change. However, there may be instances where contracts are negotiated for a single year, pending renewal.

Performance Schedule. Participants and verifiers may wish to agree on a schedule to complete the verification process and for the verifier to deliver a Verification Report and Verification Opinion. Verification should be initiated in time to meet the October 31 verification deadline.

Payment Terms. Typical payment terms include total value, schedule of payments, and method of payment (e.g., electronic funds transfer).

Re-verification Terms. If the verifier identifies material discrepancies, the participant may choose to revise its GHG emissions report. At that time, the participant may ask the verifier to re-verify the report or seek verification from another provider. The verifier may not provide guidance, technical assistance or implementation work on the remediation of material misstatements, as this would be viewed as consulting services and result in a conflict of interest.

Liability. All verifiers are subject to the minimum liability associated with completing the verification per the terms of the verification contract. The participant may require and the verifier may agree to additional liability under this contract.

Contracts. The contract should identify technical leads for the participant and verifier, as well as responsible corporate officials of each party.

Verifier Requirement to Notify State of Verification

When the verifier submits the Notification of Verification Activities and COI Evaluation Form prior to beginning verification activities, the California Registry will notify the State of any and all planned verification activities at the time it makes its determination. This notification period is necessary to allow the State the opportunity to occasionally accompany verifiers on visits to participants' sites. The State observes, evaluates, and reports on the quality and consistency of verification activities. A verifier that does not provide proper notification to the California Registry at least 10 business days prior to beginning verification activities may be disqualified as an approved verifier.

Kick-off Meeting

After the verifier has notified the California Registry and the State of planned verification activities, verifiers should host a kick-off meeting with participants. Meetings can be conducted in person or by telephone. The agenda for that meeting should include:

1. Introduction of the verification team;
2. Review and confirmation of verification process and scope;
3. Transfer of background information and underlying activity data (see Table IV.14.1); and
4. Review and confirmation of the verification process schedule.

Based on the information provided in agenda items two and three, the verifier should determine the most effective, efficient, and credible detailed verification approach tailored to the particular characteristics of the participant.

IV.14.11 The Verification Cycle

While verification is required annually, in some instances it can be thought of as a three-year process. In Year 1, a verifier will need to form a detailed understanding of a participant's operations and consequential GHG emissions. Assuming that there have been no significant changes in the geographic and organizational boundaries of a participant's operations, a verifier is likely to have identified all emission sources and gained a sufficient understanding of the participant's GHG emissions management systems in Year 1 to streamline and

expedite the verification activities to focus on verifying emissions estimates in Year 2 and Year 3. To ensure data integrity, all of the core verification activities should be completed in Year 4.

Thus, the core verification activities each year will likely be as follows:

Year 1: **Identify Emission Sources, Review Management Systems, Verify Emissions Estimates**

Year 2: **Verify Emissions Estimates**

Year 3: **Verify Emissions Estimates**

Year 4: **Same as Year 1**

The California Registry assumes that verifiers will use their best professional judgment when conducting verification activities, and thus, will modify the suggested annual process described above as necessary. Each verifier is also required to complete a number of steps in their review, and to evaluate every participant against a number of criteria. These steps and criteria are listed in the Verification Activity Log, provided in the General Verification Protocol.

When you have specified a baseline, each year your verifier will need to identify changes to your direct emissions, review the cause of the changes, and assess if you have reached the baseline change threshold of 10%. The verifier will also determine if you have adjusted your baseline appropriately, if necessary.

As mentioned earlier, a verifier may provide verification services to a California Registry participant for, at most, six consecutive years (two verification cycles). After a six-year period, the California Registry participant must engage a different verifier and the original verifier may not provide verification services to that participant for three years.

IV.14.12 Online Reporting

If a participant chooses to use the built-in calculators and default emission factors in CARROT and the verifier's document review suggests that data have been collected properly and entered accurately, the verifier will not need to re-calculate the emissions, as the calculations will be automatic. Due to the time savings, this should result in a less expensive and expedited verification process.

IV.14.13 Documentation for Review

The documents that will need to be reviewed during verification will also vary depending on the nature of the emission sources contained in your GHG emissions report to the California Registry. Table IV.14.1 on the following page, provides a list of recommended documents to have ready to provide a verifier for conducting the verification process.

Table IV.14.1 Documents to be Reviewed During Verification Activities

Activity or Emissions Source	Documents
Identifying Emission Sources	
Emission Source Inventory	Facility inventory
	Emission source inventory Stationary source inventory Mobile source inventory Fuel inventory
Understanding Management Systems and Methodologies	
Responsibilities for Implementing GHG Management Plan	Organization chart, greenhouse gas management plan, documentation and retention plan
Training	Training manual, procedures manual, consultant qualification statement
Methodologies	Protocols used (if in addition to the California Registry's General Reporting Protocol)
Verifying Emission Estimates	
Indirect Emissions from Electricity Use	Monthly electric utility bills, emission factors (if not default)
Direct Emissions from Mobile Combustion	Fuel purchase records, fuel in stock, vehicle miles traveled, inventory of vehicles, emission factors (if not default)
Direct Emissions from Stationary Combustion	Monthly utility bills, fuel purchase records, CEMs data, inventory of stationary combustion facilities, emission factors (if not default)
Indirect Emissions from Cogeneration	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Indirect Emissions from Imported Steam	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Indirect Emissions from District Cooling	Monthly utility bills, fuel and efficiency data from supplier, emission factors (if not default)
Direct Emissions from Manufacturing Processes	Raw material inputs, production output, calculation methodology, emission factors
Refrigeration Systems	Refrigerant purchase records, refrigerant sales records, calculation methodology, emission factors
Landfills	Waste in place data, waste landfilled, calculation methodology, emission factors
Coal Mines	Coal production data submitted to EIA, quarterly MSHA reports, calculation methodology, emission factors
Natural Gas Pipelines	Gas throughput data, calculation methodology, emission factors
Electric Transmission and Distribution	Sulfur hexafluoride purchase records, calculation methodology, emission factors

IV.14.14 Batch Verification

In an effort to minimize the transaction costs of verification for small organizations with relatively simple emissions, the California Registry will contract with an approved verifier to undertake the verification work for interested participants with limited GHG emissions. The California Registry calls this batch verification. Emissions reports verified under batch verification must meet the same standards as non-batch reports. Eligible participants include those with:

- Less than 500 metric tons of CO_2e emissions per year;
- No significant process or fugitive emissions (de minimis emissions in these categories are allowed);
- Indirect emissions from purchased electricity at no more than four sites;
- Direct emissions from no more than five vehicles; and
- Direct emissions from stationary combustion at no more than one site.

Upon the recommendation of the batch verifier, the California Registry reserves the right to deem a participant's GHG emissions inventory too complex for batch verification. The California Registry also reserves the right to grant batch verification eligibility on a case-by-case basis.

Batch Verification Process Overview

The following is a summary of the steps of the batch verification process.

Participants interested in batch verification will notify the California Registry. After confirming the participant's eligibility, the California Registry will keep track of interested participants until a sufficient number have reported their emissions in CARROT and submitted the data for verification.

Each year, the California Registry will solicit competitive bids for batch verification services from at least three approved verifiers. On behalf of batch participants, the California Registry will select one verifier to perform all eligible verifications for that calendar year of emissions.

1. **Batch Verifier & Batch Participants Sign Contracts**: Each participant signs a standardized contract with the verifier. Any participant requiring non-standard contract language cannot participate in batch verification.
2. **Batch Verifier Receives Documentation:** After the entities participating in batch verification have completed their reports, the California Registry will collect the necessary supporting documentation from the participants and forward it to the verifier. Batch verification will not require a site visit, but will consist of document review and telephone interviews.
3. **Batch Verifier Conducts Verification Activities:** The verifier will follow the guidance in the General Verification Protocol to evaluate a participant's GHG emissions report. The verifier will contact each participant to understand their operations.
4. **Batch Verifier Provides Verification Report and Opinion to Participant:** The verifier prepares and discusses a summary of the verification activities with the participant (Verification Report). The verifier also provides the Verification Opinion to the participant. Once authorized by a participant, the verifier completes the Verification Form and Activity Log via CARROT.

The participant then emails the Verification Opinion to the California Registry at help@climateregistry.org.

The California Registry will review the Verification Opinion and Verification Activity Log and evaluate the participant's emissions report. Once accepted by the California Registry, a participant's aggregated entity-level emissions become available to the public via CARROT.

IV.14.15 Verification Report and Opinion

The verifier will prepare a detailed Verification Report for each emissions report. The Verification Report is a confidential document that is shared between a verifier and a participant—it is not available to the California Registry or the public unless a participant chooses to share it, or it is specifically requested by the California Registry.

Verification Report

The Verification Report should include the following elements:

- The scope of the verification process undertaken;
- The standard used to verify emissions (this is the California Registry's General Reporting Protocol, but may also include other protocols or methodologies for those sources for which the California Registry has yet to provide detailed guidance);
- A description of the verification activities, based on the size and complexity of the participant's operations;
- A list of emissions sources identified;
- A description of the sampling techniques and risk assessment methodologies employed for each source;
- An evaluation of the participant's emissions report compliance with the California Registry's General Reporting Protocol;
- A comparison of the participant's overall emission estimates with the verifier's overall emission estimates;
- A list of material discrepancies, if any;

- A list of immaterial discrepancies, if any; and
- A general conclusion to be reflected in the Verification Opinion forwarded to the California Registry.

A participating organization should be provided up to 30 days to review and comment on the Verification Report. At the end of that review, the verifier and the participating organization should hold a meeting to discuss the nature of any material or immaterial discrepancies.

Verification Opinion

The Verification Opinion is a simple confirmation of the verification activities and outcomes for all stakeholders (participants, verifiers, the California Registry, and the public). The Verification Opinion must also follow the same internal review process as the Verification Report, and consequently must be reviewed and signed by the verification firm and submitted by the participating organization.

Exit Meeting

Verifiers should prepare a brief summary presentation of their verification findings for the participant's key personnel. At the exit meeting verifiers and participants might exchange lessons learned about the verification process and share thoughts for improving the verification process in the future. Verifiers and participants may wish to consider joint feedback to the California Registry.

The goals of this meeting should be:

- Acceptance of the Verification Report and Opinion (unless material discrepancies exist and can be remediated, in which case the verification contract may need to be revised, and a re-verification scheduled). If the participant does not wish to retain the verifier for the re-verification process, the verifier shall turn over all relevant documentation to the participant within 30 days.
- Authorization for the verifier to complete the Verification Form in CARROT.

IV.14.16 Submitting a Verified Emissions Report to the California Registry

Once a participant authorizes the Verification Opinion, the verifier must complete the electronic Verification Form in CARROT and send the original Verification Opinion to the participant. The participant must forward the original copy of the Verification Opinion to the California Registry.

Once the electronic Verification Form is completed and the California Registry receives a hardcopy of the Verification Opinion, the participant's report will be reviewed and formally accepted into the California Registry database, and the annual verification process will be completed.

Participants are not required to submit their Verification Opinions to the California Registry for the first two years of their participation. However, a participant's emissions data will not be considered accepted by the California Registry unless the California Registry receives a Verification Opinion indicating a "verified without qualification" assessment.

IV.14.17 Record Keeping and Retention

You should maintain any relevant records from which emissions results have been calculated. Such records may include, but not be limited to, utility bills, fuel consumption records, emissions data, process data and schedules, and past reports. Although it is not possible to predict what any future regulatory regime may require regarding record keeping and retention, it is inadvisable for you to dispose of relevant records immediately after filing emissions reports. This would hinder any future verification or review activities, placing you at a disadvantage in case of some need to re-estimate the emissions results. In addition, your baseline inventory data is the key to determining temporal trends in GHG emissions.

IV.14.18 Correcting or Revising Your GHG Emissions Report

After you have submitted your verified GHG emissions report to the California Registry, you will still be able to make corrections if you have determined an error in your report, have identified new emissions sources, or would like to utilize more thorough calculation methodologies to estimate your emissions. You should note that the California Registry's reporting system is designed to retain all original reports and records it receives as archives, even after a GHG emissions report has been corrected or updated.

Should you update your GHG emissions report, the updated portion will need to be re-verified by a California Registry-approved verifier, following the process described in this chapter. Note that if the specific changes you have made to your report influence or affect the estimations of other elements of your report, you will again need to have the verifier review and verify all relevant sections of your GHG emissions report. Where your overall corrections result in an insignificant change in emissions from your previous GHG emissions report, verification should require only verifying your emissions estimates. Once a revision is initiated in CARROT, the information is not publicly available until all additions to the report are verified.

IV.14.19 Dispute Resolution

There may be instances where a verifier and a participant cannot agree on identification of material discrepancies and/or the findings of the Verification Opinion. In such instances, both parties can request the Dispute Resolution Committee, composed of qualified representatives from California state agencies, the California Registry, and one non-voting verifier, who serves pro bono on an annual, rotating basis. The participant and the verifier will each pay a filing fee equal to 5% of the participant's annual California Registry membership fee to submit the matter to the Dispute Resolution Committee.

The Dispute Resolution Committee will interview the participant and the verifier, review the area of dispute and reach a unanimous, binding decision concerning verifiability. The California Registry will notify the verifier and California Registry participant of the Committee's decision. Thus, as part of contract negotiations, each California Registry participant and verifier will need to sign a form agreeing to this Dispute Resolution policy.

IV.14.20 Key Verification Questions

Verification Deadlines: What is the deadline for completing the verification process?

Emissions should be reported to the California Registry no later than June 30 following the emissions year. Verification should be completed by October 31 following the emissions year. For instance, 2008 emissions should be reported by June 30, 2009 and verified by October 31, 2009.

Costs: What will it cost to have my GHG emissions report verified?

Because verifiers will review GHG emissions reports with more scrutiny every fourth year (barring significant changes to your geographic or organizational boundaries), costs associated with verification are likely to be higher in the first year than in years two or three of the reporting process. In order to obtain an estimate for verification, you will need to convey information about your industrial sector, organization size (annual revenue and number of employees), number of facilities, estimated number and type of direct emissions sources, types of indirect emissions sources (e.g., electricity from a utility or electricity or heat from co-generation), the types of gases you are reporting, and the methodologies you are using to estimate and report your emissions (e.g., CARROT).

You may contact the California Registry for information about the costs associated with verifying your GHG emissions report.

In addition, you may contact California Registry-approved verifiers listed on the California Registry's website at www.climateregistry.org for information about the estimated costs associated with verification.

Batch Verification: What is it? How does it work? How will it affect bidding, contracting, and the overall verification process?

In an effort to minimize transaction costs, eligible California Registry participants may request to participate in batch verification with similar organizations through the California Registry. Eligible participants have relatively simple GHG emission sources and no more than 500 tons of CO_2e from only indirect emissions from electricity consumption at four or fewer sites, direct emissions from stationary combustion at a single site, and/or direct emissions from five or less vehicles. In that situation, bidding, contract negotiations, and the kick-off meeting will take place between the verifier and the California Registry. Standard terms and conditions are expected to apply for all contract elements. The California Registry will initiate the procurement process for batch verification.

Verification and Remediation: What if my GHG emissions report is not verified?

At the completion of the verification process, the verifier will prepare a Verification Report and forward it to the responsible official representing the California Registry participant. (The responsible official includes anyone authorized by the participant to approve the GHG emissions report for submission to the California Registry and will typically be a corporate official or the technical manager of the verification contract.)

If the verifier identifies material discrepancies that prevent a favorable Verification Opinion, those material misstatements should be listed and described in the Verification Report. If possible, the participant may correct those material discrepancies and resubmit the emissions report for verification within a reasonable amount of time. The participant may hire technical assistance to correct material discrepancies but the verifier may not provide such technical assistance as it would create a conflict of interest.

If the participant is unable to correct the material discrepancies, the California Registry will retain the participant's data in the California Registry database for up to two years pending verification. Participants who have submitted a report and undergone verification as part of a "learning by doing" process may wish to retain a pending status for their emissions report for up to two years while the report is enhanced. After that time, the data will be deleted from CARROT. The participant may re-enter the data at a later date with the same conditions.

Verification Report, Verification Opinion, and Verification Activity Log: What are these documents and how are they different?

The Verification Report is a detailed report that a verifier prepares for a participant. The report should describe the scope of the verification process, standards used, emissions sources identified, sampling techniques, and evaluation of the participant's compliance with the General Reporting Protocol, and list material and immaterial discrepancies, if any. The Verification Report is a confidential document between a verifier and participant, and is not shared with the California Registry or the public.

The Verification Opinion is a brief, one-page summary of a verifier's findings that simply states if a participant's emissions report is verifiable or not. The Verification Opinion is submitted to the participant and then to the California Registry. A majority of the contents of the Verification Opinion will be available to the public.

The Verification Activity Log is a form that the verifier must complete that asks them to demonstrate consistency in their professional judgments. The form asks them to respond to a series of yes and no questions, and to provide the dates they have performed verification activities. This information is submitted by the verifier to the California Registry via CARROT, and is not shared with the public.

Confidentiality: Are the results of the verification kept confidential? Are emissions data kept confidential?

The California Registry will make public the Verification Opinion as well as the identity of your verifier, but not your Verification Report. All aggregated entity-level emissions data and metrics reported to the California Registry will be available to the public. However, the California Registry intends to keep confidential all reported emissions, activity data, methodologies, and emissions factors with a higher granularity (at facility, project or source levels). Confidential information will only be accessible to the participant, the California Registry, and the verifier, unless the participant allows others access to such information or wishes to have it available to the public.

General Verification Protocol Revision Policy: Will the General Verification Protocol change over time? How can participants provide feedback to the California Registry?

The California Registry expects to regularly review, revise, update, and augment the General Verification Protocol. The California Registry invites all parties, verifiers, California Registry participants, California State agencies, and the public to provide insights and experiences that will help improve the General Verification Protocol. Anyone with suggestions or concerns is encouraged to contact the California Registry at any time.

Stakeholders will also be able to present suggestions directly to the California Registry's Board of Directors for consideration at their meetings. All suggestions and requests for modifications must be made by utilizing the "Protocol Comment Form" available on the California Registry's website at www.climateregistry.org/protocols.

Appendix A Glossary

Anthropogenic Emissions

GHG emissions that are a direct result of human activities or are the result of natural processes that have been affected by human activities.

Barrel (bbl)

Commonly used to measure quantities of various petroleum products, a volumetric measure for liquids equal to 42 U.S. gallons at 60 degrees Fahrenheit.

Baseline

For the purposes of this Protocol, a datum against which to measure GHG emissions performance or change over time, usually annual emissions in a selected base year.

Base year

The first year in which GHG emissions are reported.

Batch Verification

Simultaneous verification process arranged by the California Registry for multiple participants with simple GHG emissions (typically only indirect emissions from electricity consumption and direct emissions from stationary combustion at a single site and/or direct emissions from a small number of vehicles).

Biogenic Emissions

CO_2 emissions produced from combusting a variety of biofuels, such as biodiesel, ethanol, wood, wood waste and landfill gas.

British Thermal Unit (BTU)

The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Carbon Dioxide (CO_2)

The most common of the six primary GHGs, consisting of a single carbon atom and two oxygen atoms, and providing the reference point for the GWP of other gases. (Thus, the GWP of CO_2 is equal to one.)

CO_2 equivalent (CO_2e)

A measure for comparing carbon dioxide with other GHGs (which generally have a higher global warming potential (GWP)), based on the amount of those other gases multiplied by the appropriate GWP factor; commonly expressed as metric tons of carbon dioxide equivalents ($MTCO_2e$). CO_2e is calculated by multiplying the metric tons of a gas by the appropriate GWP.

Carbon Intensity

The relative amount of carbon emitted per unit of energy or fuels consumed.

Co-Generation

The generation of two forms of energy such as heat and electricity from the same process with the purpose of utilizing or selling both simultaneously.

Datum

A reference or starting point.

De Minimis

For the purposes of this Protocol, the GHG emissions from one or more sources, for one or more gases which, when summed, equal less than 5% of an organization's total emissions.

Direct Emissions

For the purposes of this Protocol, emissions from applicable sources that are owned or controlled by the reporting organization.

Emission Factor

A unique value for determining an amount of a GHG emitted for a given quantity of activity data (e.g., million metric tons of carbon dioxide emitted per barrel of fossil fuel).

Equity Share

According to the calculated share.

Fugitive Emissions

Emissions that are not physically controlled but result from the intentional or unintentional release of GHGs. They commonly arise from the production, processing, transmission, storage and use of fuels or other chemicals, often through joints, seals, packing, gaskets, etc. Examples include HFCs from refrigeration leaks, SF_6 from electrical power distributors, and CH_4 from solid waste landfills.

Global Warming Potential (GWP)

The ratio of radiative forcing that would result from the emission of one kilogram of a GHG to that from the emission of one kilogram of carbon dioxide over a fixed period of time.

Greenhouse Gases (GHGs)

For the purposes of the California Registry, GHGs are the six gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Higher Heating Value (HHV)

The amount of heat released from the complete combustion of a fuel including water vapor produced in the process.

Hydrocarbons

Chemical compounds containing only carbon and hydrogen, including fossil fuels and a variety of major air pollutants.

Hydrofluorocarbons (HFCs)

One of the six primary GHGs primarily used as refrigerants, consists of a class of gases containing hydrogen, fluorine, and carbon, and possessing a range of high and very high GWP values from 120 to 12,000.

Indirect Emissions

Emissions that occur because of a participant's actions, but are produced by sources owned or controlled by another entity.

Intergovernmental Panel on Climate Change (IPCC)

An organization established jointly by the United Nations Environment Programme and the World Meteorological Organization in 1988 to assess information in the scientific and technical literature related to all significant components of the issue of climate change, and providing technical analysis of the science of climate change as well as guidance on the quantification of GHG emissions.

Joule

A measure of energy, representing the energy needed to push with a force of one Newton for one meter.

Kilowatt Hour (kWh)

The electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A Watt is the unit of electrical power equal to one ampere under a pressure of one volt, or 1/746 horsepower.)

Leakage

A situation where emissions shift from one location to another resulting in a direct increase in emissions.

Lower Heating Value (LHV)

The amount of heat released from the complete combustion of a fuel after netting out the heat that is released with the water vapor produced in the process.

Management Control

The ability of an entity to govern the operating policies of another entity or facility so as to obtain benefits from its activities.

Material

Any emission of GHG that is not de minimis in quantity.

Material Discrepancy

With respect to verifying an entity's emissions inventory, a material discrepancy occurs when a difference in reported emissions between an entity and a verifier exceeds 5% of the reported emissions. A difference is immaterial if it is less than 5% of reported emissions.

Member

An entity that is preparing its annual GHG emissions report, but does not have a current verified emissions report with the California Registry.

Methane (CH_4)

One of the six primary GHGs, consisting of a single carbon atom and four hydrogen atoms, possessing a GWP of 21, and produced through the anaerobic decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion.

Metric Ton

Common international measurement for the quantity of GHG emissions, equivalent to about 2,204.6 pounds or 1.1 short tons.

Mobile Combustion

Burning of fuels by transportation devices such as cars, trucks, airplanes, vessels, etc.

Nitrous Oxide (N_2O)

One of the six primary GHGs, consisting of two nitrogen atoms and a single oxygen atom, possessing a GWP of 310, and typically generated as a result of soil cultivation practices, particularly the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.

Perfluorocarbons (PFCs)

One of the six primary GHGs, consists of a class of gases containing carbon and fluorine (represented by the chemical formula CNF(2N+2)), originally introduced as alternatives to ozone depleting substances and typically emitted as by-products of industrial and manufacturing processes, and possessing GWPs ranging from 5,700 to 11,900.

Process Emissions

Emissions from physical or chemical processing rather than from fuel combustion. Examples include CO_2 emissions from cement manufacturing and PFC emissions from aluminum smelting.

Project Baseline

Datum against which to measure GHG emissions performance of a specific emissions reduction project over time, usually annual emissions measured from a base year.

Outsourcing

The contracting out of activities to other businesses.

Significance Threshold

Significance, in the context of the California Registry, is defined as including all sources that are not de minimis. For the purposes of the California Registry, the significance threshold is set at 95%.

Stationary Combustion

Burning of fuels to generate electricity, steam, or heat.

Short Ton

Common measurement for a ton in the U.S. and equivalent to 2,000 pounds or about 0.907 metric tons.

Sulfur Hexafluoride (SF_6)

One of the six primary GHGs, consisting of a single sulfur atom and six fluoride atoms, possessing a very high GWP of 23,900, and primarily used in electrical transmission and distribution systems.

Therm

A measure of one hundred thousand (10^5) Btu.

Verification

For the purposes of this Protocol, the method used to ensure that a given participant's GHG emissions inventory (either the baseline or annual result) has met a minimum quality standard and complied with an appropriate set of California Registry-approved procedures and protocols for submitting emissions inventory information.

Verification Body

For the purposes of this Protocol, an organization or company that is considered California Registry-approved. This applies to currently approved verification bodies, verification bodies approved by the State of California and verification bodies that are accredited to the international standard ISO 14065:2007 to perform GHG verification activities.

Verified Member

A California Registry participant that has a current verified annual emissions report accepted by the California Registry; also known as a *Climate Action Leader*.

Verifier

For the purposes of this Protocol, an individual that is staff or a subcontractor to a California Registry-approved verification body and is qualified to provide verification services for California Registry participants. All verifiers shall complete California Registry training and shall be identified on the designated staff form submitted to the California Registry.

Appendix B Common Conversion Factors

Energy		
1 quadrillion Btu	=	1.0551 x 10^{18} joules
	=	1.0551 exajoules
	=	10^9 MMBtu
1 MMBtu (million Btu)	=	1.0551 x 10^{12} joules
	=	1.0551 x 10^{-6} exajoules
	=	10 Therm
1 joule	=	947.9 x 10^{-21} quadrillion Btu
1 exajoule	=	10^{18} joules
	=	0.9479 quadrillion Btu
1 GJ (gigajoule)	=	947,817 Btu
	=	277.8 kilowatt hours (kWh)
	=	0.2778 Megawatt hours (MWh)
1 Therm	=	10^5 Btu
Mass		
1 short ton (U.S. ton)	=	2,000 pounds (lbs)
	=	0.9072 metric tons
	=	9.072 x 10^4 grams
1 kilogram	=	2.20462 pounds (lbs)
1 metric ton	=	1.1023 short tons
	=	1.1023 tons (U.S.)
	=	2,204.62 pounds (lbs)
	=	1,000 kg
	=	10^{-3} kilotons
	=	10^{-6} megatons
Volume		
1 cubic centimeter	=	3.531 x 10^{-5} cubic feet
1 cubic meter (m^3)	=	35.3115 ft^3 (cubic feet)
	=	1,000 liters
	=	264.2 U.S. gallons
	=	6.29 barrels
	=	1.308 yd^3 (cubic yards)
1 barrel	=	42 gallons
	=	5.6139 ft^3 (cubic feet)
	=	0.15898 m^3
	=	158.98 liters

Area

1 acre	=	0.40468724 hectare (ha)
	=	4,047 m^2
1 hectare (ha)	=	35.3115 ft^3 (cubic feet)
	=	10,000 m^2
	=	2.47 acres

Distance

1 kilometer	=	0.6214 miles

Density

1,000 cubic feet of methane (CH_4)	=	42.28 pounds
	=	1,000 cubic feet carbon dioxide (CO_2)
	=	115.97 pounds
1 metric ton natural gas liquids	=	11.6 barrels
1 metric ton unfinished oils	=	7.46 barrels
1 metric ton alcohol	=	7.94 barrels
1 metric ton liquefied petroleum gas	=	11.6 barrels
1 metric ton aviation gasoline	=	8.9 barrels
1 metric ton naphtha jet fuel	=	8.27 barrels
1 metric ton kerosene jet fuel	=	7.93 barrels
1 metric ton motor gasoline	=	8.53 barrels
1 metric ton kerosene	=	7.73 barrels
1 metric ton naphtha	=	8.22 barrels
1 metric ton distillate	=	7.46 barrels
1 metric ton residual oil	=	6.66 barrels
1 metric ton lubricants	=	7.06 barrels
1 metric ton bitumen	=	6.06 barrels
1 metric ton waxes	=	7.87 barrels
1 metric ton petroleum coke	=	5.51 barrels
1 metric ton petrochemical feedstocks	=	7.46 barrels
1 metric ton special naphtha	=	8.53 barrels
1 metric ton miscellaneous products	=	8.00 barrels

Metric Prefixes

Abbreviation	Prefix	Multiple
k	kilo-	10^3 or 1,000
M	mega-	10^6 or 1,000,000
G	giga-	10^9 or 1,000,000,000
T	tera-	10^{12} or 1,000,000,000,000
P	peta-	10^{15} or 1,000,000,000,000,000

Appendix C Calculation References

Converting to CO_2 Equivalent

To incorporate and evaluate non-CO_2 gases in your GHG emissions inventory, the mass estimates of these gases will need to be converted to CO_2 equivalent (CO_2e). To do this, multiply the emissions in units of mass by the GHGs global warming potential (GWP).

Global warming potentials were developed by the Intergovernmental Panel on Climate Change (IPCC) to quantify the globally averaged relative radiative forcing effects of a given GHG, using carbon dioxide as the reference gas. In 1996, the IPCC published a set of GWPs for the most commonly measured greenhouse gases in its Second Assessment Report (SAR). In 2001, the IPCC published its Third Assessment Report (TAR), which adjusted the GWPs to reflect new information on atmospheric lifetimes and an improved calculation of the radiative forcing of carbon dioxide. However, SAR GWPs are still used by international convention and the U.S. to maintain the value of the carbon dioxide "currency". To maintain consistency with international practice, the California Registry requires participants to use GWPs from the SAR for calculating their emissions inventory.

Table C.1 lists the 100-year GWPs from SAR and TAR. The equation above provides the basic calculation required to determine CO_2e from the total mass of a given GHG using the GWPs published by the IPCC.

Converting Mass Estimates to Carbon Dioxide Equivalent

Metric Tons of CO_2e = Metric Tons of GHG x GWP

Table C.1 Comparison of GWPs from the IPCC's Second and Third Assessment Reports

Greenhouse Gas	GWP (SAR, 1996)	GWP (TAR, 2001)
CO_2	1	1
CH_4	21	23
N_2O	310	296
HFC-23	11,700	12,000
HFC-32	650	550
HFC-125	2,800	3,400
HFC-134a	1,300	1,300
HFC-143a	3,800	4,300
HFC-152a	140	120
HFC-227ea	2,900	3,500
HFC-236fa	6,300	9,400
HFC-4310mee	1,300	1,500
CF_4	6,500	5,700
C_2F_6	9,200	11,900
C_3F_8	7,000	8,600
C_4F_{10}	7,000	8,600
C_6F_{14}	7,400	9,000
SF_6	23,900	22,000

Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003 (April 2005).

Emission Factors for Electricity Use

Table C.2 Carbon Dioxide, Methane and Nitrous Oxide Electricity Emission Factors by eGRID Subregion

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 (lbs/MWh)	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
AKGD	ASCC Alaska Grid	1,232.36	0.0256	0.0065
AKMS	ASCC Miscellaneous	498.86	0.0208	0.0041
AZNM	WECC Southwest	1,311.05	0.0175	0.0179
CAMX	WECC California	724.12	0.0302	0.0081
ERCT	ERCOT All	1,324.35	0.0187	0.0151
FRCC	FRCC All	1,318.57	0.0459	0.0169
HIMS	HICC Miscellaneous	1,514.92	0.3147	0.0469
HIOA	HICC Oahu	1,811.98	0.1095	0.0236
MROE	MRO East	1,834.72	0.0276	0.0304
MROW	MRO West	1,821.84	0.0280	0.0307
NEWE	NPCC New England	927.68	0.0865	0.0170
NWPP	WECC Northwest	902.24	0.0191	0.0149
NYCW	NPCC NYC/Westchester	815.45	0.0360	0.0055
NYLI	NPCC Long Island	1,536.80	0.1154	0.0181
NYUP	NPCC Upstate NY	720.80	0.0248	0.0112
RFCE	RFC East	1,139.07	0.0303	0.0187
RFCM	RFC Michigan	1,563.28	0.0339	0.0272
RFCW	RFC West	1,537.82	0.0182	0.0257
RMPA	WECC Rockies	1,883.08	0.0229	0.0288
SPNO	SPP North	1,960.94	0.0238	0.0321
SPSO	SPP South	1,658.14	0.0250	0.0226
SRMV	SERC Mississippi Valley	1,019.74	0.0243	0.0117
SRMW	SERC Midwest	1,830.51	0.0212	0.0305
SRSO	SERC South	1,489.54	0.0263	0.0255
SRTV	SERC Tennessee Valley	1,510.44	0.0201	0.0256
SRVC	SERC Virginia/Carolina	1,134.88	0.0238	0.0198

Source: eGRID2007 Version 1.1, December 2008 (Year 2005 data).
Note: Reporters calculating historical data for calendar years 1990-2007 should use the electricity emission factors in Appendix E.

Emission Factors for Mobile Combustion

Table C.3 Carbon Dioxide Emission Factors for Transport Fuels

Fuel	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor
	kg C/MMBtu	MMBtu/barrel		kg CO_2/gallon
Aviation Gasoline	18.87	5.048	1.00	8.32
Biodiesel (B100)* +	NA	NA	1.00	9.46
Crude Oil	20.33	5.80	1.00	10.29
Diesel	19.95	5.825	1.00	10.15
Ethanol (E100)* +	17.99	3.539	1.00	5.56
Jet Fuel (Jet A or A-1)	19.33	5.670	1.00	9.57
Kerosene	19.72	5.670	1.00	9.76
Liquefied Natural Gas (LNG)+	NA	NA	1.00	4.46
Liquefied Petroleum Gas (LPG)+	17.23	3.849	1.00	5.79
Ethane	16.25	2.916	1.00	4.14
Isobutane	17.75	4.162	1.00	6.45
n-Butane	17.72	4.328	1.00	6.70
Propane	17.20	3.824	1.00	5.74
Methanol	NA	NA	1.00	4.10
Motor Gasoline	19.33	5.218	1.00	8.81
Residual Fuel Oil (#5, 6)	21.49	6.287	1.00	11.80
	kg C/MMBtu	Btu/standard cubic foot		kg CO_2/therm
Compressed Natural Gas (CNG)+	14.47	1027	1.00	5.31

* CO_2 emissions from biodiesel and ethanol combustion are considered biogenic and should not be reported as a direct mobile combustion emission (see Chapter 7). These biogenic CO_2 emissions may be reported optionally.

Note: CO_2 emission factors are calculated using the molar mass ratio of carbon dioxide to carbon (CO_2/C) of 44/12. Heat content factors are based on higher heating values (HHV). NA = data not available. A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006).

Source: U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 2.1, Tables A-31, A-34, A-36, A-39, except those marked + (from EPA Climate Leaders Mobile Combustion Guidance). Methanol emission factor is calculated from the properties of the pure compounds.

Table C.4 Methane and Nitrous Oxide Emission Factors for Highway Vehicles by Model Year

Vehicle Types/Model Years	N_2O (g/mile)	CH_4 (g/mile)
Gasoline Passenger Cars		
Model Years 1984-1993	0.0647	0.0704
Model Year 1994	0.0560	0.0531
Model Year 1995	0.0473	0.0358
Model Year 1996	0.0426	0.0272
Model Year 1997	0.0422	0.0268
Model Year 1998	0.0393	0.0249
Model Year 1999	0.0337	0.0216
Model Year 2000	0.0273	0.0178
Model Year 2001	0.0158	0.0110
Model Year 2002	0.0153	0.0107
Model Year 2003	0.0135	0.0114
Model Year 2004	0.0083	0.0145
Model Year 2005 - Present	0.0079	0.0147
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
Model Years 1987-1993	0.1035	0.0813
Model Year 1994	0.0982	0.0646
Model Year 1995	0.0908	0.0517
Model Year 1996	0.0871	0.0452
Model Year 1997	0.0871	0.0452
Model Year 1998	0.0728	0.0391
Model Year 1999	0.0564	0.0321
Model Year 2000	0.0621	0.0346
Model Year 2001	0.0164	0.0151
Model Year 2002	0.0228	0.0178
Model Year 2003	0.0114	0.0155
Model Year 2004	0.0132	0.0152
Model Year 2005 - Present	0.0101	0.0157

Table C.4 Methane and Nitrous Oxide Emission Factors for Highway Vehicles by Model Year (continued)

Vehicle Types/Model Years	N_2O (g/mile)	CH_4 (g/mile)
Gasoline Heavy-Duty Vehicles		
Model Years 1985-1986	0.0515	0.4090
Model Year 1987	0.0849	0.3675
Model Years 1988-1989	0.0933	0.3492
Model Years 1990-1995	0.1142	0.3246
Model Year 1996	0.1680	0.1278
Model Year 1997	0.1726	0.0924
Model Year 1998	0.1693	0.0641
Model Year 1999	0.1435	0.0578
Model Year 2000	0.1092	0.0493
Model Year 2001	0.1235	0.0528
Model Year 2002	0.1307	0.0546
Model Year 2003	0.1240	0.0533
Model Year 2004	0.0285	0.0341
Model Year 2005 - Present	0.0177	0.0326
Diesel Passenger Cars		
Model Years 1960-1982	0.0012	0.0006
Model Years 1983 - Present	0.0010	0.0005
Diesel Light Trucks		
Model Years 1960-1982	0.0017	0.0011
Model Years 1983-1995	0.0014	0.0009
Model Years 1996 - Present	0.0015	0.0010
Diesel Heavy-Duty Vehicles		
All Model Years	0.0048	0.0051

Source: Gasoline vehicle factors from EPA Climate Leaders, Mobile Combustion Guidance, (2008) based on U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007). Diesel vehicle factors based on U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-98.

Table C.5 Methane and Nitrous Oxide Emission Factors for Alternative Fuel Vehicles

Vehicle Type	N_2O (g/mile)	CH_4 (g/mile)
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Heavy Duty Vehicles		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Biodiesel*	0.050	0.060
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197

Source: U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-100, except biodiesel.

* Biodiesel emission factor derived from California Energy Commission, Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (Draft: December 2001), Table 2-20.

Table C.6 Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles

Vehicle Type/Fuel Type	N_2O (g/gallon)	CH_4 (g/gallon)
Ships & Boats		
Residual Fuel Oil	0.30	0.86
Diesel Fuel	0.26	0.74
Gasoline	0.22	0.64
Locomotives		
Diesel Fuel	0.26	0.80
Agricultural Equipment		
Gasoline	0.22	1.26
Diesel Fuel	0.26	1.44
Construction		
Gasoline	0.22	0.50
Diesel Fuel	0.26	0.58
Other Non-Highway		
Snowmobiles (Gasoline)	0.22	0.50
Other Recreational (Gasoline)	0.22	0.50
Other Small Utility (Gasoline)	0.22	0.50
Other Large Utility (Gasoline)	0.22	0.50
Other Large Utility (Diesel)	0.26	0.58
Aircraft		
Jet Fuel	0.31	0.27
Aviation Gasoline	0.11	7.04
All Non-Highway/Construction Vehicles		
Butane*	0.41	0.09
Propane*	0.41	0.09

Source: U.S. EPA, Climate Leaders, Mobile Combustion Guidance (2008) based on U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.2, Table A-101, except butane and propane.

* Butane and propane emission factors based on stationary combustion emission factors for these fuels from U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000 (2002).

Emission Factors for Stationary Combustion

Table C.7 Carbon Dioxide Emission Factors for Stationary Combustion

Fuel Type	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor	CO_2 Emission Factor
Coal and Coke	kg C/ MMBtu	MMBtu/ short ton		kg CO_2/ metric ton	kg CO_2/MMBtu
Anthracite	28.26	25.09	1.00	2,865.77	103.62
Bituminous	25.49	24.93	1.00	2,568.39	93.46
Sub-bituminous	26.48	17.25	1.00	1,846.19	97.09
Lignite	26.30	14.21	1.00	1,510.49	96.43
Residential/Commercial	26.00	22.05	1.00	2,317.13	95.33
Industrial Coking	25.56	26.27	1.00	2,713.87	93.72
Other Industrial	25.63	22.05	1.00	2,284.16	93.98
Electric Power	25.76	19.95	1.00	2,077.10	94.45
Coke	31.00	24.80	1.00	3,107.29	113.67
Petroleum Products (Gaseous)	kg C/ MMBtu	Btu/ standard cubic foot		kg CO_2/ standard cubic foot	kg CO_2/MMBtu
Natural Gas (weighted U.S. average)	14.47	1,029	1.00	0.0546	53.06
Acetylene (C_2H_2)	19.48	1,476	1.00	.1043	71.42
Petroleum Products (Liquid)	kg C/ MMBtu	MMBtu/ barrel		kg CO_2/gallon	kg CO_2/MMBtu
Asphalt & Road Oil	20.62	6.636	1.00	11.95	75.61
Aviation Gasoline	18.87	5.048	1.00	8.32	69.19
Distillate Fuel Oil (#1,2&4)	19.95	5.825	1.00	10.15	73.15
Jet Fuel	19.33	5.670	1.00	9.57	70.88
Kerosene	19.72	5.670	1.00	9.76	72.31
LPG (average for fuel use)	17.23	3.849	1.00	5.79	63.16
Propane	17.20	3.824	1.00	5.74	63.07
Ethane	16.25	2.916	1.00	4.14	59.58
Isobutane	17.75	4.162	1.00	6.45	65.08
n-Butane	17.72	4.328	1.00	6.70	64.97
Lubricants	20.24	6.065	1.00	10.72	74.21
Motor Gasoline	19.33	5.218	1.00	8.81	70.88
Residual Fuel Oil (#5 & 6)	21.49	6.287	1.00	11.80	78.80
Crude Oil	20.33	5.800	1.00	10.29	74.54
Naphtha (<401 deg. F)	18.14	5.248	1.00	8.31	66.51
Natural Gasoline	18.24	4.620	1.00	7.36	66.88
Other Oil (>401 deg. F)	19.95	5.825	1.00	10.15	73.15

Table C.7 Carbon Dioxide Emission Factors for Stationary Combustion (continued)

Fuel Type	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor	CO_2 Emission Factor
Petroleum Products (Liquid)	**kg C/ MMBtu**	**MMBtu/ barrel**		**kg CO_2/gallon**	**kg CO_2/MMBtu**
Pentanes Plus	18.24	4.620	1.00	7.36	66.88
Petrochemical Feedstocks	19.37	5.428	1.00	9.18	71.02
Petroleum Coke	27.85	6.024	1.00	14.65	102.12
Still Gas	17.51	6.000	1.00	9.17	64.20
Special Naphtha	19.86	5.248	1.00	9.10	72.82
Unfinished Oils	20.33	5.825	1.00	10.34	74.54
Waxes	19.81	5.537	1.00	9.58	72.64
Non-Fossil Fuels (Solid)	**kg C/ MMBtu**	**MMBtu/ short ton**		**kg CO_2/ metric ton**	**kg CO_2/MMBtu**
Wood and Wood Waste (12% moisture content)*	25.60	15.38	1.00	1,591.35	93.87
Non-Fossil Fuels (Gas)	**kg C/ MMBtu**	**Btu/ standard cubic foot**		**kg CO_2/ standard cubic foot**	**kg CO_2/MMBtu**
Biogas*	14.20	502.50	1.00	varies	52.07

*The CO_2 emissions from burning wood, wood waste and biogas are considered biogenic and should not be included as a direct stationary emission in your inventory. You may report these emissions optionally. For biogas, please note that the values above are for the methane fraction of the biogas only. To report all of the biogenic CO_2 emissions associated with biogas, you would also need to report the CO_2 fraction of the biogas.

Note: CO_2 emission factors are calculated using the molar mass ratio of carbon dioxide to carbon (CO_2/C) of 44/12. Heat content factors are based on higher heating values (HHV). A fraction oxidized value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), Guidelines for National Greenhouse Gas Inventories (2006).

Source: U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: Heat Content factors for Coal (by sector), Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, Annual Energy Review 2006 (2007), Tables A-1 and A-5) and Carbon Content and Heat Content factors for Coke and LPG and all factors for Wood and Wood Waste and Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Tables B-1 and B-2). Acetylene factor derived from API Compendium (February 2004), Exhibit 4.1(a) and HHV from GPSA.

Table C.8 Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Fuel Type and Sector

Fuel Type/End-Use Sector	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Coal		
Residential	0.316	0.0016
Commercial/Institutional	0.011	0.0016
Manufacturing/Construction	0.011	0.0016
Electric Power	0.001	0.0016
Petroleum Products		
Residential	0.011	0.0006
Commercial/Institutional	0.011	0.0006
Manufacturing/Construction	0.003	0.0006
Electric Power	0.003	0.0006
Natural Gas		
Residential	0.005	0.0001
Commercial/Institutional	0.005	0.0001
Manufacturing/Construction	0.001	0.0001
Electric Power	0.001	0.0001
Wood		
Residential	0.316	0.0042
Commercial/Institutional	0.316	0.0042
Manufacturing/Construction	0.032	0.0042
Electric Power	0.032	0.0042
Pulping Liquors		
Manufacturing	0.0025	0.0020

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.1.

Table C.9 Methane and Nitrous Oxide Emission Factors for Stationary Combustion for Petroleum Products by Fuel Type and Sector

Fuel Type/End-Use Sector	CH_4 (kg/gallon)	N_2O (kg/gallon)
Residential		
Distillate Fuel	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel	0.0016	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Commercial/Institutional		
Distillate Fuel	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel	0.0016	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Manufacturing/Construction		
Distillate Fuel	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel	0.0004	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001
Electric Power		
Distillate Fuel	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel	0.0004	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001

Note: All emission factors were converted to kg/gallon using the petroleum products emission factors from Table C.8 and the heat content in MMBtu/barrel from Table C.7 specific to each petroleum fuel: heat content of fuel type (MMBtu/barrel) / 42 (barrels/gallon) x petroleum emission factor (kg/MMBtu) = petroleum emission factor (kg/gallon).

Source: Derived from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.1.

Appendix D Electricity Emission Factors for Non-U.S. Countries

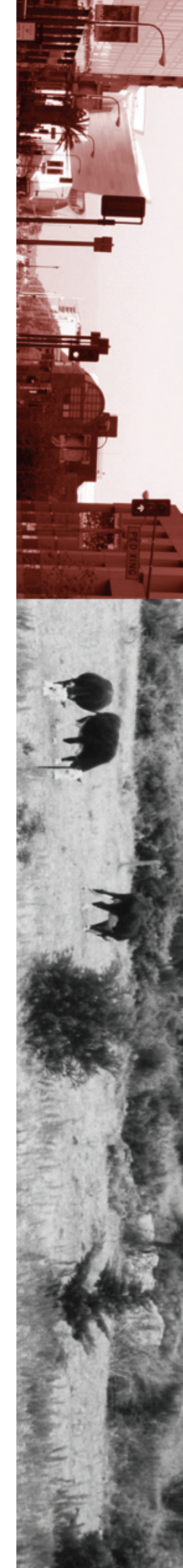


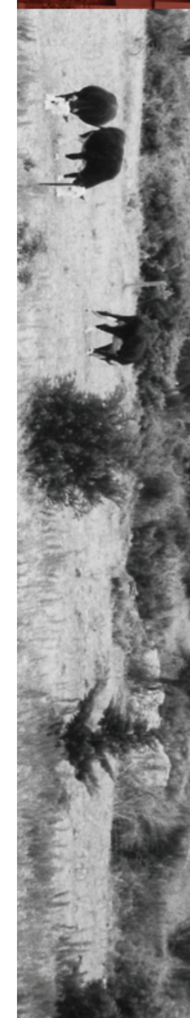
Table D.1 Country-Specific Carbon Dioxide Electricity Emission Factors (lbs CO_2/MWh)*

Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Albania	…	…	113	177	188	82	52	45	39	85	108	133	128	67	71	76
Algeria	…	…	1,458	1,438	1,502	1,541	1,479	1,503	1,556	1,528	1,512	1,515	1,542	1,543	1,543	1,479
Angola	…	…	398	288	400	391	418	537	446	753	843	841	781	822	743	756
Argentina	…	…	829	745	725	601	810	719	756	803	746	589	569	605	698	676
Armenia	…	…	881	241	279	472	508	581	569	495	520	536	338	326	264	305
Australia	1,788	1,795	1,810	1,777	1,724	1,710	1,815	1,908	1,940	1,923	1,906	1,863	1,967	1,922	1,860	1,925
Austria	539	555	460	427	456	472	506	502	458	430	404	428	429	520	507	496
Azerbaijan	…	…	…	1,889	1,062	1,111	1,151	1,175	1,196	1,359	1,435	1,240	1,082	1,156	1,129	1,113
Bahrain	…	…	2,325	1,962	1,932	1,797	1,789	1,688	1,811	1,877	1,913	1,852	1,841	1,947	1,943	1,962
Bangladesh	…	…	1,232	1,307	1,286	1,325	1,250	1,287	1,297	1,306	1,225	1,328	1,331	1,266	1,383	1,228
Belarus	…	…	…	734	753	714	677	683	670	655	676	655	661	653	669	659
Belgium	768	755	731	763	806	790	749	686	695	614	628	600	587	603	592	591
Benin	…	…	2,496	2,669	1,457	2,096	1,616	1,755	1,496	1,453	1,327	2,106	2,095	1,658	1,632	1,565
Bolivia	…	…	832	784	972	1,064	854	938	994	685	657	1,121	1,036	1,005	1,184	1,061
Bosnia-Herzegovina	…	…	2,040	3,257	386	422	570	1,335	1,731	1,535	1,547	1,576	1,369	1,420	1,325	1,364
Botswana	…	…	3,462	3,441	3,595	3,960	4,080	4,320	2,746	3,466	4,128	2,900	2,910	2,904	3,826	4,073
Brazil	…	…	134	122	113	122	126	137	137	182	194	229	189	175	188	186
Brunei Darussalam	…	…	2,016	2,056	2,165	1,941	1,884	1,886	1,908	1,832	1,753	1,761	1,804	1,789	1,788	1,739
Bulgaria	…	…	1,049	1,064	1,007	947	922	1,047	1,060	982	950	1,022	954	1,037	1,037	988
Cambodia	…	…	…	…	…	4,004	3,698	5,516	4,576	3,891	3,966	4,278	4,345	4,147	2,869	2,659
Cameroon	…	…	26	20	23	23	22	22	33	25	22	36	59	68	61	86
Canada	430	413	432	386	379	389	376	418	476	456	478	498	470	496	455	438
Chile	…	…	404	407	554	575	767	848	921	1,011	731	574	578	616	752	788
China	…	…	1,751	1,750	1,693	1,770	1,809	1,773	1,815	1,759	1,686	1,631	1,650	1,711	1,776	1,737
Colombia	…	…	590	502	408	451	383	457	470	390	442	421	413	389	360	360
Congo	…	…	16	19	22	20	15	15	20	252	0	0	0	0	0	0
Democratic Republic of Congo	…	…	7	6	9	8	8	10	10	9	8	8	8	8	7	7
Costa Rica	…	…	309	217	379	344	193	74	150	46	18	31	34	43	38	59
Côte d'Ivoire	…	…	542	632	706	607	750	927	1,141	912	837	868	902	847	890	1,142
Croatia	…	…	717	723	551	601	559	658	713	668	660	683	780	831	656	686
Cuba	…	…	2,020	2,324	2,430	2,506	2,437	2,445	2,579	2,275	2,257	2,186	2,404	2,493	2,235	2,177

* CO_2 emissions from fossil fuels consumed for electricity, combined heat and power and main activity heat plants divided by the output of electricity and heat generated from fossil fuels, nuclear, hydro (excluding pumped storage), geothermal, solar, etc.
Source: International Energy Agency Data Services, 2007. "CO_2 emissions from Fuel Combustion (2007 Edition)".

Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Cyprus	…	…	1,833	1,835	1,843	1,822	1,845	1,864	1,868	1,898	1,856	1,722	1,675	1,846	1,712	1,747
Czech Republic	1,321	1,301	1,293	1,284	1,291	1,289	1,282	1,238	1,255	1,233	1,251	1,235	1,204	1,106	1,110	1,137
Denmark	1,050	1,116	1,035	1,007	1,036	948	1,029	929	859	801	748	740	732	787	679	625
Dominican Republic	…	…	1,657	1,597	1,859	1,931	1,641	1,715	1,831	1,873	1,675	1,451	1,618	1,420	1,292	1,265
Ecuador	…	…	612	429	380	692	501	650	634	521	475	600	620	658	666	814
Egypt	…	…	1,168	1,109	1,028	977	954	975	1,031	1,002	908	840	963	953	1,043	1,039
El Salvador	…	…	555	649	838	888	566	825	813	602	634	667	683	654	606	581
Eritrea	…	…	3,369	3,078	3,311	3,227	2,932	2,204	1,516	1,544	1,573	1,652	1,452	1,529	1,592	1,535
Estonia	…	…	1,430	1,367	1,364	1,519	1,497	1,498	1,586	1,558	1,537	1,511	1,482	1,595	1,545	1,466
Ethiopia	…	…	141	127	97	92	87	56	55	21	25	21	17	12	14	15
Finland	508	518	457	512	592	551	639	590	468	467	465	528	558	646	561	427
France	242	275	219	152	154	170	172	159	215	190	182	156	168	177	172	200
Gabon	…	…	627	659	461	563	695	695	758	718	718	600	621	675	709	812
Georgia	…	…	809	704	603	1,076	366	336	357	340	426	293	114	118	172	197
Germany	1,260	1,287	1,219	1,212	1,208	1,174	1,157	1,141	1,121	1,090	1,093	1,116	1,143	966	960	770
Ghana	…	…	0	7	8	6	1	9	510	412	173	285	467	658	184	449
Gibraltar	…	…	1,714	1,713	1,665	1,697	1,666	1,712	1,697	1,697	1,683	1,670	1,684	1,671	1,697	1,638
Greece	2,185	2,074	2,113	2,058	1,949	1,923	1,826	1,916	1,896	1,811	1,794	1,835	1,797	1,706	1,713	1,712
Guatemala	…	…	650	619	651	674	567	527	991	745	864	928	1,067	890	956	846
Haiti	…	…	685	475	199	722	877	1,252	837	637	762	749	881	705	663	678
Honduras	…	…	88	139	303	721	519	586	839	574	618	726	621	776	993	905
Hong Kong, China	…	…	1,806	1,897	1,920	1,879	1,829	1,596	1,632	1,576	1,567	1,585	1,596	1,750	1,829	1,785
Hungary	1,035	1,015	1,070	1,011	974	983	955	951	942	914	908	870	863	928	859	747
Iceland	1	1	1	2	2	4	3	2	6	8	1	1	1	1	1	1
India	…	…	1,960	2,009	1,931	2,041	2,140	2,078	2,031	2,026	2,069	2,059	2,026	1,991	2,077	2,080
Indonesia	…	…	1,409	1,667	1,414	1,283	1,407	1,489	1,434	1,491	1,417	1,630	1,573	1,709	1,654	1,699
Islamic Republic of Iran	…	…	1,236	1,289	1,301	1,334	1,317	1,306	1,240	1,284	1,253	1,273	1,234	1,176	1,174	1,177
Iraq	…	…	1,305	1,372	1,594	1,540	1,540	1,528	1,495	1,494	1,612	1,792	1,656	1,735	1,549	1,545
Ireland	1,653	1,661	1,674	1,624	1,608	1,607	1,605	1,586	1,577	1,538	1,409	1,488	1,405	1,317	1,260	1,288
Israel	…	…	1,809	1,813	1,810	1,811	1,824	1,812	1,688	1,692	1,678	1,704	1,814	1,802	1,780	1,692
Italy	1,265	1,210	1,181	1,158	1,139	1,205	1,158	1,136	1,138	1,098	1,111	1,070	1,122	1,157	905	894
Jamaica	…	…	1,969	2,734	1,844	1,958	1,825	1,825	1,832	1,814	1,810	1,815	1,770	1,751	1,731	1,573
Japan	949	928	941	901	939	900	894	862	836	871	879	881	925	973	937	945
Jordan	…	…	1,974	1,896	1,833	1,838	1,787	1,764	1,779	1,648	1,562	1,548	1,633	1,500	1,505	1,455
Kazakhstan	…	…	2,746	2,691	3,255	2,414	2,476	2,298	2,495	2,461	2,680	2,232	2,597	2,628	2,599	2,506
Kenya	…	…	149	159	180	160	198	229	622	907	1,239	864	597	441	617	676
Dem. People's Republic of Korea	…	…	1,194	1,111	1,117	1,059	1,146	1,228	1,100	1,216	1,285	1,282	1,250	1,193	1,163	1,149

Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Korea	1,129	1,213	1,274	1,233	1,197	1,172	1,164	1,212	1,090	1,056	1,105	1,106	937	982	979	922
Kuwait	…	…	1,421	1,339	1,367	1,407	1,406	1,428	1,432	1,484	1,519	1,478	1,376	1,462	1,661	1,780
Kyrgyzstan	…	…	345	254	180	279	286	303	271	229	234	224	233	207	198	180
Latvia	…	…	609	593	552	525	579	481	435	478	441	418	415	403	367	357
Lebanon	…	…	1,440	1,551	1,472	1,442	1,557	1,521	1,727	1,796	1,616	1,656	1,591	1,562	1,244	1,471
Libya	…	…	1,623	1,600	1,935	2,494	2,361	2,339	2,358	2,328	2,254	2,231	2,140	2,157	1,959	1,983
Lithuania	…	…	410	410	474	381	382	365	380	389	348	317	264	248	243	286
Luxembourg	5,706	5,446	5,476	5,433	4,646	2,954	2,630	1,786	549	568	562	529	725	728	736	723
FYR of Macedonia	…	…	1,828	1,794	1,792	1,850	1,762	1,607	1,656	1,511	1,501	1,715	1,593	1,466	1,497	1,422
Malaysia	…	…	1,374	1,332	1,226	1,227	1,233	1,028	1,189	1,163	1,139	1,192	1,303	1,158	1,171	1,228
Malta	…	…	2,256	3,068	2,566	2,120	2,158	2,076	2,065	2,003	1,913	2,267	1,807	1,794	1,988	1,966
Mexico	1,181	1,179	1,123	1,124	1,237	1,117	1,116	1,151	1,260	1,237	1,248	1,253	1,230	1,234	1,152	1,136
Republic of Moldova	…	…	1,561	1,355	1,275	1,134	1,565	1,610	1,520	1,398	1,639	1,704	1,642	1,666	1,131	1,137
Mongolia	…	…	1,413	1,567	1,363	1,344	1,256	1,165	1,313	1,234	1,293	1,290	1,352	1,220	1,160	1,176
Morocco	…	…	1,821	1,968	1,860	1,915	1,555	1,520	1,608	1,672	1,697	1,684	1,686	1,623	1,651	1,714
Mozambique	…	…	471	330	144	141	121	64	6	6	10	9	7	7	7	3
Myanmar	…	…	971	1,005	1,066	1,120	1,271	1,156	1,324	1,262	1,008	894	829	938	914	804
Namibia	…	…	60	395	573	82	106	125	99	66	46	65	61	59	60	58
Nepal	…	…	110	129	156	56	55	160	162	76	27	16	4	3	3	3
Netherlands	1,328	1,287	1,259	1,267	1,186	1,167	1,104	1,101	1,035	1,031	985	1,019	1,011	1,030	970	852
Netherlands Antilles	…	…	1,583	1,583	1,587	1,581	1,584	1,578	1,582	1,585	1,580	1,581	1,582	1,580	1,582	1,583
New Zealand	282	287	384	306	255	246	307	470	472	524	508	608	544	639	531	607
Nicaragua	…	…	974	874	988	1,067	1,097	1,184	1,394	1,334	1,344	1,351	1,240	1,229	1,229	1,188
Nigeria	…	…	801	865	699	644	669	700	745	771	896	750	781	750	881	888
Norway	8	10	9	9	11	10	14	12	12	13	9	13	12	18	15	12
Oman	…	…	1,884	1,871	1,875	1,831	1,732	1,670	1,655	1,784	1,754	1,801	1,829	1,882	1,952	1,884
Pakistan	…	…	867	847	862	893	976	1,000	907	1,031	1,057	1,020	976	816	875	837
Panama	…	…	813	654	663	699	499	617	984	494	509	881	596	785	586	610
Paraguay	…	…	1	1	0	5	1	1	1	1	0	0	0	0	0	0
Peru	…	…	475	393	345	411	449	464	430	377	334	265	316	326	454	436
Philippines	…	…	1,066	1,056	1,144	1,121	1,133	1,256	1,304	1,104	1,098	1,168	1,063	1,014	1,007	1,092
Poland	1,447	1,434	1,439	1,412	1,418	1,489	1,465	1,470	1,465	1,466	1,481	1,456	1,460	1,460	1,466	1,453
Portugal	1,140	1,152	1,371	1,204	1,096	1,256	946	1,029	1,023	1,189	1,058	976	1,130	912	997	1,098
Qatar	…	…	2,235	2,293	2,381	2,493	2,316	2,237	1,907	1,815	1,700	1,722	1,723	1,718	1,431	1,362
Romania	…	…	903	848	1,006	971	980	849	775	793	872	909	909	995	922	869
Russia	…	…	680	642	653	644	754	724	720	721	707	709	720	726	716	745
Saudi Arabia	…	…	1,836	1,847	1,798	1,797	1,768	1,783	1,796	1,789	1,785	1,716	1,656	1,630	1,674	1,648



Country	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Senegal	…	…	2,009	2,079	2,054	1,941	1,889	1,935	1,936	2,002	1,724	1,762	1,423	1,147	1,224	1,398
Serbia and Montenegro	…	…	1,645	1,671	1,539	1,843	1,762	1,799	1,770	1,498	1,653	1,567	1,629	1,691	1,613	1,649
Singapore	…	…	1,854	2,214	2,153	2,069	1,940	1,696	1,707	1,446	1,463	1,399	1,312	1,265	1,226	1,199
Slovak Republic	834	857	794	909	795	815	800	835	774	769	588	548	494	563	545	512
Slovenia	…	…	807	823	737	743	700	853	868	809	730	752	820	810	742	724
South Africa	…	…	1,886	1,941	1,904	1,936	1,897	1,917	2,045	1,961	1,969	1,827	1,807	1,863	1,908	1,870
Spain	943	934	1,062	924	918	1,007	791	864	839	981	947	845	964	840	843	869
Sri Lanka	…	…	420	163	141	112	511	579	450	504	942	896	958	833	945	877
Sudan	…	…	662	1,139	779	1,026	1,065	1,127	1,027	944	1,175	1,176	1,393	1,639	1,826	1,870
Sweden	106	128	112	115	123	110	162	111	120	106	93	95	115	131	113	98
Switzerland	48	54	61	46	44	48	56	50	61	48	49	47	48	50	52	58
Syria	…	…	1,205	1,236	1,282	1,291	1,299	1,303	1,314	1,319	1,249	1,231	1,221	1,240	1,227	1,295
Taiwan	…	…	1,080	1,115	1,110	1,134	1,149	1,214	1,234	1,278	1,331	1,358	1,335	1,395	1,384	1,393
Tajikistan	…	…	193	144	87	110	135	101	99	91	91	91	60	60	62	60
United Republic of Tanzania	…	…	301	353	490	627	423	859	93	278	425	154	125	112	133	1,337
Thailand	…	…	1,425	1,389	1,374	1,336	1,379	1,397	1,341	1,314	1,244	1,240	1,187	1,164	1,186	1,171
Togo	…	…	545	485	936	408	471	827	1,001	602	790	2,411	478	286	1,099	1,045
Trinidad and Tobago	…	…	1,608	1,668	1,572	1,567	1,518	1,495	1,564	1,560	1,524	1,529	1,702	1,612	1,674	1,563
Tunisia	…	…	1,511	1,492	1,420	1,296	1,328	1,341	1,341	1,318	1,266	1,288	1,243	1,222	1,173	1,062
Turkey	1,287	1,308	1,309	1,156	1,263	1,174	1,187	1,214	1,231	1,272	1,159	1,214	1,055	988	941	954
Turkmenistan	…	…	…	…	…	…	…	1,390	1,345	1,743	1,753	1,753	1,753	1,753	1,753	1,753
Ukraine	…	…	809	846	782	803	730	708	726	742	759	722	711	835	689	693
United Arab Emirates	…	…	1,639	1,639	1,639	1,626	1,632	1,652	1,566	1,560	1,606	1,646	1,695	1,771	2,013	1,860
United Kingdom	1,497	1,461	1,426	1,259	1,194	1,206	1,156	1,067	1,057	956	990	1,049	1,017	1,057	1,072	1,042
Uruguay	…	…	196	148	26	117	229	154	73	413	125	6	9	4	332	227
Uzbekistan	…	…	1,187	1,208	1,083	956	982	1,016	1,070	1,067	1,012	1,030	1,048	1,002	976	977
Venezuela	…	…	500	533	489	483	438	490	523	480	463	622	612	540	541	497
Vietnam	…	…	668	558	644	648	703	900	1,031	874	927	865	934	826	898	894
Yemen	…	…	1,953	1,700	2,020	2,084	2,122	2,051	2,194	2,030	2,049	2,050	2,026	1,949	1,939	1,864
Zambia	…	…	29	24	19	16	16	22	22	15	15	15	15	15	15	15
Zimbabwe	…	…	2,270	2,283	2,407	2,028	1,938	1,735	2,002	1,790	1,631	1,870	1,581	1,136	1,261	1,262

Appendix E Electricity Emission Factors for Historical Reporting Purposes

Tables E.1 and E.2 provide carbon dioxide electricity emission factors by eGRID subregion for use in reporting historical data for calendar year 2007 and for 1990 through 2006, respectively. Table E.3 provides methane and nitrous oxide emission factors by state for use in reporting historical data for calendar years 1990 through 2007. These emission factors should not be used for current year reporting. For current year reporting, use the emission factors in Appendix C.

Table E.1 Carbon Dioxide Electricity Emission Factors, Calendar Year 2007

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate (lbs/MWh)
AKGD	ASCC Alaska Grid	1,257.19
AKMS	ASCC Miscellaneous	480.10
AZNM	WECC Southwest	1,254.02
CAMX	WECC California	878.71
ERCT	ERCOT All	1,420.56
FRCC	FRCC All	1,327.66
HIMS	HICC Miscellaneous	1,456.17
HIOA	HICC Oahu	1,728.12
MROE	MRO East	1,858.72
MROW	MRO West	1,813.81
NEWE	NPCC New England	908.90
NWPP	WECC Northwest	921.10
NYCW	NPCC NYC/Westchester	922.22
NYLI	NPCC Long Island	1,412.20
NYUP	NPCC Upstate NY	819.68
RFCE	RFC East	1,095.53
RFCM	RFC Michigan	1,641.41
RFCW	RFC West	1,556.39
RMPA	WECC Rockies	2,035.81
SPNO	SPP North	1,971.42
SPSO	SPP South	1,761.14
SRMV	SERC Mississippi Valley	1,135.46
SRMW	SERC Midwest	1,844.34
SRSO	SERC South	1,490.37
SRTV	SERC Tennessee Valley	1,494.89
SRVC	SERC Virginia/Carolina	1,146.39

Source: EPA eGRID2006 Version 2.1, April 2007 (Year 2004 Data).

Figure E.1 shows the eGRID historical subregions. Use this map to identify your subregion for reporting historical data for calendar year 2007. Note that the subregions are the same for calendar year 2007 as the current year.

Figure E.1 Historical eGRID Subregions, Calendar Year 2007

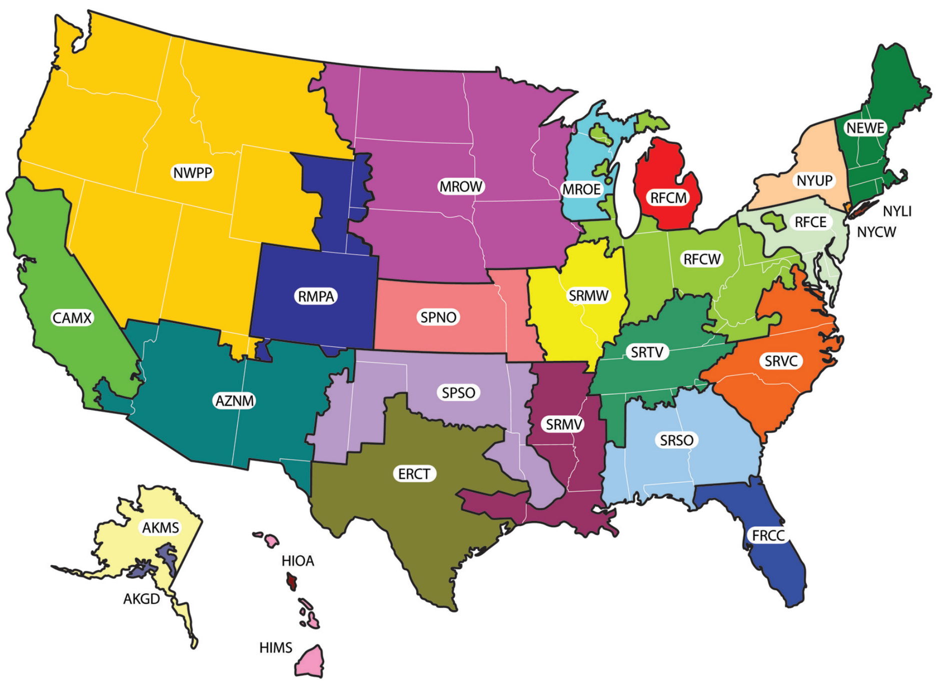


Table E.2 Carbon Dioxide Electricity Emission Factors, Calendar Years 1990 - 2006

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate (lbs/MWh)
AKGD	ASCC Alaska Grid	1,399.95
AKMS	ASCC Miscellaneous	757.81
CALI	WECC California	804.54
ECMI	ECAR Michigan	1,632.06
ECOV	ECAR Ohio Valley	1,966.53
ERCT	ERCOT All	1,408.27
FRCC	FRCC All	1,390.04
HIMS	HICC Miscellaneous	1,702.93
HIOA	HICC Oahu	1,721.69
MAAC	MAAC All	1,097.56
MANN	MAIN North	1,761.09
MANS	MAIN South	1,237.29
MAPP	MAPP All	1,838.83
NEWE	NPCC New England	897.11
NWGB	WECC Great Basin	852.31
NWPN	WECC Pacific Northwest	671.04
NYCW	NPCC NYC/Westchester	1,090.13
NYLI	NPCC Long Island	1,659.76
NYUP	NPCC Upstate NY	843.04
OFFG	Off-Grid	1,706.71
ROCK	WECC Rockies	1,872.51
SPNO	SPP North	2,011.15
SPSO	SPP South	1,936.65
SRMV	SERC Mississippi Valley	1,331.34
SRSO	SERC South	1,561.51
SRTV	SERC Tennessee Valley	1,372.70
SRVC	SERC Virginia/Carolina	1,164.19
WSSW	WECC Southwest	1,423.95

Source: EPA eGRID2002 Version 2.01 Location (Operator)-Based eGRID Subregion File (Year 2000 Data).

Figure E.2 shows the eGRID historical subregions. Use this map to identify your subregion for reporting historical data for calendar years 1990 - 2006.

Figure E.2 Historical eGRID Subregions, Calendar Years 1990 - 2006

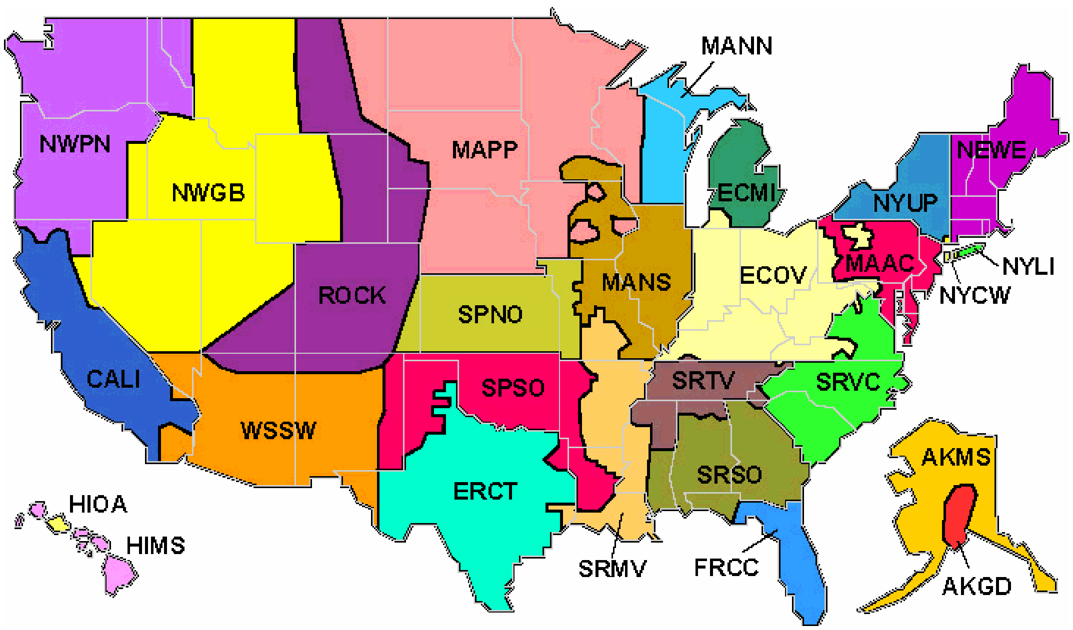


Table E.3 Methane and Nitrous Oxide Electricity Emission Factors by State, Calendar Years 1990 - 2007

Region/State	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
Alabama	0.0137	0.0223
Alaska	0.0068	0.0089
Arizona	0.0068	0.0154
Arkansas	0.0125	0.0203
California	0.0067	0.0037
Colorado	0.0127	0.0289
Connecticut	0.0174	0.0120
Delaware	0.0123	0.0227
Florida	0.0150	0.0180
Georgia	0.0129	0.0226
Hawaii	0.0214	0.0183
Idaho	0.0080	0.0033
Illinois	0.0082	0.0180
Indiana	0.0143	0.0323
Iowa	0.0138	0.0298
Kansas	0.0112	0.0254
Kentucky	0.0140	0.0321
Louisiana	0.0094	0.0112
Maine	0.0565	0.0270
Maryland *	0.0118	0.0206
Massachusetts	0.0174	0.0159
Michigan	0.0146	0.0250
Minnesota	0.0157	0.0247
Mississippi	0.0132	0.0165
Missouri	0.0126	0.0288
Montana	0.0108	0.0227
Nebraska	0.0095	0.0219
Nevada	0.0090	0.0195
New Hampshire	0.0172	0.0141
New Jersey	0.0077	0.0079
New Mexico	0.0131	0.0296
New York	0.0081	0.0089
North Carolina	0.0105	0.0203
North Dakota	0.0147	0.0339

Table E.3 Methane and Nitrous Oxide Electricity Emission Factors by State, Calendar Years 1990 - 2007 (continued)

Region/State	CH_4 (lbs/MWh)	N_2O (lbs/MWh)
Ohio	0.0130	0.0288
Oklahoma	0.0110	0.0223
Oregon	0.0033	0.0034
Pennsylvania	0.0107	0.0203
Rhode Island	0.0068	0.0047
South Carolina	0.0091	0.0145
South Dakota	0.0053	0.0121
Tennessee	0.0105	0.0212
Texas	0.0077	0.0146
Utah	0.0134	0.0308
Vermont	0.0096	0.0039
Virginia	0.0137	0.0192
Washington	0.0037	0.0040
West Virginia	0.0137	0.0316
Wisconsin	0.0138	0.0260
Wyoming	0.0147	0.0338

* Includes the District of Columbia.

Note: All emission factors for electricity generation were derived based on higher heating values (HHV).

Source: Emission factors are derived from: U.S. Department of Energy, Revised/Updated State-level Greenhouse Gas Emission Factors for Electricity (April 2002), http://www.eia.doe.gov/oiaf/1605/e-factor.html. Note: These state-level electricity generation emission factors represent average emissions per kWh or MWh generated by electric utilities for the 1998-2000 time period. They do not include emissions from power produced by non-utility generators.

Appendix F Industry-Specific Metrics for Determining Emission Intensity

The following table provides industry-specific metrics that may be used to measure energy and GHG emissions. It was compiled by researchers at the Lawrence Berkeley National Laboratory (LBNL).

Table F.1 Industry-Specific Metrics, Ranked by California Industrial Combined Electricity and Natural Gas Consumption (Listed by Largest to Smallest Subsector)

SIC Code	Description	Energy Metric	Emissions Metric	Source
13	**Oil and Gas Extraction**			
131	Crude petroleum and natural gas	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
132	Natural gas liquids	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
138	Oil and gas field services	Production Energy Intensity	Production Carbon Intensity (PCI) = CO_2eq./cubic meter oil eq.	CAPP, 2000
29	**Petroleum and Coal Products**			
		Energy Intensity Index (EII)		Solomon Associates, 2001
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
291	Petroleum refining	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/cubic meter fossil fuels	GHG/cubic meter fossil fuels	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
295	Asphalt paving and roofing materials	N/A		
299	Misc. petroleum and coal products	N/A		

SIC Code	Description	Energy Metric	Emissions Metric	Source
20	**Food and Kindred Products**			
201	Meat products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne	GHG/tonne	Institute for Energy Technology, 1998
202	Dairy products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/liter weighted production	GHG/liter weighted production	Institute for Energy Technology, 1998
		Energy/tonne milk and cream	GHG/kiloliter milk and cream	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
203	Preserved fruits and vegetables	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
204	Grain mill products	N/A		
205	Bakery products	Energy/kg bread	GHG/kg bread	Institute for Energy Technology, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
206	Sugar and confectionery products	Energy efficiency index		Ministry of Economic Affairs, 1998
207	Fats and oils	Energy efficiency index		Ministry of Economic Affairs, 1998

SIC Code	Description	Energy Metric	Emissions Metric	Source
20	**Food and Kindred Products**			
208	Beverages	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Soft drinks	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Brewery products	Energy/hectoliter of beer equiv	GHG/hectoliter of beer equiv	Institute for Energy Technology, 1998
		Energy/hectoliter of beer	GHG/hectoliter of beer	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
209	Misc. food and kindred products	N/A		
32	**Stone, Clay, and Glass Products**			
	Glass and glass products	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
321	Flat glass	N/A		
322	Glass & glassware, pressed or blown	N/A		
323	Products of purchased glass	N/A		
324	Cement, hydraulic	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne clinker	GHG/tonne clinker	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	
325	Structural clay products (bricks, tile)	Energy efficiency index		Ministry of Economic Affairs, 1998

SIC Code	Description	Energy Metric	Emissions Metric	Source
32	**Stone, Clay, and Glass Products**			
326	Pottery	Energy Efficiency Index		Ministry of Economic Affairs, 1998
327	Concrete, gypsum & plaster products	N/A		
328	Cut stone and stone products	N/A		
329	Misc nonmetallic mineral products	N/A		
28	**Chemicals and Allied Products**			
		Energy/$ gross output	GHG/GDP	Ministry of Economic Affairs, 1998
		Energy/GDP		Nyboer and Laurin, 2001a
		Energy/GDP		Nyboer and Laurin, 2001b
281	Industrial inorganic chemicals	Energy/tonne inorganic chemicals	GHG/tonne inorganic chemicals	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
286	Industrial organic chemicals	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
287	Agricultural chemicals	Energy/tonne chemical fertilizers	GHG/tonne chemical fertilizers	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
	Chemical fertilizers	Energy/tonne fertilizers	GHG/tonne fertilizers	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
36	**Electronic and Other Electric Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
33	**Primary Metal Industries**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
331	Blast furnace and basic steel	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne steel	GHG/tonne steel	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
332	Iron and steel foundries	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Non-ferrous Metal Smelters & Refineries	Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Primary Production of Aluminum	Energy/tonne aluminum	GHG/tonne aluminum	Institute for Energy Technology, 1998
3335	Aluminum rolling and drawing	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
	Copper/Alloy Roll, Cast & Extrude	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
26	**Paper and Allied Products**			
		Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
26	**Paper and Allied Products**			
261	Pulp mills	Energy/tonne pulpwood	GHG/tonne pulpwood	Institute for Energy Technology, 1998
		Energy/tonne thermomechanical pulp	GHG/tonne thermomechanical pulp	Nyboer and Laurin, 2001a
		Energy/tonne chemical pulp	GHG/tonne chemical pulp	Nyboer and Laurin, 2001b
		Energy/tonne market pulp	GHG/tonne market pulp	
		Energy/$ gross output	GHG/$ gross output	
		Energy/GDP	GHG/GDP	
262	Paper mills	Energy/tonne paper	GHG/tonne paper	Institute for Energy Technology, 1998
		Energy/tonne pulp and paper	GHG/tonne pulp and paper	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
263	Paperboard mills	Energy/tonne paperboard	GHG/tonne paperboard	Nyboer and Laurin, 2001a
34	**Fabricated Metal Products**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
37	**Transportation Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
371	Motor vehicles and equipment	Energy/1000 cars and trucks	GHG/1000 cars and trucks	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
3714	Motor vehicle parts and accessories	Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b

SIC Code	Description	Energy Metric	Emissions Metric	Source
35	**Industrial Machinery and Equipment**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
30	**Rubber and Miscellaneous Plastics Products**			
		Energy efficiency index		Ministry of Economic Affairs, 1998
		Energy/tonne of rubber products	GHG/tonne rubber products	Nyboer and Laurin, 2001a
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001b
		Energy/GDP	GHG/GDP	
22	**Textile Mill Products**			
		Energy/$ gross output	GHG/$ gross output	Nyboer and Laurin, 2001a
		Energy/GDP	GHG/GDP	Nyboer and Laurin, 2001b
		Energy efficiency index		Ministry of Economic Affairs, 1998
227	Carpets and rugs	N/A		
24	Lumber and wood products	N/A		
14	Nonmetallic mineral, except fuels	N/A		
38	Instruments and related products	N/A		
27	Printing and publishing	N/A		
15	General building contractors	N/A		
2	Agriculture production - livestock	N/A		
39	Miscellaneous manufacturing industries	N/A		
23	Apparel and other textile products	N/A		
25	Furniture and fixtures	N/A		
10	Metal mining	N/A		
31	Leather and leather products	N/A		

Appendix G References

Alliance for Responsible Atmospheric Policy, Global comparative analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire protection Applications, Final Report (March 2002).

American Petroleum Institute, Compendium of Greenhouse Gas Emission Estimation Methodologies for the Oil and Gas Industry, Pilot Test Version (April 2001).

Australian Greenhouse Office, Progress Report' Reporting Template (1999).

California Energy Commission, Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999: (2002).

Canada's Climate Change Voluntary Challenge & California Registry Inc., Registration Guide 1999 (1999).

California Energy Commission, Committee Report: Guidance to the California Climate Action Registry: General Reporting Protocol, P500-02-005F (June 2002).

California Energy Commission, Committee Report: Guidance to the California Climate Action Registry: Verification Protocol, P500-02-030F (June 2002).

Gas Technology Institute, GRI-GHGCalc™ Computer Program, Version 1.0, GRI-99/0086 (December 1999).

Intergovernmental Panel on Climate Change, Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000).

Intergovernmental Panel on Climate Change, Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Greenhouse Gas Inventories Reference Manual, Reference Manual, Chapter 1 (1996).

Phylipsen, K., et al., Handbook on International Comparisons of Energy Efficiency in the Manufacturing Industry, Department of Science, Technology, Society, Utrecht University, Netherlands (1998).

World Resources Institute and World Business Council for Sustainable Development, The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (2001), www.ghgprotocol.org.

United Kingdom Department for Environment, Food & Rural Affairs (DEFRA), Draft Framework Document for the UK Emissions Trading Scheme (2001).

United Kingdom Department for Environment, Food & Rural Affairs (DEFRA), Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme (2001).

U.S. Department of Energy, Energy Information Administration, Annual Energy Review 2000, Appendix A, DOE/EIA-0384 (2001).

U.S. Department of Energy, Energy Information Administration, Emissions of Greenhouse Gases in the United States (2000).

U.S. Department of Energy, Energy Information Administration, Instructions for Form EIA-1605 Voluntary Reporting of Greenhouse Gases for Data Through 2000 (2001).

U.S. Department of Energy, Energy Information Administration, Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, General Guidelines (1994).

U.S. Department of Energy, Energy Information Administration, Updated State-level Greenhouse Gas Emission Factors for Electricity Generation (2001).

U.S. Environmental Protection Agency, Estimating Greenhouse Gas Emissions, Volume VIII of the Emissions Inventory Improvement Program (EIIP) Technical Report Series (October 1999).

U.S. Environmental Protection Agency, ClimateWise (1999), http://www.epa.gov/climatewise.

U.S. Environmental Protection Agency, Composition of Refrigerant Blends (May 1998), http://www.epa.gov/ozone/title6/snap/lists/refblend.html.

U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000, EPA-236-R-02-003 (April 2002).

U.S. Environmental Protection Agency, Methods for Estimating Methane Emissions from Natural Gas and Oil Systems. Emissions Inventory Improvement Program, Volume VIII, Chapter 3 (1999).

U.S. Environmental Protection Agency, U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions, EPA-430-R-99-013 (September 1999).

CALIFORNIA ENERGY COMMISSION

California's Water – Energy Relationship

Prepared in Support of the 2005 Integrated Energy Policy Report Proceeding (04-IEPR-01E)

FINAL STAFF REPORT

NOVEMBER 2005
CEC-700-2005-011-SF

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Primary Author
Gary Klein
California Energy Commission

Martha Krebs
Deputy Director
Energy Research and Development Division

Valerie Hall
Deputy Director
Energy Efficiency & Demand Analysis Division

Terry O'Brien
Deputy Director
Systems Assessment & Facilities Siting Division

B. B. Blevins
Executive Director

DISCLAIMER

ACKNOWLEDGEMENTS

The *California's Water-Energy Relationship* report is the product of contributions by many California Energy Commission staff and consultants, including Ricardo Amon, Shahid Chaudhry, Thomas S. Crooks, Marilyn Davin, Joe O'Hagan, Pramod Kulkarni, Kae Lewis, Laurie Park, Paul Roggensack, Monica Rudman, Matt Trask, Lorraine White and Zhiqin Zhang.

Staff would also like to thank the members of the Water-Energy Working Group who so graciously gave of their time and expertise to inform this report.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

As California continues to struggle with its many critical energy supply and infrastructure challenges, the state must identify and address the points of highest stress. At the top of this list is California's water-energy relationship: water-related energy use consumes 19 percent of the state's electricity, 30 percent of its natural gas, and 88 billion gallons of diesel fuel every year – and this demand is growing.

As water demand grows, so grows energy demand. Since population growth drives demand for both resources, water and energy demand are growing at about the same rates and, importantly, in many of the same geographic areas. This dynamic is exacerbated by the fact that Northern California has two-thirds of the state's precipitation while two-thirds of the population resides in Southern California. Water demand and electricity demand are growing rapidly in many of the same parts of the state stressing already constrained electricity delivery systems. When electric infrastructure fails, water system reliability quickly plummets and threatens the public health and safety.

The state water plan concludes that the largest single new supply available for meeting this expected growth in water demand over the next 25 years is water use efficiency. The remainder must be provided by the development of new water supplies including water recycling, and desalination of both brackish and seawater[1], all of which will increase energy demand over current levels.

Worse, the times when the highest energy intensity water supply options will be most needed are most likely to occur during multi-year drought periods when surface water supplies are low and groundwater levels drop, requiring even more energy for pumping each gallon of water. To compound the problem, reduced surface water supplies and snowpack in high elevations are likely to reduce the availability of valuable hydroelectric supplies. Yet, these are also the times when the most aggressive water conservation efforts are implemented, reducing overall water use, which helps reduce the total impact on energy demand. Although the net effects of this dynamic are not fully understood, this report presents current knowledge to assist with further analysis.

This is an urgent time of both challenge and opportunity. The primary finding of this paper is that a major portion of the solution is closer coordination between the water and energy sectors. A meaningful solution cannot be reached in the current regulatory environment where water utilities value only the cost of acquisition, conveyance, treatment, and delivery; wastewater utilities value only the cost of collection, treatment, and disposal; electric utilities value only saved electricity; and natural gas utilities value only saved natural gas. The state must both develop and expand best practices and existing programs to realize the substantial incremental benefits of joint water and energy resources and infrastructure management.

1 State Water Plan, B160-05.

While many nuances of this complex statewide problem are still unclear, staff's analysis shows that significant energy benefits can be reaped through the twin goals of the efficient use of water by end users and the efficient use of energy by water systems. It is also clear that not nearly enough has been done to ensure that California's water supply strategies are synchronized, hand-in-hand, with its energy strategies. Nor has enough been done to forge partnerships between the water and energy sectors so that their natural synergies, joint resources, and assets can be effectively leveraged for the benefit of all Californians.

The state has the opportunity now to reap near-term energy benefits by helping California's water and wastewater utilities become more energy self-sufficient, which will ease pressures on California's already stressed electric system. By adjusting existing policies, programs, and resources, water and wastewater utilities could be converted from high energy users to net renewable energy producers.

California's water and energy policymakers need to commit today to the joint planning and management of these critical resources. The state's water plan and resource strategies are being reviewed with all key stakeholders, and implementation plans are already on the drawing table. At the same time, the California Public Utilities Commission has approved substantial utility ratepayer expenditures in energy efficiency programs for the 2006-2008 program cycle. The state must waste no time in taking advantage of these rapidly evolving events.

The state can meet energy and demand-reduction goals comparable to those already planned by the state's investor-owned energy utilities for the 2006-2008 program period by simply recognizing the value of the energy saved for each unit of water saved. If allowed to invest in these cold water energy savings, energy utilities could co-invest in water use efficiency programs, which would in turn supplement water utilities' efforts to meet as much load growth as possible through water efficiency. Remarkably, staff's initial assessment indicates that this benefit could be realized at less than half the cost to electric ratepayers of traditional energy efficiency measures.

This staff report examines how energy is used – and how it can be saved – in the water use cycle. The strategies and goals for a comprehensive statewide water-energy program would achieve incremental energy benefits for water and energy utilities. The overarching goal of establishing a comprehensive statewide water-energy program would create a dynamic, living process where key stakeholders have incentives to continuously identify and implement strategies optimizing the state's water and energy resources and assets on an integrated, coordinated, and collaborative basis. This opportunity must not be lost since the need is so great. Because of all these factors, staff recommends that an action-oriented approach structured to achieve near-term results be developed immediately.

INTRODUCTION

The California Energy Commission's (Energy Commission) *California's Water Energy Relationship* staff report is part of the *Integrated Energy Policy Report* (*Energy Report*) proceeding. It was prepared to promote greater understanding of the critical symbiotic relationship between the water and energy sectors, especially electricity. In its scoping order, the Energy Commission stated that:

- "(f)or 2005, the Committee will continue the emphasis from the *2003 Energy Report* on increasing the level of energy efficiency and diversity in the state's energy systems and understanding the limitations of the state's electricity, natural gas, and transportation fuel infrastructure." [2]
- "The need for new water supplies in California and the West due to population growth and potential changes in the state's hydrological cycle has important implications for the state's energy system that are not yet fully understood. The *2005 Energy Report* will need to evaluate this issue as part of pursuing the broader goal of sustainability.[3]
- "To meet the challenge of sustainability, California's energy and environmental agencies, along with key private and public stakeholders, must work together to address critical issues that include:

  > Impacts of water demand and supply strategies, including the need for increased pumping to provide reliable water supplies, increased need for water treatment, and possible development of desalination facilities..."[4]

This report examines the dynamic give-and-take relationship between California's water and energy resources. Among many other issues, this staff report examines the state's water sector and its energy use, along with changes likely to occur in the future. The staff considered various components of the system and the energy implications, or characteristics of these components, for both energy use and generation. With the participation of a broad base of key stakeholders, the staff evaluated actions and methods that can boost the synergistic efficiencies of both the energy and water sectors. This report is meant to inform and provide technical support for decision makers, water and energy industry professionals, and the general public about critical energy supply and demand issues plaguing the state's water sector today.

---

[2] California Energy Commission, Integrated Energy Policy Report Committee Scoping Order, dated September 3, 2004, p. 2.
[3] Ibid.
[4] Ibid, p.7.

This study presents the best, most updated available information on linkages between California's energy and water sectors. The process to develop this report included two public workshops, several meetings of an ad hoc working group[5] formed for the study, and interviews with scores of water professionals. This outreach included two meetings with members of the Association of California Water Agencies, which represents about 90 percent of the state's water agencies (many of which also operate wastewater treatment facilities), members of the California Municipal Utilities Association, and participation in the annual plenary of the California Urban Water Conservation Council.

The following key concepts form the basis of the analysis in this paper:

- ***Water and energy relationship:*** Refers to the types and magnitude of water and energy interdependencies requiring documentation and evaluation for various types of water resources, end uses, systems, and processes in order to fully understand the water-energy tradeoffs under different resource planning scenarios. In this report staff uses ***water and energy utilities*** when encompassing all water, wastewater, electricity, natural gas, and diesel fuel suppliers, utilities, and districts, both public and private.

- ***Water use cycle:*** Refers to the overall process of collecting, developing, conveying, treating, and delivering water to end users; using the water; and collecting, treating, and disposing of wastewater.

- ***Energy intensity:*** Energy intensity is defined as the amount of energy consumed per unit of water to perform water management-related actions such as desalting, pumping, pressurizing, groundwater extraction, conveyance, and treatment - for example, the number of kilowatt-hours consumed per million gallons (kWh/MG) of water. This concept is applied to water supplies, to components of the water use cycle, and to the total energy intensity of a unit of water throughout the entire water use cycle.

- ***Energy self-sufficiency:*** Refers to an entity that supplies its own energy requirements. This would typically be done through a combination of energy efficiency and self-provision of power, whether purchased or produced.

- ***Integrated water and energy resource management:*** Refers to the comprehensive body of policies, practices, methods, tools, and procedures

[5] The Water-Energy Relationship Working Group consists of representatives from state water and energy-related government agencies, local and regional water agencies, industry organizations, environmental and citizen groups, and other key water professionals. It was established to help guide and critique this Staff Paper, but its life is expected to extend beyond the WER study process to work on other planning efforts, such as DWR's Water Plan process, and perhaps a planning effort related to optimization of pumped-storage opportunities in the state. The transcripts of all Water-Energy Relationship Working Group meetings on pumped-storage will be made available to the public and will become part of the record of evidence for the 2005 Energy Report.

that collectively comprise “statewide integrated water and energy resource planning and management.” Appendix A summarizes most of the existing organizations, programs, and research. Optimal integration is presently beyond the reach of both water and energy resource management best practices.

Chapter 1 describes California’s water-energy relationship – what it is and what it means within the context of California’s current energy circumstances. Chapters 2, 3, and 4 examine the primary components of the entire water cycle and address their energy intensity. Chapter 5 discusses the potential development of new renewable energy resources by water and wastewater utilities. Chapter 6 explores different types of future changes likely to affect the energy intensity of water supplies; water treatment and distribution; water end use; and wastewater treatment and disposal. Findings and recommendations are contained in Chapter 7. Appendices appearing at the end of the report provide additional detail, and a glossary of terms is included.

CHAPTER 1 - WHAT IS THE WATER-ENERGY RELATIONSHIP?

The nation's water and energy resources are inextricably entwined. Energy is needed to pump, treat, transport, heat, cool, and recycle water. On the flip side, the force of falling water turns the turbines that generate hydroelectric electricity, and most thermal power plants are dependent on water for cooling. In California, an elaborate system of manmade storage, treatment and conveyance structures exist to augment natural hydrologic features. This system not only helps produce needed electricity supplies but requires large amounts of energy to deliver quality water where Californians need and want it.

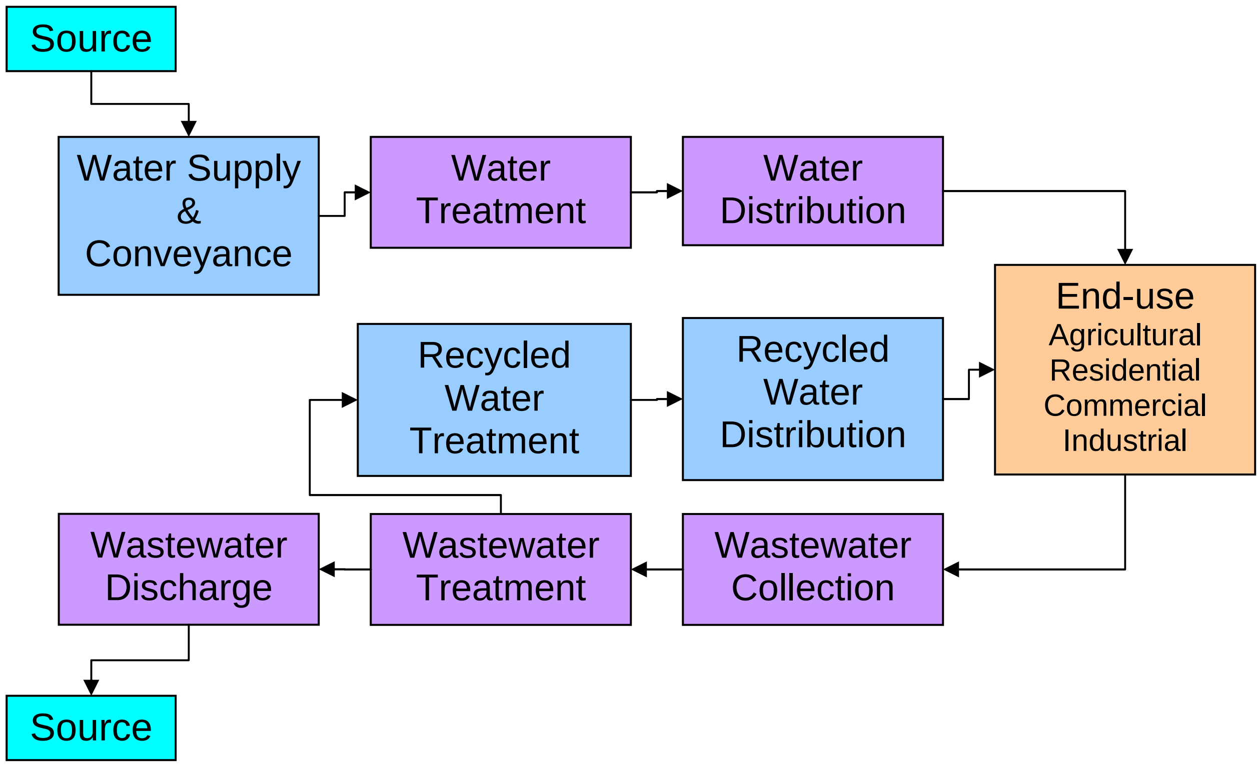
This chapter describes the overall water use cycle and introduces the concept of energy intensity. The energy intensity framework in the water use cycle helps identify opportunities for changing the pattern and magnitude of water-related energy consumption in California.

The Water Use Cycle

The Water-Energy Relationship Working Group discussed the state's water use cycle at length. While there are exceptions, Figure 1-1 illustrates the state's typical cycle.[6] Turquoise blue represents sources of water, water supplies are shown in light blue, water and wastewater treatment are shown in purple, and end use is shown in beige.

[6] This schematic is based on work by Dr. Robert Wilkinson (Wilkinson, Robert C., 2000. *Methodology For Analysis of The Energy Intensity of California's Water Systems, and an Assessment of Multiple Potential Benefits Through Integrated Water-Energy Efficiency Measures*, Exploratory Research Project, Ernest Orlando Lawrence Berkeley Laboratory, California Institute for Energy Efficiency) and on Wilkinson and Gary Wolff in current work on the energy intensity of water in California with additions by Energy Commission staff.

Figure 1-1: California's Water Use Cycle



Water is first diverted, collected, or extracted from a source. It is then transported to water treatment facilities and distributed to end users. What happens during end use depends primarily on whether the water is for agricultural or urban use. Wastewater from urban uses is collected, treated, and discharged back to the environment, where it becomes a source for someone else. In general, wastewater from agricultural uses does not get treated (except for holding periods to degrade chemical contaminants) before being discharged directly back to the environment, either as runoff to natural waterways or into groundwater basins. There is a growing trend to recycle some portion of the wastewater stream – recycled water – and redistributing it for non-potable end uses like landscape irrigation or industrial process cooling.

Water-Related Energy Use

Energy is required at all stages of the water use cycle. It is difficult to measure the amount of water-related energy that is actually consumed. Better information is available about energy consumption by water and wastewater utilities. However, energy consumption by water users is harder to determine since electric and gas meters do not separately measure water-related uses.[7]

The data presented in Table 1-1, with supporting details in Appendix B: 2001 California Energy Consumption by End Use, are based on information provided by the state's energy utilities to the Energy Commission for use in demand forecasting.[8] The Water-Energy Relationship Working Group and other stakeholders participated in extensive discussions to help staff estimate the magnitude of water-related energy consumption by water and wastewater utilities, and agricultural and urban water end users. As shown in Table 1-1, these estimates indicate that total water-related consumption is large – 19 percent of all electricity used in California, approximately 30 percent of all natural gas, and more than 80 million gallons of diesel fuel. The Energy Commission is funding a research project to refine the numbers, and results are expected in early 2006.

Table 1-1: Water-Related Energy Use in California in 2001

<table>
<tr><th></th><th>Electricity (GWh)</th><th>Natural Gas (Million Therms)</th><th>Diesel (Million Gallons)</th></tr>
<tr><td colspan="4">Water Supply and Treatment</td></tr>
<tr><td>Urban</td><td>7,554</td><td>19</td><td>?</td></tr>
<tr><td>Agricultural</td><td>3,188</td><td></td><td></td></tr>
<tr><td colspan="4">End Uses</td></tr>
<tr><td>Agricultural</td><td>7,372</td><td>18</td><td>88</td></tr>
<tr><td>Residential</td><td rowspan="3">27,887</td><td rowspan="3">4,220</td><td rowspan="3">?</td></tr>
<tr><td>Commercial</td></tr>
<tr><td>Industrial</td></tr>
<tr><td>Wastewater Treatment</td><td>2,012</td><td>27</td><td>?</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Total Water Related Energy Use</td><td>48,012</td><td>4,284</td><td>88</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Total California Energy Use</td><td>250,494</td><td>13,571</td><td>?</td></tr>
<tr><td>Percent</td><td>19%</td><td>32%</td><td>?</td></tr>
</table>

Source: California Energy Commission

The data in this table have been organized to align with the water use cycle in Figure 1-1. Water supply and treatment corresponds to the part of the water use

[7] Meters are typically installed to record all the electricity or natural gas use by an entire household, building or other type of facility.
[8] Agricultural data in this table is taken from Tables 1-4 and 1-5 in this chapter.

cycle between the source and end-user. Water supply and treatment account for 22 percent of water-related electricity consumption; 70 percent is required by urban water users and 30 percent by agriculture. On-farm agricultural water use consumes additional energy, estimated at 15 percent of water-related electricity demand. Residential, commercial, and industrial end uses combined represent 58 percent of the electricity consumed. Wastewater treatment accounts for 4 percent. The vast majority of water-related natural gas consumption is by residential, commercial, and industrial customers, primarily for heating water. Natural gas consumption in the agricultural sector is primarily for irrigation pumping. Agriculture is the only sector where diesel fuel consumption, which is also used for water pumping, is quantified. Question marks in the table indicate areas where additional information is needed.

The Energy Intensity of the Water Use Cycle

Each element of the water use cycle has unique energy intensities (kilowatt hours/million gallons (kWh/MG)). Table 1-2 illustrates the considerable variability in both the range of intensities for each segment and the components of the water use cycle. End use energy demand was excluded since the focus is on the energy requirements in the remaining conveyance, treatment, distribution, and wastewater treatment processes. Details supporting this table are in Appendix C: Energy Impact Analysis of Existing Water Management Practices.

Table 1-2: Range of Energy Intensities for Water Use Cycle Segments

	Range of Energy Intensity kWh/MG	
Water-Use Cycle Segments	**Low**	**High**
Water Supply and Conveyance	0	14,000
Water Treatment	100	16,000
Water Distribution	700	1,200
Wastewater Collection and Treatment	1,100	4,600
Wastewater Discharge	0	400
Recycled Water Treatment and Distribution	400	1,200

<u>Water Supply and Conveyance</u>
Energy intensity for this portion of the water use cycle is determined primarily by the volume of water that is transported, the distance, and the changes in topography along its route. California's water supply varies significantly with annual and seasonal hydrologic conditions, and with climate, geography, and topography. Nearly 70 percent of the state's total stream runoff is north of Sacramento, but 80

percent of the water demand is south of Sacramento. This creates challenges that policymakers have struggled to resolve for nearly a century.

The energy intensity of collection, extraction, and conveyance of raw water supplies can be near zero for gravity-fed systems from the Sierra to both urban areas in Northern California and agricultural districts in the Central Valley. However, other systems use very large pumps to transport large volumes of water hundreds of miles from points of collection to points of need. As a consequence, the energy intensity of water supplies in Central and Southern California is typically much higher than in Northern California, with Southern California the highest due to the need to transport water more than 3,000 feet up over the Tehachapi Mountains.

<u>Water Treatment</u>
Some sources of water need very little treatment, so their energy intensity is low. Other sources, such as brackish groundwater or seawater desalination, require much more treatment so their energy intensity is significantly higher. The energy intensity also varies depending on the intended end user. For example, most agricultural and some industrial end users can use water that requires little or no treatment, while most residential and commercial users need water treated to potable standards.

Energy use for water treatment will increase as more stringent water quality rules are implemented under the Safe Drinking Water Act and the Clean Water Act. These new rules require multi-stage disinfection - including treating potable water more than once to ensure the removal of harmful organisms that may grow during storage and transport - and improved disinfection technologies that reduce risk of carcinogens and other potentially harmful disinfection by-products. These improved disinfection technologies – principally, ultraviolet treatment and ozonation – are much more energy intensive than prior chemical methods.[9]

<u>Water Distribution</u>
Some fresh water distribution systems are gravity fed, but most require some pumping. The primary driver of increased energy for water distribution is urban growth.

<u>Wastewater Collection</u>
Some wastewater collection systems use gravity to bring the wastewater to a treatment plant. Others need energy to lift or transfer the wastewater.

<u>Wastewater Treatment</u>
All wastewater treatment systems require energy, though some require more than others depending on the quality of the waste stream, the level of treatment required, and the treatment technologies used. Energy use for wastewater treatment is expected to increase with adoption of more stringent water quality rules under the

[9] There may be some energy savings that are not considered here due to the reduction in needed chemicals for treatment.

Clean Water Act. However, by increasing the quality of wastewater effluent, more recycled water can be added to the state's water supply portfolio.

Wastewater Discharge
Some wastewater discharge systems use gravity to return wastewater to the environment. Others need energy to lift or transfer the wastewater.

Recycled Water and Distribution
Depending upon the level of wastewater treatment in existing facilities, the effluent may be recyclable without requiring additional treatment to displace potable water sources used for non-potable applications. More energy is needed if additional treatment is required. Most recycled water distribution systems require additional energy to pump water uphill to intended users.

As noted previously, since there are so few options to make new water, the increased use of recycled water is a major strategy in the state's water plan.

Energy Intensity in Northern and Southern California

Due to significant variations in energy used to convey bulk water supplies from one place to another, the average energy intensity of the water use cycle in Southern California is much higher than in Northern California. This is due to the fact that Southern California imports about 50 percent of its water supplies from the Colorado River and from the State Water Project (SWP) – each of which is more energy intensive than any single source of water supply used in Northern California.

Table 1-3 shows the combined energy intensity of the water use cycle for typical urban communities in Northern and Southern California. Details supporting this table can be found in Appendix C.

Table 1-3: Electricity Use in Typical Urban Water Systems

	Northern California	Southern California
	kWh/MG	kWh/MG
Water Supply and Conveyance	150	8,900
Water Treatment	100	100
Water Distribution	1,200	1,200
Wastewater Treatment	2,500	2,500
Total	3,950	12,700
Values used in this report	4,000	12,700

Staff recognizes that no two water treatment, distribution, or wastewater treatment systems are identical, so the relative energy intensities reflected above are prototypical. However, within these processes, variability is lower in magnitude than with conveyance and is not linked to a north/south differentiation. The primary north/south regional variation that causes the state's unique and important water energy dynamic is linked to the magnitude of energy required to convey Northern California water supplies to Southern California.

On average, water conveyance requires more than 50 times the energy for Southern California than it does for Northern California. This is also five times the national average. Southern California depends heavily on water imports from the Colorado River and from Northern California. This water travels hundreds of miles through pipelines and aqueducts and, in some places, must be pumped over mountain ranges before reaching its destination. Conversely, 40 percent of Northern California's population is served by gravity-fed systems, with the balance supplied by surface supplies or relatively shallow wells. Recognizing that the actual energy intensity in each component of the water use cycle will vary by utility, the energy values reflected above appear to be reasonable and conservative. This paper assumes that 4,000 and 12,700 kWh per million gallons are consumed for water that is supplied, treated, consumed, treated again, and disposed of in Northern and Southern California, respectively.

Water End Use Energy

California uses about 14 trillion gallons of water in a normal year, with about 79 percent used for agriculture and the remainder in the urban sector. Once water is delivered, customers use it in a variety of applications. Combined agricultural, residential, commercial, and industrial water-related end uses account for 58 percent of all water-related electricity and 99 percent of water-related natural gas use.

Agriculture

Agricultural water use can be both energy intensive, requiring extensive pumping and, in some cases, treatment; but it can also be essentially energy-free, using gravity alone to flow raw surface water onto fields. Each year, California's agricultural sector uses roughly 34 million acre-feet of water to grow food and fiber commodities. It takes more than 10,000 GWh of electrical power to pump and move this water. The energy is used by large state and federal water projects, by irrigation districts, and by on-farm requirements, as outlined in Table1- 4 below.

Table 1-4: Energy Consumed in Agriculture for Water

Category	Energy Consumption (GWh)[1]
Conveyance to Irrigation Districts by the State and Federal water projects[2]	1,720
Conveyance to Irrigation Districts by the Western Area Power Administration	400
Irrigation District surface water pumping	822
Irrigation District ground water pumping	246
On-farm ground water pumping	4,499
On-farm booster pumping[3]	2,873
Subtotal	10,560
Electric equivalent for diesel and natural gas engine driven water pumping[4]	1,231
Total	11,791

[1]Values shown in this table only include agricultural water pumping to meet crop applied water demands. Other agricultural water uses not included in this table include water used for livestock and food processing that is not considered to be commercial. Source: California Agricultural Water Electrical Energy Requirements, ITRC Report No. R 03-006, Irrigation Training and Research Center, 2003 http://www.itrc.org/reports/cec/energyreq.html
[2] Energy used to pump surface water through state and federal water projects to supply irrigation and water districts.
[3]This includes groundwater and surface water pumping to supply pressurized irrigation systems such as sprinkler, drip, and micro spray.
[4]Diesel and natural gas are the second and third most prevalent energy sources used to pump agricultural water. These sources are used to run engines that directly run the water pumps, typically for on-farm groundwater and booster pumping. Emissions requirements typically prevent the use of diesel for pumping in irrigation districts.

The numbers in Table 1-4 represent energy consumption for a typical weather or water year. These numbers will change with different water year scenarios. For example, during a wetter-than-average year with larger surface water deliveries, the energy used for groundwater pumping will decrease. During a period of several back-to-back dry years, a significant amount of additional energy will be used because of increased on-farm groundwater pumping.

In general terms, the electricity used for water represents more than 90 percent of the total electricity used for crop production in the agricultural sector. This applies mostly to field crops, but also to the state’s fruit and nut trees and vineyards.

Dairy farms use electricity and other fuels for pumping water for crops, heating water for cleaning and disinfecting barns, and transporting wastewater for lagoon disposal and aerators. Most of the remaining electricity is used for milking equipment and refrigeration. Fans are also used for animal cooling. Greenhouses and nurseries use electricity and other fuels for watering crops, ventilation, and heating. Other agricultural on-farm electricity use goes to food processing including washing, packaging, and refrigeration. However the majority of food processing is in large-scale processing facilities typically classified as industrial. Their energy requirements are discussed in the section describing industrial water users.

Although most agricultural electricity use is during the summer months, there are many year-round operations including dairies, nurseries and greenhouses, feedlots, and other animal production farms.

As shown in the previous table, diesel and natural gas are also used to pump water. Table 1-5 provides an estimate of the breakdown between diesel and natural gas used for agricultural water use in California (Cal Poly 2003).

Table 1-5: Estimates for Diesel and Natural Gas Engine Driven Water Pumping in California Agriculture

Type	Number of Engines[1]	Fuel Required	Conversion to kWh[2]	Equivalent Electricity (GWh)
Natural Gas	1,932	17.5 Million Therms	6.76 kWh/Therm	118
Diesel	12,535	88 Million Gallons	12.8 kWh/gallon	1,113
Totals	14,467			1,231

[1] These data were generated by Cal Poly ITRC during the analysis for the *California Agricultural Water Electrical Energy Requirements Report* (2003). However, it was not published in that report (Cal Poly ITRC unpublished data, 2005). It was subsequently submitted as testimony in the June 21, 2005, IEPR workshop.
[2] The total number of diesel-and natural gas-engine-driven water pumps was obtained from the 2003 USDA Farm and Ranch Irrigation Survey. In comparison, the estimate used for the 2005, AG-ICE proceeding with the CPUC (A.04-11-007/008) provided by the California Air Resources Board (CARB) reported about 8200 diesel driven irrigation pumps. The estimate from CARB is low compared to the USDA survey. We chose the USDA data because they survey more farms throughout California [http://www.nass.usda.gov/census/census02/fris/tables/fris03_20.pdf].
[3] The conversion from kWh to therms and gallons of diesel is based on the Nebraska Performance Standards for Irrigation Energy Sources (Source: Dorn, T.W., P.E. Fishbach, D.F. Eisenhauer, J.R. Gilley, and L.E. Stateson, *It Pays to Test Your Irrigation Pumping Plant*. Publication EC-713. Lincoln: University of Nebraska, Cooperative Extension Service).

Changes to air quality regulations in agricultural regions will likely lead to conversion of many of these pumps, primarily the diesel-powered ones, to electric pumps. If they were all converted to electric, this would increase the electric requirements of the agricultural sector by more than 10 percent. Although the total number of potential conversions is limited by regulation and available program incentives, the state's planners and electric utilities will need to account for and supply the additional peaking capacity and electricity needed for these pumps. This is discussed in more detail in Chapter 4.

Residential, Commercial and Industrial

Staff has only recently focused on water-related energy consumption in the residential, commercial, and industrial sectors, collectively referred to as urban water users. Table 1-6 presents the aggregated data for each sector. Detailed information can be found in Appendix B.

Table 1-6: End-Use Energy Associated with Urban Water Users

Sector	Electricity (GWh)	Natural Gas (Million Therms)
Residential	13,528	2,055
Commercial	8,341	250
Industrial	6,017	1,914
Total	**27,887**	**4,220**

Source: California Energy Commission

The residential sector accounts for 48 percent of both the electricity and natural gas consumption associated with urban water use. Residential water uses include personal hygiene (shower, bath, sink), dish and clothes washing, toilets, landscape irrigation, chilled water and ice in refrigerators, and swimming pools and spas. Residential energy uses related to these activities include water treatment (filtering and softening), heating (natural gas or electric water heaters), hot water circulation loops, cooling (icemakers and chilled water systems for HVAC and chilled drinking water), circulation (spa pumps, as one example), and, in some cases, the groundwater pumping of private wells.

Commercial water-related energy use represents 30 percent of the electricity and 6 percent of the natural gas use. Industrial water-related energy use represents 22 percent of the electricity and 45 percent of the natural gas. Commercial and industrial water uses include all those found in residences, plus hundreds more. Some of the more energy-intensive applications related to commercial or industrial water use include high-rise supplemental pressurization to serve upper floors, steam ovens and tables, car and truck washes, process hot water and steam, process chilling, equipment cooling (x-ray machines, for example), and cooling towers. In the commercial sector, the major water-related end uses that use electricity are cooling and water heating. Cooling towers for air conditioning are large water users. In the industrial sector, water-related energy use is very dependent upon specific processes. Except for oil and gas extraction, no single industrial category stands out as a major user of electricity or natural gas. Water heating and process heating are the largest users of natural gas.

In general, urban water use in California is more energy intensive than agricultural water use. This is because every urban water system requires energy for water and wastewater treatment, both of which are not generally required for agriculture. The vast majority of urban water systems also require energy for distribution.

Hydropower Production, Energy Recovery, and Renewable Resources

Hydropower

The most widely recognized aspect of the water-energy relationship is hydropower production. As discussed in Chapter 2, California is served by a vast system of reservoirs and dams, pumped storage, and run-of-river facilities. These facilities are operated by investor-owned utilities (IOU), publicly owned utilities (POU), state and federal agencies, irrigation districts, and other entities, mostly to serve multiple purposes including power generation, water supply, recreation, and flood control. California's hydropower system provides valuable peaking reserve capacity, spinning reserve capacity, load following capacity, and transmission support, all at low production costs.[10] California's combined total hydroelectric capacity is more than 14,000 megawatts (MW)[11] or about one-quarter of the in-state generation capacity. Hydro-generated energy was about 29,000 GWh, or 13 percent of the in-state generation in 2004.[12] The state has conducted extensive studies on traditional hydropower, both in the contexts of its value to the California electric system and issues relating to environmental impacts. Staff refers the reader to these existing reports reference herein, all of which are available on the Energy Commission's Web site.

[10] California Energy Commission Staff Report, *California Hydropower System: Energy and Environment*, Appendix D, *2003 Environmental Performance Report*; prepared in support of the Electricity and Natural Gas Report under the Integrated Energy Policy Report Proceeding (02-IEP-01), October 2003 [Publication 100-03-018].
[11] California Energy Commission, *2003 Environmental Performance Report*. Appendix D, *California Hydropower System: Energy and Environment*, Sacramento, CA. 100-03-018, March 2003, p. D-6.
[12] California Energy Commission, *Potential Changes in Hydropower Production from Global Climate Change in California and the Western United States*, June 2005, consultant report, Prepared in support of the *2005 Integrated Energy Policy Report*, Publication No. CEC 700-2005-010.

Energy Recovery from the Water Use Cycle

In-Conduit Hydropower

The state's large water conveyance projects already take advantage of the energy in the water flowing through their pipelines. Wherever there is flowing water, there exist both energy and the potential to capture and utilize that energy. Pipelines that convey water supplies by gravity have energy that could be captured, but care must be taken to make sure that sufficient 'head', or force, remains to carry the water to its final destination. Wherever pressure-reducing valves or stations are used to reduce the energy in moving water, there is an opportunity for energy production. At any point in a water or wastewater system where influent is delivered for treatment or wastewater effluent is discharged, there may be further opportunities for power production. Barriers and challenges to additional development of in-conduit hydropower that recovers energy from the water delivery and conveyance process are discussed in more detail in Chapter 5.

Biogas

Another option for developing generation in the water sector is to increase beneficial use of digester gas produced by the sewage wastewater, dairy manure, and food processing wastes/wastewater. Biogas, composed primarily of methane, can be used for combined heat and power (CHP) production.

California has 311 sewage wastewater treatment facilities, 2,300 dairy operations, and 3,000 food processing establishments. Currently, about 50 percent of sewage sludge, 2 percent of dairy manure, and less then 1 percent of food processing wastes/wastewater generated in the state are used to produce biogas. Converting these wastes into energy can help operating facilities offset the purchase of electricity and provide environmental benefits by reducing discharged air and ground water pollutants.

The Energy Commission is working with Commerce Energy Inc. and Inland Empire Utility Agency (IEUA) to develop technologies that will address the lack of knowledge of the relationship between various co-digestion feedstocks (sewage sludge, food processing wastes, and dairy manure) and gas production.

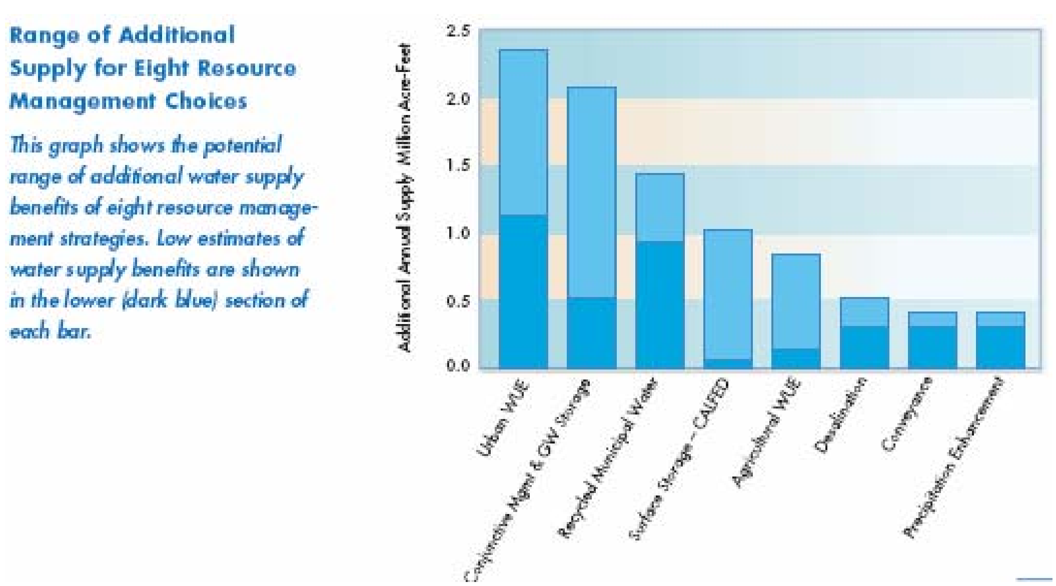
Other Renewable Energy Resources

Water and wastewater agencies typically have very large landholdings with characteristics that readily lend themselves to the development of renewable resources, especially wind and solar. These resources could be used to help California meet its aggressive Renewable Portfolio Standard (RPS) goals. For example, regional water and wastewater agencies have hundreds of miles of rights-of-way, often in areas suitable for solar production. These agencies also have watershed lands that collect water for end-use applications, either potable or for agricultural or industrial use. In order to protect the water quality, large portions of these watershed lands are inaccessible to public recreational use. Many are remotely located, which make their visual impact of little public concern. Watershed lands are also at higher elevations, where wind resources are typically of fairly good quality. Some wastewater utilities also have extensive lands, which are used to dispose of treated effluent and are inaccessible to the public. Municipal or governmental control over these lands could accelerate their use as sites for renewable energy generation

A Loading Order for Water Resources

The *California Water Plan Update 2005,* prepared by the Department of Water Resources (DWR), established a strategic plan that prioritized resource measures to meet new load growth and other water supply challenges. As shown in Figure 1-2, first among the strategies is increased urban water efficiency. Appendix D provides an excerpt of the plan from the Water Plan Update. Thereafter, the plan depends upon increased reliance on conjunctive management and groundwater, followed by recycled water. Agricultural water use efficiency is also an important strategy.

Figure 1-2: New Water Supplies for California



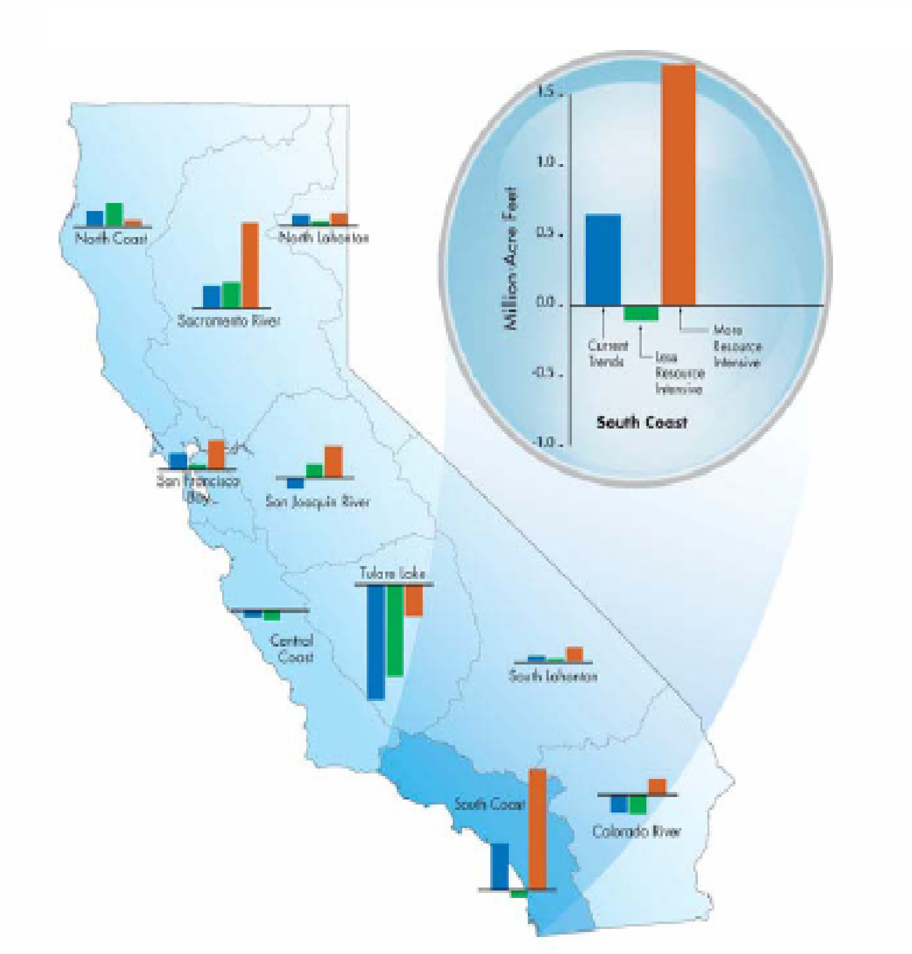
Source: *2005 State Water Plan Update*, DWR.

In many respects, the *2005 Water Plan Update* mirrors the state's adopted loading order for electricity resources described in the Energy Commission's *Integrated Energy Policy Report 2005* and the multi-agency *Energy Action Plan*. The first three strategies all concern the efficient use of existing resources. These strategies encompass efficient use, efficient operations and management, and efficient reuse. Including agricultural water use efficiency, the state's water resources strategy targets will meet 70 percent of future growth in water demand through efficiency measures.

This is a very important concept. Specifically, like energy utilities, water utilities already apply integrated resource planning tools and techniques in their future plans. Similar to energy utilities, they also already apply strategies of "least-cost, best-fit." Thus, in order to optimize the state's water and energy resources on an integrated basis, the primary concept that needs to be integrated into California's water planning on the supply side is the energy intensity of various water supply options. On the demand side, the primary concept is recognition of the energy embedded in various types of water end use throughout the entire water use cycle. Just as energy efficiency increases available supplies and avoids incremental infrastructure costs and environmental impacts, every unit of water not consumed can displace a more energy-intensive water source.

In many cases, the areas of the state that are most stressed with respect to water supplies are also areas with transmission congestion and shortages of local energy supplies. Not surprisingly, since load growth is largely driven by population growth, the geographic areas most resource constrained are the same for both water and for energy. Figure 1-3 shows the projected water demand as estimated by DWR for three different future scenarios and demonstrates the sizable gap between the less and more water-resource-intensive projections. This makes a compelling case for close coordination between water and energy planning and synchronization of both resources and infrastructure goals.

Figure 1-3: Net Change in Average-Year Water Demand for 3 Scenarios by Region, 2000-2030

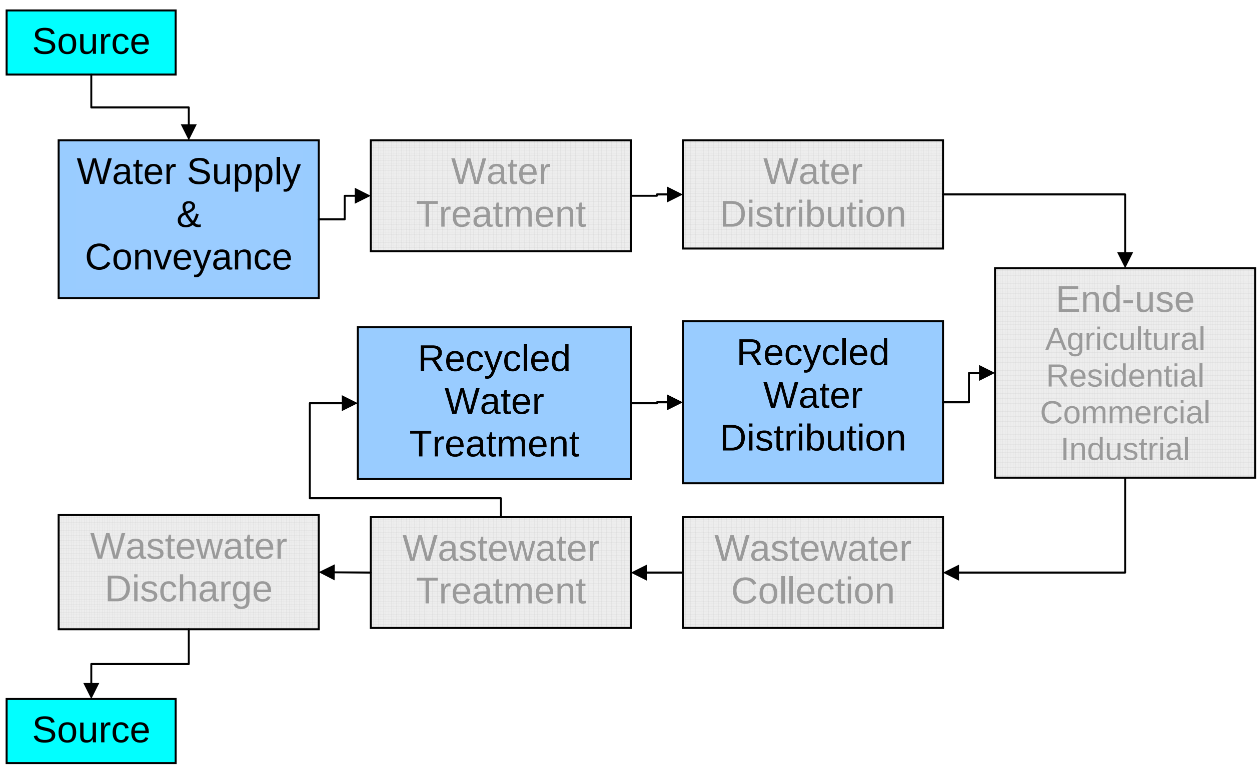


Source: *2005 State Water Plan Update*, DWR.

CHAPTER 2 – WATER SUPPLY AND CONVEYANCE

This section discusses the energy intensity of different water supply sources, all the way through the cycle to conveyance for water treatment. Recycled water, a by-product of wastewater treatment, is also discussed here as an additional source of supply.

Figure 2-1: Water Use Cycle - Supply Source



Primary Sources of California Water

Californians collectively use about 43 million acre-feet (about 14 trillion gallons) of developed water for urban and agricultural use in a normal year. Of this total, 34 million acre-feet go to agriculture (about 11 trillion gallons and 79 percent) and 9 million acre-feet (about 3 trillion gallons and 21 percent) go to the urban sector.[13]

Understanding the energy implications of water use in California requires a basic knowledge of the various water systems that collect, store, and transport water

[13] DWR *2005 Water Plan Update* Volume 1, Table 3-1.

supplies. These supplies can be roughly categorized as surface water, groundwater, desalted water, and recycled water.

- Surface water comes from precipitation, rain and snow, captured and stored in natural lakes and streams, and manmade reservoirs, canals or aqueducts. Most surface water storage is fed from runoff coming from the state's large mountain ranges. The greatest source of surface water supplies is the Sierra snowpack, which holds more water than all of the state's lakes and reservoirs put together, and conveniently melts during the warmer and drier months when California most needs water.

- Groundwater is precisely that – water stored in the ground. Rain directly irrigates farms and gardens but also feeds groundwater basins and aquifers.[14]

- Recycled water, also known as "reclaimed" water or "reuse", is water produced from wastewater effluent. Water quality regulations specify approved uses for recycled water. The level of use depends upon the level of wastewater treatment applied.

- Ocean or brackish water is used for some industrial purposes but must be treated to remove salts and dissolved solids (desalted) for agricultural and urban purposes.

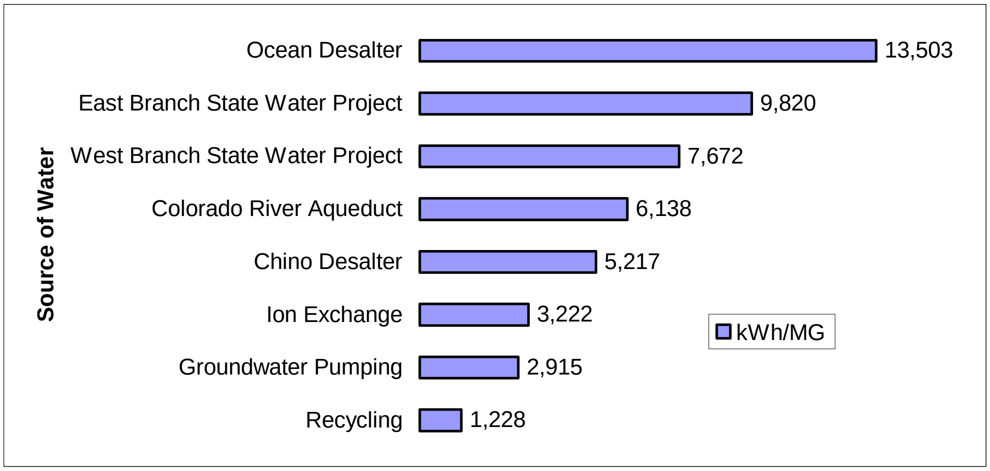
According to DWR's *2005 Water Plan Update*, surface water accounts for more than 60 percent of the state's water use in a typical hydrology year. Groundwater accounts for about 30 percent, although this is highly variable since groundwater makes up most of the state's water supply shortages in dry years. Use of desalted and recycled water, while still a very small percentage of California's total water supply portfolio, is increasing -- both as a means to supplement limited water supplies and provide a hedge against drought risk.

The Energy Intensity of Water Supplies

Every source of water has a different energy intensity. Figure 2-2 shows the relative energy intensity of water supply options for one Southern California regional water and wastewater utility, the Inland Empire Utilities Agency (IEUA).

[14] An aquifer is a body of permeable rock that can contain or transmit water.

Figure 2-2 Energy Intensity of IEUA Water Supply Options



Source: Dr. Robert Wilkinson, Environmental Studies Program, University of California, Santa Barbara, and Martha Davis, IEUA.

Of the above IEUA options, the East Branch State Water Project source is second only to ocean desalination in energy intensity. Recycled water is the least energy-intensive supply option. The relative energy intensity of supply options varies for each water utility, depending upon the nature and characteristics of its water supplies.

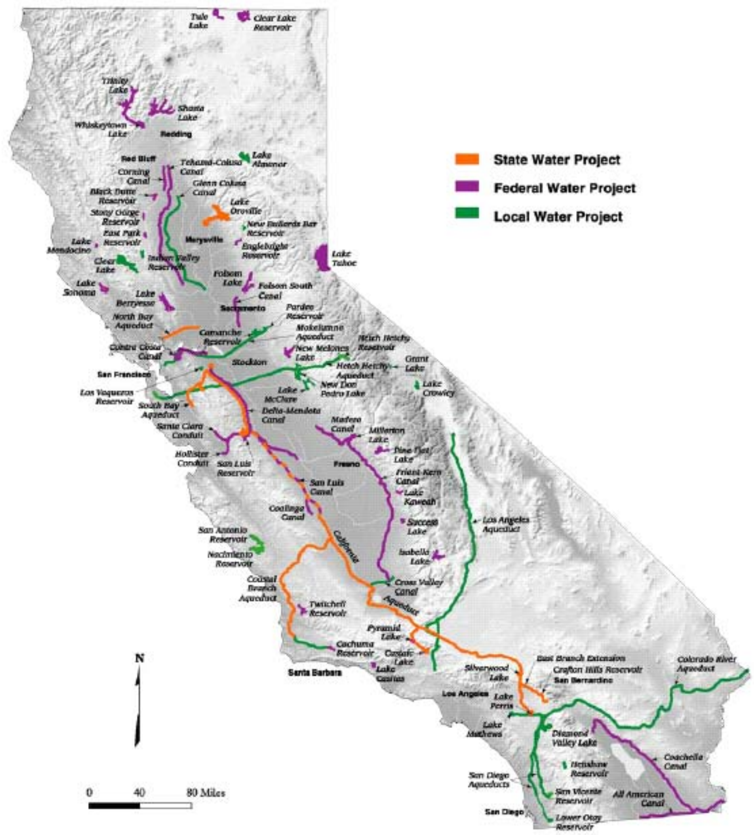
The sections below describe the relative energy intensities of various water supply sources. This concept is important to the discussions in the following chapters since the energy intensity of supply is the most significant sector in which near-term action can positively affect the state's energy circumstances.

Surface Water

The energy intensity of surface water supplies is mainly in the conveyance of raw water for either agricultural and some industrial uses or to treatment facilities for potable urban water use.

California's water supply varies significantly with annual and seasonal hydrological conditions, as well as geography and topography. The major water sources are in Northern California, while the major urban centers and agricultural lands are in the Northern Bay Area, Central Valley, and Southern California. Surface water conveyance systems were built to balance statewide water supplies with demands. These conveyance systems were designed to move water to areas of need outside the basin in which water is collected. This process – known as "interbasin transfers" – accounts for most of the energy embedded in California's surface water supplies. The energy intensity of various interbasin transfers depends on the distance and elevation over which the water must travel. The map in Figure 2-3 shows the state's interbasin transfer systems.

Figure 2-3 Interbasin Transfer Systems in California



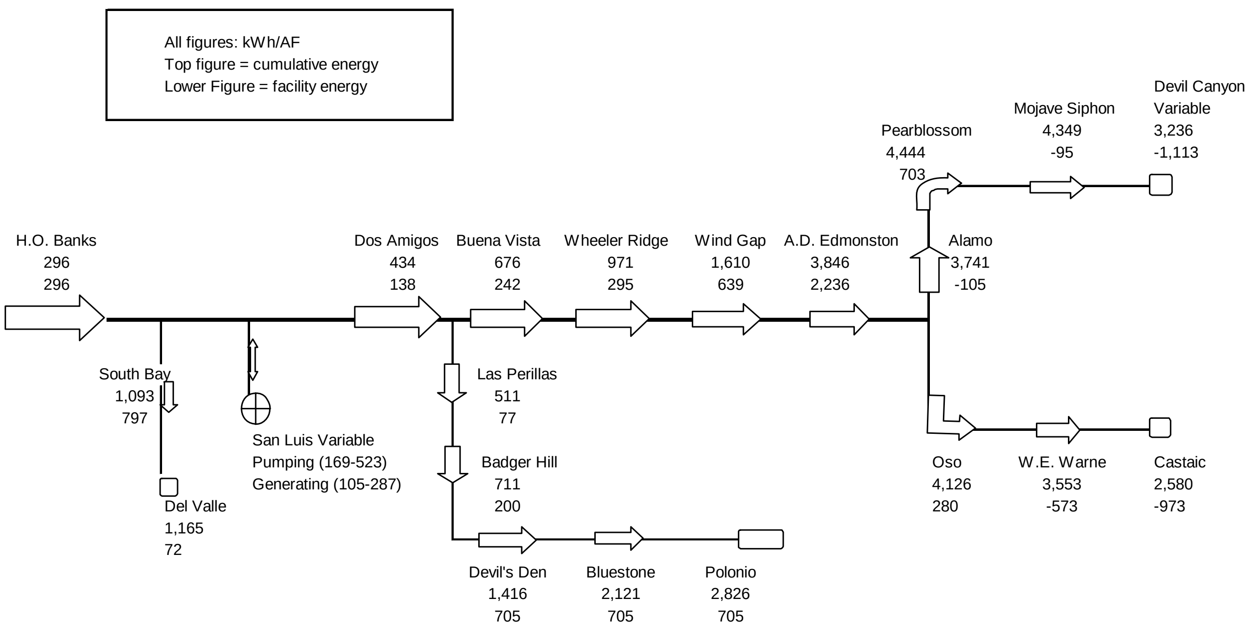
Source: *2005 State Water Plan Update*, DWR.

It is the pumping of this water that accounts for the relative energy intensities of different surface water sources. Note that some systems originate in mountain ranges and use gravity to naturally deliver water to points of need. These systems use very little energy. Other systems must transport water long distances on relatively flat valley floors. The State Water Project must also pump water more than 3,000 feet over the Tehachapi range to reach end users in Southern California.

SWP, the largest state-built multipurpose water project in the U.S., was planned, designed, built, and is now operated and maintained by the DWR. The SWP was constructed for the primary purpose of transporting water from Northern California to arid areas, both agricultural and urban, in Central and Southern California. The SWP delivers water to 29 water agencies and irrigation districts, which then distribute the water to 20 million people and 900,000 acres of crops. SWP water is distributed about 50/50 to agricultural and urban water uses.[15]

The elevation diagram below (Figure 2-4) illustrates the relative energy intensity of delivered SWP water at various points along the California aqueduct. The numbers are shown in kilowatt-hours per acre-foot (kWh/AF). They include transmission losses and, where applicable, energy recovery.

Figure 2-4: State Water Project Pumping Energy



Source: Dr. Robert Wilkinson, PhD, University of California, Santa Barbara, based on DWR data.

Depending on the point at which SWP water is delivered, the embedded energy may range from a low of 676 kWh/AF (676 x 1,000,000 gallons/325,851 gallons/AF = 1,330 kWh/MG) at Dos Amigos, to a high of 3,236kwh/AF (9,930 kWh/MG) at Devil Canyon.

Many of the state's interbasin transfer systems also have significant hydroelectric generation. The Central Valley Project, the East Bay Municipal Utility District's (EBMUD) Mokelumne Aqueduct, and San Francisco's Hetch Hetchy Regional Water System, are all net energy producers. Despite its significant hydroelectric capacity, the State Water Project is a net energy consumer. The Colorado River Aqueduct is also a net energy consumer in California, although the project itself includes significant federal hydroelectric projects on the Colorado River.

[15] Presentation by Bill Forsythe, DWR, to Committee Workshop January 14, 2005.

Groundwater Sources

Groundwater supplies about 30 percent of the state's water needs on average but as much as 60 percent during times of severe drought.

Several hundred million acre-feet of water are stored in 450 groundwater aquifers in the state, compared with approximately 45 million acre-feet in California's 1,200 surface water reservoirs.[16] These aquifers are recharged either naturally or artificially. Natural recharge generally consists of runoff that percolates into the soil, or migration of surface water through a lake or streambed. Almost all of the 450 groundwater aquifers in the state are in decline or overdrafted, forcing users of that water to pump from greater and greater depths, requiring greater amounts of energy in the process.

The process of artificially storing groundwater for future withdrawal is known as aquifer storage and recovery (ASR). Closely related to ASR are "conjunctive use" and "artificial recharge," terms that are often used interchangeably. Water agencies around the state store water in aquifers for both daily and seasonal use and for emergency drought supplies. In general, surplus water is pumped into wells or allowed to percolate into aquifers from ponds and lakes, then pumped from wells when needed.[17]

Less is known about groundwater than about any other water source. This is because each groundwater basin is unique and production characteristics of wells are often interlinked. Since groundwater use is largely unregulated, the actual quantity of energy used for groundwater pumping statewide is also not readily determinable.[18]

In a 2003 study, the Electric Power Research Institute (EPRI) estimated national averages ranging from 700 to 1,800 kWh/MG, depending on use and customer sector.[19] Dr. Robert Wilkinson, director of Water Policy Program at the Bren School of Environmental Science and Management, University of California, Santa Barbara, estimated 2,915 kWh/MG, for groundwater pumping in the Chino Basin.[20] This number reflects the fact that the groundwater aquifers in Southern California, where the Chino Basin is located, are relatively deep compared to those in the northern and central part of the state.

---

[16] ACWA Water Facts website.
[17] USGS 2005, Introduction to Aquifer Storage and Recovery, [http://ca.water.usgs.gov/issues/6.html].
[18] Hundreds of thousands of groundwater wells are privately owned, and serve residences, farms, businesses, and small water systems. The electricity used for pumping from private wells is often not separately metered and is not captured in the Energy Commission's and electric utilities' energy use data.
[19] "Water & Sustainability (Volume 4): U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century", EPRI Topical Report, March 2002.
[20] Dr. Robert Wilkinson's presentation to the January 14, 2005 *Energy Report* Committee workshop.

It is reasonable to expect wide variability in the energy intensity of different groundwater sources, depending upon both the depth at which the groundwater resides and the efficiency of the pumps and motors used to pump it. In the context of energy intensity and benefits to the state, the primary benefit of groundwater is its ability to offset the high energy intensity of SWP deliveries in the fall. In Southern California, some water agencies already pump groundwater during the summer and recharge aquifers with SWP imports during the non-summer months. Even at the upper end of energy intensity, using local groundwater supplies to defer summer deliveries of SWP water to Southern California results in significant energy and reliability impacts for the state overall.

Ocean and Brackish Water

Treating ocean or brackish water -- desalination -- began in California in 1965. In 1999, there were 30 desalting plants operating in California for municipal purposes, with total capacity of 80,000 acre-feet per year. Table 2-1 illustrates the expected growth in desalination in California.[21] If all of the planned new capacity is built, total production of desalination will increase from about 80,000 acre-feet per year to nearly 600,000 acre-feet.

Table 2-1: Desalting in California for New Water Supply

	Plants in Operation		Plants in Design & Construction		Plants Planned or Projected	
Feedwater Source	No. Of Plants	Annual Capacity	No. Of Plants	Annual Capacity	No. Of Plants	Annual Capacity
Groundwater	16	79,100	6	29,500	6	61,700
Seawater	7	1,500	1	300	13	415,100
Total	23	80,600	7	29,800	19	476,800
Cumulative			30	110,400	49	587,200

1. Capacity in Acre-feet per year. No. of Plants is the number of new plants.
2. Design & Construction – Construction underway or preparation of plans and specifications has begun for new plants or plant expansions.
3. Planned – Planning studies underway for new plants or plant expansions.
4. Projected – Projected new plants or plant expansions.
5. Sources: “Water Desalination Report” and Worldwide Desalting Plants Inventory series by International Desalination Association as cited in the DWR Bulleting 160-05.

Source: 2005 State Water Plan Update, DWR

[21] *California Water Plan Update 2005* Volume 2, Resource Management Strategies, Chapter 6 Desalination.

Recycled Water

The fastest growing new source of water in the state is not a new source at all; it's recycled water from wastewater systems, commonly referred to as reclaimed water or reuse. Californians have used recycled water since the late 1800s. Faced with increasingly stringent requirements governing disposal of wastewater and limited water supplies, many agencies are installing additional treatment facilities that can purify wastewater to the point where it can be substituted for fresh water in many applications, including power plant cooling and landscape irrigation.

The primary benefit of increasing the use of recycled water, from an energy perspective, is the displacement of other, more energy-intensive water supplies.

- By using local recycled water to recharge depleted groundwater aquifers in Southern California, the amounts of energy-intensive seawater desalination and SWP imports could be reduced.

- When recycled water is distributed to local end users for landscape irrigation, significant energy savings accrue:

  - First, from displacing the energy intensity of the highest marginal water source.

  - Second, from avoiding the energy used to treat the water unnecessarily to potable water standards.

Since recycled water is often a by-product of existing secondary and tertiary wastewater treatment processes, it is the least energy-intensive source in the state's water supply. While incremental energy is typically required to pump recycled water uphill to redistribute it to end users, this incremental energy is offset in part or in whole by displacing higher energy intensity water supplies, as well as reducing potable water treatment and distribution.

The actual net energy benefit of any proposed project also needs to consider the incremental energy that might be needed to treat the wastewater to higher standards than normal, such as targeted end use water quality requirements. Table 2-2 describes the level of treatment needed for different types of reuse.

Table 2-2: Demand Sectors and Minimum Treatment Levels

Demand Sectors and Examples of Minimum Treatment Levels for Specific Uses to Protect Public Health

Types of Use	*Treatment Level*		
	Disinfected Tertiary	*Disinfected Secondary*	*Undisinfected Secondary*
Urban Uses and Landscape Irrigation			
Fire protection	☑		
Toilet & urinal flushing	☑		
Irrigation of parks, schoolyards, residential landscaping	☑		
Irrigation of cemeteries, highway landscaping		☑	
Irrigation of nurseries		☑	
Landscape impoundment	☑	☑*	
Agricultural Irrigation			
Pasture for milk animals		☑	
Fodder and fiber crops			☑
Orchards (no contact between fruit and recycled water)			☑
Vineyards (no contact between fruit and recycled water)			☑
Non-food bearing trees			☑
Food crops eaten after processing		☑	
Food crops eaten raw	☑		
Commercial/Industrial			
Cooling & air conditioning - w/cooling towers	☑	☑*	
Structural fire fighting	☑		
Commercial car washes	☑		
Commercial laundries	☑		
Artificial snow making	☑		
Soil compaction, concrete mixing		☑	
Environmental and Other Uses			
Recreational ponds with body contact (swimming)	☑		
Wildlife habitat/wetland		☑	
Aquaculture	☑	☑*	
Groundwater Recharge			
Seawater intrusion barrier	☑*		
Replenishment of potable aquifers	☑*		

*Restrictions may apply

Source: DWR's Water Facts 23 issued October 2004.

In most circumstances, from an energy perspective, recycled water made as a by-product of the wastewater treatment process is the most preferred option. Primary barriers to increasing the use of recycled water include the incremental cost of dual piping systems to deliver this source of non-potable but usable water and public apprehension about using water recovered from the sewage treatment process.

The Energy Intensity of the Water Resource Portfolio

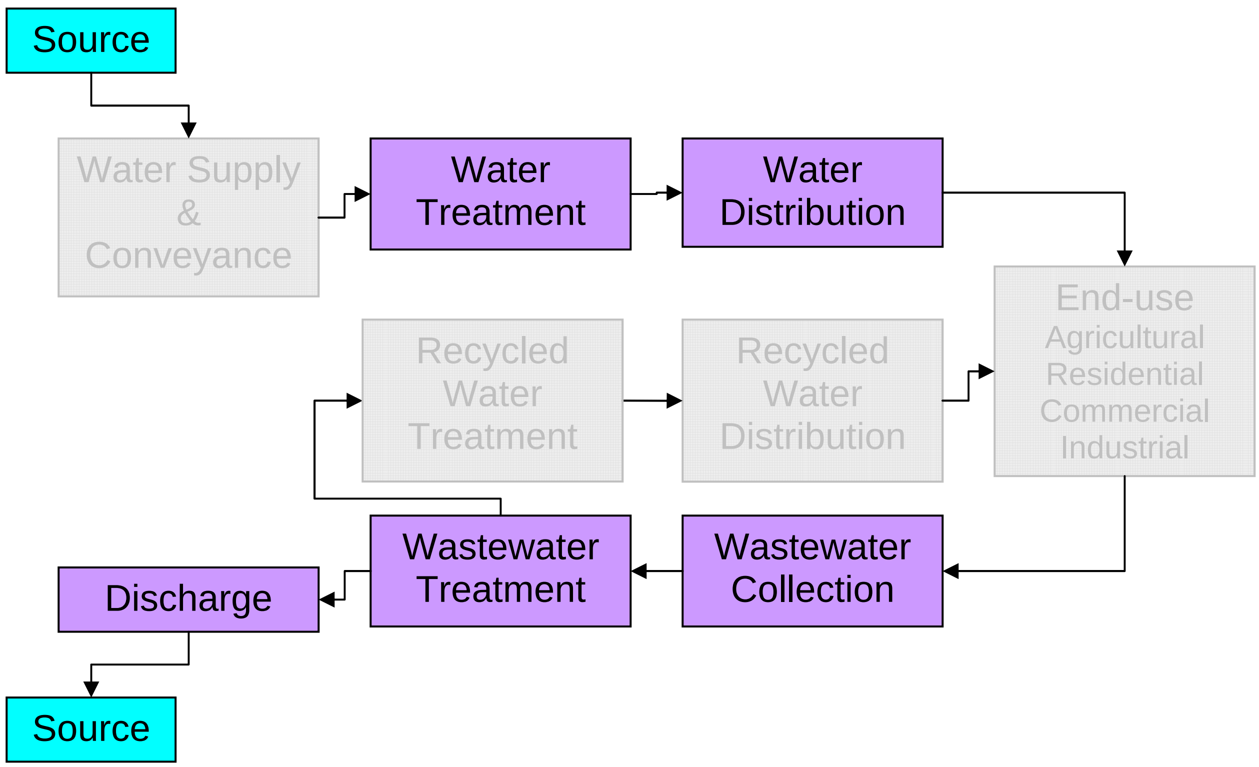
Ultimately, all of these resource choices come together in a water utility's water resource portfolio. Similar to energy utilities, water utilities conduct integrated resource planning (IRP) on a "least cost/best fit" basis. Since energy is typically the highest cost of water supply resources, embedded energy in delivered water supplies is generally reflected in the preferred loading order of water resources in the state's *2005 Water Plan Update.* Using water more efficiently frees up current resources to meet some of the future demand growth.

This is particularly critical in Southern California, where its water mix is roughly half from local sources, and half from imported sources. While water utilities are working hard to develop more local supplies and improve water use efficiency, there are not many options to develop new water sources. Presently, the primary available options are recycled water and seawater desalination.

CHAPTER 3 – WATER AND WASTEWATER TREATMENT AND DISTRIBUTION

This section will discuss, due to their similarities, both the energy intensity of potable and waste water treatment and distribution and the distribution of recycled water.

Figure 3-1: Water Use Cycle – Treatment and Distribution



Energy use for water distribution loads is primarily for pumping water and maintaining sufficient pipe pressure to assure that flows can be made at scheduled rates while maintaining sufficient pressure for fire service.

Water and wastewater treatment processes also use large quantities of energy. In water treatment, energy requirements depend primarily on the characteristics of the raw water, plant size, treatment process, and the distance and elevation of the treatment plant in relation to water sources and water distribution systems. In wastewater treatment, the characteristics of the influent and the level of treatment (primary, secondary or tertiary) are principal drivers of energy consumption.

Electric loads at water and wastewater treatment plants consist primarily of pump motors but also include air blowers, injection equipment, controls, lighting, and, in some cases, ultraviolet light disinfection and ozonation. Wastewater treatment plants also require activated sludge and sludge handling systems that consume large quantities of energy. The Energy Commission Demand Office estimates that a total of about 9,000 GWh of electricity is used annually by both water and wastewater facilities. This is based on both electric and water meter data and assumptions from engineering handbooks and other sources about the electricity use of certain equipment. Because the meter data is not reported in separate categories it cannot be disaggregated to separate water from wastewater treatment.

The Association of California Water Agencies (ACWA) estimates that the state's water and wastewater treatment facilities collectively draw about 3,000 MW at peak, with 1,800 MW occurring in Southern California Edison's (SCE) service territory, with the rest geographically distributed throughout the state more or less in proportion with population.

Both water and wastewater treatment processes require pumps and motors to transport water before, during, and after treatment. Pumping is not as significant a portion of the load for wastewater as for water because wastewater treatment processes are significantly more energy intensive, and both wastewater collection and disposal typically rely heavily upon gravity. Thereafter, the treatment processes and their relative energy intensities vary considerably.

Water treatment has historically been a comparatively modest user of energy, relying primarily upon settlement and passive filtration to remove particles from water, and chemical treatment (chlorination or chloramination) for disinfection. As new water quality regulations are implemented, energy-intensive technologies such as membranes, UV and ozonation will require large quantities of energy. Wastewater treatment requires much more energy, with each progressive level of treatment requiring still more. In secondary treatment, most of the energy is used for biological treatment; pumping of wastewater, liquid sludge, biosolids and process water; and processing, dewatering, and drying of solids and biosolids. Tertiary treatment requires additional energy for aeration, pumping, and solids processing. All of these processes present opportunities for energy reduction.

To reduce energy costs, many utilities have already replaced pumps and motors with newer, more efficient equipment. The addition of variable frequency drives and customized pumping algorithms provide the capability to further reduce energy requirements by more closely matching pumping capacity with loads. In addition, both water and wastewater utilities have recently demonstrated that significant reductions in energy consumption could be achieved by employing interim storage to shift processing to off-peak periods and balance processing loads among multiple plants to optimize plant efficiencies.

In the mid-1990s, EPRI and HDR Engineering, Inc. conducted an audit of the energy savings potential for water and wastewater facilities in California. At that time, they estimated that more than 880 million kWhs could be saved by implementing several measures: load shifting, variable frequency drives, high-efficiency motors and pumps, equipment modifications, and process optimization with and without Supervisory Control and Data Acquisition (SCADA) systems. These estimates did not include incorporating interim storage to shift loads and optimize plant efficiencies. Industry experts estimate that untapped energy efficiency opportunities through the optimization of water and wastewater treatment processes could be as high as 30 percent of existing processes.

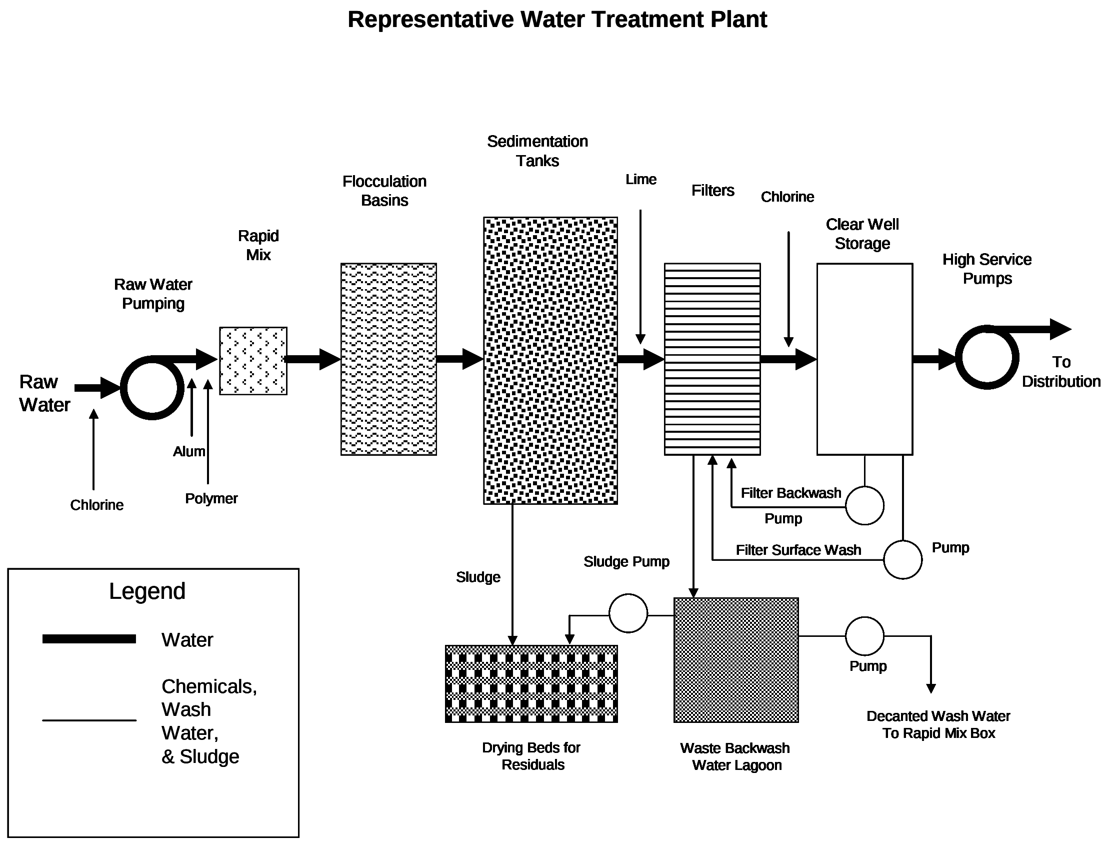
The sections below will describe energy uses for water treatment and distribution, and for wastewater treatment.

Water Treatment

Source water quality and the end use of the water dictate the level of treatment required. For potable uses, a typical sequence of operations for surface water treatment is described in the following steps (refer to Figure 3-2).

- Raw water is first screened, pre-oxidized using chlorine or ozone to kill organisms.
- Alum and/or polymeric materials are added to the water.
- Flocculation and sedimentation remove finer particles.
- A second disinfection step kills remaining organisms.
- The clear tank allows contact time for disinfection.
- Treated water is distributed to consumers by high-pressure pumps (disinfectant residue is carried into the distribution system to prevent organism growth). Sludges and other impurities removed from water are concentrated and disposed of.

Figure 3-2: Sequence of Operations in Surface Water Treatment



Source: Electric Power Research Institute

As shown in Table 3-1, although no two treatment facilities are identical, the following survey of more than 30,000 public supply systems in the United States[22] indicates little variation in water treatment energy intensity for plant capacities of at least 1 million gallons per day[23].

[22] Inventory of public water supply systems maintained by the U.S. Environmental Protection Agency in the Safe Drinking Water Information System.
[23] *Water & Sustainability* (Volume 4): *U.S. Electricity Consumption for Water Supply & Treatment*, EPRI March 2002, Figure 2-1, page 2-2,

Table 3-1 Energy Use by Surface Water Treatment Plants

Plant Size (Million Gallons per Day)	Energy Intensity (kWh/MG)
1	1,483
5	1,418
10	1,406
20	1,409
50	1,408
100	1,407
Average	**1,422**

Source: Electric Power Research Institute

Water treatment energy requirements are driven principally by the characteristics of incoming raw water and by the distance and elevation of the treatment plant in relation to water sources and the distribution system. Actual energy demand is highly variable by water utility. Lowest is pristine Hetch Hetchy water, which is exempted from filtration by the U.S. Environmental Protection Agency (US EPA)[24]. However, most surface and groundwater sources require treatment to meet regulatory standards and the taste and odor preferences of the public. Some treatment plants also have unique requirements, such as the removal of industrial chemicals from well water that require more energy. Net energy demand is expected to change as more energy-intensive disinfection processes are used to address water quality concerns and meet increasingly stringent potable water rules under the federal Safe Drinking Water Act (see discussion in Chapter 6).

Despite extensive data searches, staff found only a few studies that attempted to determine the exact electricity use for water treatment facilities. One of the most comprehensive and innovative studies came from an effort in Sonoma County to address greenhouse gas emissions. This study included energy use by municipal facilities, including the county's wholesale water agency, the Sonoma County Water Agency, and all of its municipal system water customers.

The Sonoma County Water Agency provides domestic water to 540,000 domestic water users in Sonoma, Marin, and Mendocino counties. Its only source of water is the highly variable flow of the Russian River and storage in two reservoirs on tributaries of the Russian, Lake Sonoma, near Healdsburg, and Lake Mendocino, near Ukiah. The EPA has listed the Russian River as impaired because of dissolved solids and nutrients. To both avoid these impairment issues and comply with federal

[24] The high quality Hetch Hetchy's water supply, produced by Sierra snowmelt in a protected watershed, has been granted a filtration exemption from the U.S. Environmental Protection Agency (U.S. EPA) and the California Department of Health Services (DHS).

Endangered Species Act limitations on stream withdrawals, many of the county water agency's municipal customers mix the river water with about equal amounts of groundwater, which is generally less costly.

The Sonoma County Water Agency required nearly 2,600 kWh/million gallons to pump and treat water from the river over the period of April 2000 to September 2002. Pumping costs were essentially linear throughout the year (that is, the electricity use per million gallon rate was essentially constant) except for spikes in January and February, when large amounts of surplus water were transferred to storage in reservoirs, especially in Marin County (Rosenblum 2003). Data are insufficient to determine the amount of energy used for pumping the water (which corresponds to the "Collection, Extraction and Conveyance" portion of the water use cycle described in Chapter 2) as opposed to energy used solely for water treatment.

In addition to Hetch Hetchy, EBMUD is an example of an agency with energy intensity of water treatment on the lower end of the spectrum. EBMUD gets 95 percent of its water from the Mokelumne River, delivered by gravity through the Mokelumne Aqueduct. The Mokelumne water is relatively high quality at its source, requiring little treatment; and the EBMUD's treatment facilities are located high in the East Bay Hills, using elevation to help pressurize its distribution system. Because of these factors, EBMUD's electricity use is a low 150 kWh/million gallons for conveyance, and 275 kWh/million gallons for treatment (EBMUD 2000 and Navigant Consulting 2004).

Desalination

Desalination involves removal of salts and dissolved solids from seawater or brackish water. Most desalination processes are based on either thermal distillation or membrane filtration technologies, both of which are very energy intensive.

The primary benefit of desalination is its ability to increase potable water supply by reclaiming water of poor quality. The most significant challenge of desalination is that it is a very energy-intensive source of water, and its highest use will likely coincide with extended drought periods when hydropower production is lowest.

Unlike every other type of water facility, where staffing edges out energy use as the main expense, desalination's primary operating cost is for energy, with seawater desalination being considerably more energy intensive (9,780-16,500 kWh/million gallons) than brackish groundwater desalination (3,900–9,750 kWh/million gallons).[25] The difference between seawater and brackish desalination ranges is due primarily to the difference in the initial water quality, and within each range the variance is due primarily to the plant design and technology employed. Most desalination plants operate continuously, so this electricity is used during all seasons and at all times of

[25] California Department of Water Resources Desalination Task Force Final Report 2003.

the day. Current plants are operating 90 percent of the time, with downtimes only for maintenance (DWR, 2005).

According to the *2005 Water Plan Update*, a 50 MGD seawater plant (approximately 50,000 acre-feet per year, or 16.25 billion gallons, assuming operations 90 percent of the time) would require about 33 MW of power.[26] This translates to about 5,200 kWh per acre-foot, or 16,000 kWh per million gallons, which is the upper-end of California's energy intensity of water supplies. Multiple efforts are underway to increase the energy efficiency of desalination through improved membranes, dual pass processes, and additional energy recovery systems.

Present estimates indicate that existing desalination facilities use 370-890 GWh per year. As stated in Chapter 2, if all of the planned new capacity is built, total production of desalination will increase from about 70,000 acre-feet per year to nearly 300,000 acre-feet. Assuming an average of 3,900 kWh/acre-foot (about 12,000 kWh per million gallons),[27] an incremental 230,000 acre-feet would require about 897 GWh. In the IEUA example, desalination of local brackish groundwater supplies can produce a net energy benefit when displacing higher energy intensity desalted seawater or SWP imports.

Desalination of seawater has the highest energy intensity of all water treatment options.

Water Distribution

Once treated to potable standards, the water must be distributed to customers, generally through a network of storage tanks, pipes, and pumps. During distribution, water must be kept moving and under pressure to minimize corrosion and biological contamination. Storage tanks and water mainlines must be flushed periodically to prevent oxidation and control biofilms (AWAARF 2000). Even the farthest reaches of the network must be kept under adequate pressure and constantly flushed since low pressure and low flow allow microbes to flourish (ACWA workshop April 14, 2005).

On average, staff estimates that city water agencies use about 1,150 kWh/million gallons of electricity just to deliver water from the treatment plant to their customers. The energy required for distribution pumping is mainly driven by the distribution system configuration, its relative size, elevations, and system age.

The water supply diagram and the results of the EPRI survey in Table 3.1, above, reflect little variation in the amount of energy required to treat and distribute a unit of water for systems requiring at least 1 million gallons per day. For this large survey

---

[26] *California Water Plan Update 2005* Volume 2, Resource Management Strategies, Chapter 6 – Desalination.

[27] The average of the Chino desalter and seawater desalination in IEUA's water supply options.

size of approximately 30,000 public water supply systems, distribution pumping of treated water remained fairly constant at between 80 to 85 percent of total energy requirements when treatment and distribution energy loads are combined. For purposes of this paper, staff adopted this ratio and assumed prototypical water distribution energy intensity to be about 1,200 kWh/MG.

Cities with hilly terrains can use hilltop tanks both as storage and to provide pressure into the distribution system; San Francisco is perhaps the best example of this, serving virtually all of its customers from hilltop tanks. But the water must first be pumped up to the tank, often several hundred feet in elevation. In addition, though water agencies loathe wasting water and energy, they often must flush water from the tanks to prevent microbial contamination and then fill them up once again through the pumping station. In fact, this flushing accounts for the bulk of electricity used in EBMUD's distribution system.

Wastewater Treatment

Other than water devoted to landscape irrigation, or lost through evaporation (such as in cooling towers and other processes), almost all the water entering homes and businesses in California eventually leaves as wastewater. Wastewater treatment is similar to freshwater treatment. But most wastewater treatment systems have the additional step of using biological reactors that use bacteria to break down waste. Wastewater pumps are inherently more inefficient because they must pump both liquids and solids, and must have greater clearances between the pump impeller and the casing, allowing much of the pumped water to return to the intake plenum. Energy use in a wastewater system is primarily from use of very large electric pumps and blowers and use of natural gas to heat the anaerobic digesters.

Digester biogas (approximately 60 percent methane and 40 percent CO_2) is produced by anaerobic bacteria. The gas can be collected and used to generate electricity, usually powered by an internal combustion engine and used to run the facility itself. Waste heat recovered from the engine can be used to heat the digesters and displace natural gas use.

The number of water and wastewater treatment techniques and the combinations of techniques are expected to increase over time as more complex contaminants are discovered and regulated.

Wastewater consumes electricity in three stages: transport to the facility, treatment, and disposal/recycle. The first stage, transporting from the customer to the wastewater treatment facility, requires about 150 kWh/million gallons of electricity on average to pump the water, depending on topography, system size, and age. When they have a choice, agencies prefer to place water treatment facilities above their customers and the wastewater treatment facilities below, to harness the pull of gravity where possible, and to place water intakes above wastewater outfalls on rivers.

There are levels of treatment, and each progressively requires higher levels of energy use. These steps may consist of physical processes, biological processes, or chemical processes.

Physical Processes
The initial steps involved in the sewage wastewater treatment are physical processes, which separate larger solids from liquid using screening or grit removal. Steps that remove larger solids are termed preliminary treatment. The solids separated from the preliminary processes are usually disposed of in a landfill. After removal of larger solids, primary treatment follows to separate the smaller solids. Some chemicals may be added to assist with solids removal.

Biological Processes
The physical processes are followed by biological aerobic treatment in which extended aeration (oxygen) and environmental conditions are provided for microbes to break down organic material into carbon dioxide and water. Equipment used for the aerobic treatment includes tricking filter, aeration basin, and others. This biological aerobic treatment is commonly called secondary treatment.

After the aerobic treatment, the wastewater is separated with a sedimentation tank to separate the sludge and the clear effluent. The sludge is then sent to an anaerobic digester where the organic material is broken down into biogas, which is primarily methane and carbon dioxide.

Chemical Processes
The clear effluent, after the secondary treatment is further treated with physical filtration, chemical, or ultraviolet disinfections. This further treatment is commonly called tertiary treatment. The tertiary effluent can be used for beneficial reuse or discharged to surface water.

The progressive levels of treatment are commonly referred to as “primary”, “secondary” and “tertiary”, with primary being the lowest level, and tertiary the highest. Effluent from both secondary and tertiary treated water can be reused. The levels of treatment required for types of reuse (i.e., recycled water) are described in Table 2-2 in Chapter 2.

The major driver of unit energy consumption is the degree of treatment required. As noted above, there has been a trend toward more thorough treatment, with upgrades or replacements of older systems that could not provide this higher level of treatment. This trend is seen in comparing the estimated unit electricity consumption in 1988 with consumption in 2000: the baseline unit energy consumption was estimated to increase at an average compound rate of about .08 percent per year. This upward trend in unit electricity consumption is expected to continue as more thorough treatment is required.

Unlike water treatment and distribution systems, unit volume energy requirements for wastewater treatment plants vary greatly depending upon plant size. Energy intensity for a 1 MGD wastewater treatment plant can be approximately three times that of a 100 MGD wastewater treatment plant[28]. As expected, unit electricity consumption rises as the degree of treatment and complexity of the process increases. For example, advanced wastewater treatment with nitrification is three times as energy intensive (due to additional pumping requirements) than that of a relatively simple trickling filter plant.[29] Further complicating the assessment of prototypical unit volume energy intensity are unique operational environments, discharge limitations, influent characteristics, permitted effluent limitations, and variations in plant permitting cycles.

Table 3-2 Energy Intensity of Wastewater Treatment Facilities

Source of Data	**kWh/MG**
Inland Empire Utilities Agency	2,971
City of Santa Rosa	2,920
East Bay Municipal Utilities District	2,001
Metropolitan Water District	2,655
Methodology for Analysis of Energy Intensity in California's Water Systems	1,911
Energy Down The Drain, The Hidden Costs of California's Water Supply	2,302
Energy Benchmarking Secondary Wastewater Treatment	2,625

Source: Multiple, see Appendix C

Table 3-2 shows wastewater treatment plant energy intensities reflecting a range of energy intensity for facilities operating in California and cited in studies. Based on this range, 2,500 kWh/ MG has been adopted as the prototypical wastewater treatment energy intensity (for more detailed discussion and references see Appendix C).

One of the most interesting opportunities for reducing energy use for wastewater treatment is to improve storm water management. During rainy weather, a considerable amount of runoff ends up in wastewater systems, greatly increasing treatment costs. Even communities that do their best to keep stormwater out of their sewer systems see nearly double the flow during a winter storm than during the dry summer months. This “infiltration/inflow” of stormwater into the sewer system has on

[28] *Water & Sustainability* (Volume 4) *U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century*, EPRI 2002, Pages 3-4 & 5 and Table 3-1.
[29] *Water & Sustainability* (Volume 4) *U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century*, EPRI 2002, Pages 3-4 & 5 and Table 3-1.

occasion forced many communities to discharge raw or minimally treated wastewater directly into local waters.

For example, Sonoma County's largest wastewater facility, the Laguna Wastewater Treatment Plant, operated by the City of Santa Rosa, experienced a peak inflow of nearly a billion gallons per month in January and February of 2000 and 2002, while average inflow in the summer months was just over half that amount (Rosenblum 2003, Figure 7). Its wastewater treatment electricity use is proportionate to these flows, and therefore nearly twice as high in winter than in summer.

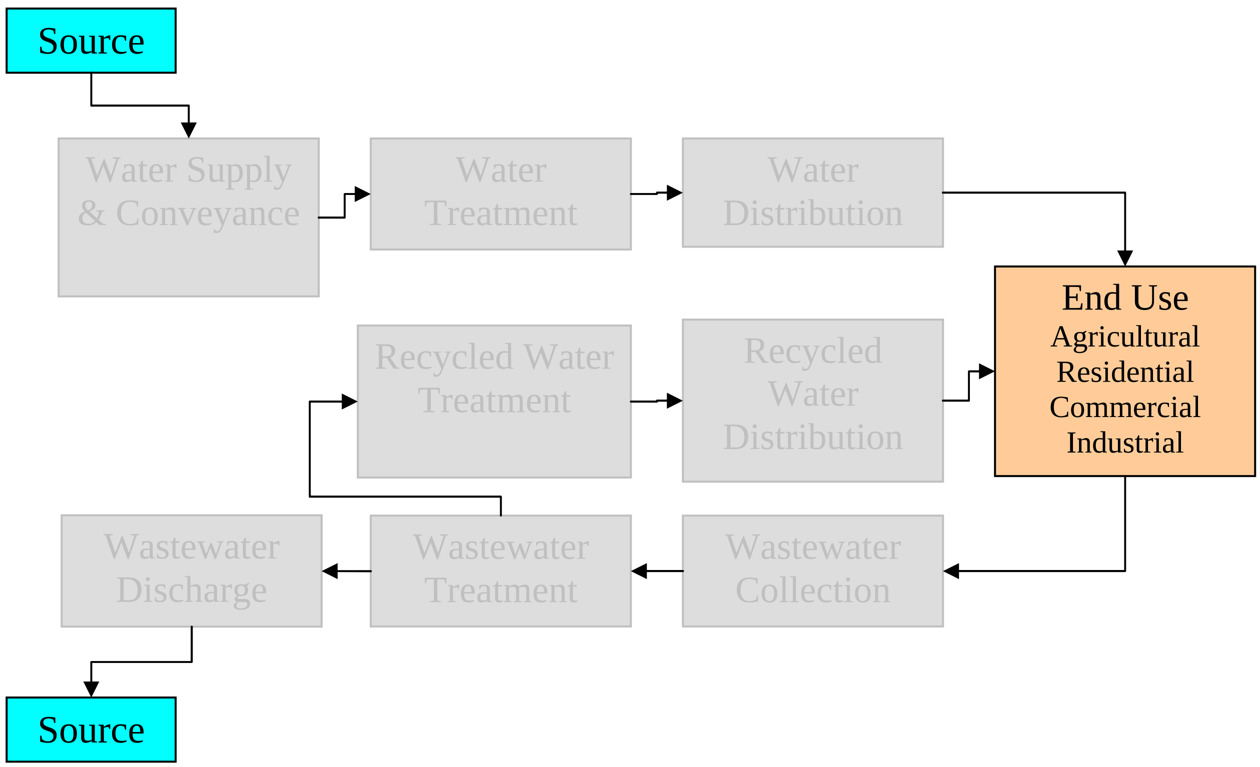
Conclusions

In this chapter, staff has generally described water energy intensity for water treatment, wastewater treatment, and water distribution. Staff has also identified areas that will require additional information and analysis to better understand these systems and how modifications or improvements could benefit the energy sector. Future regulatory changes made in response to health and water quality concerns will affect the overall energy demand of these systems.

CHAPTER 4 – WATER RELATED END-USE EFFICIENCY

This chapter addresses opportunities to increase water and energy end-use efficiency.

Figure 4-1: Water Use Cycle – End Use



The Energy Impact of Water Use Efficiency

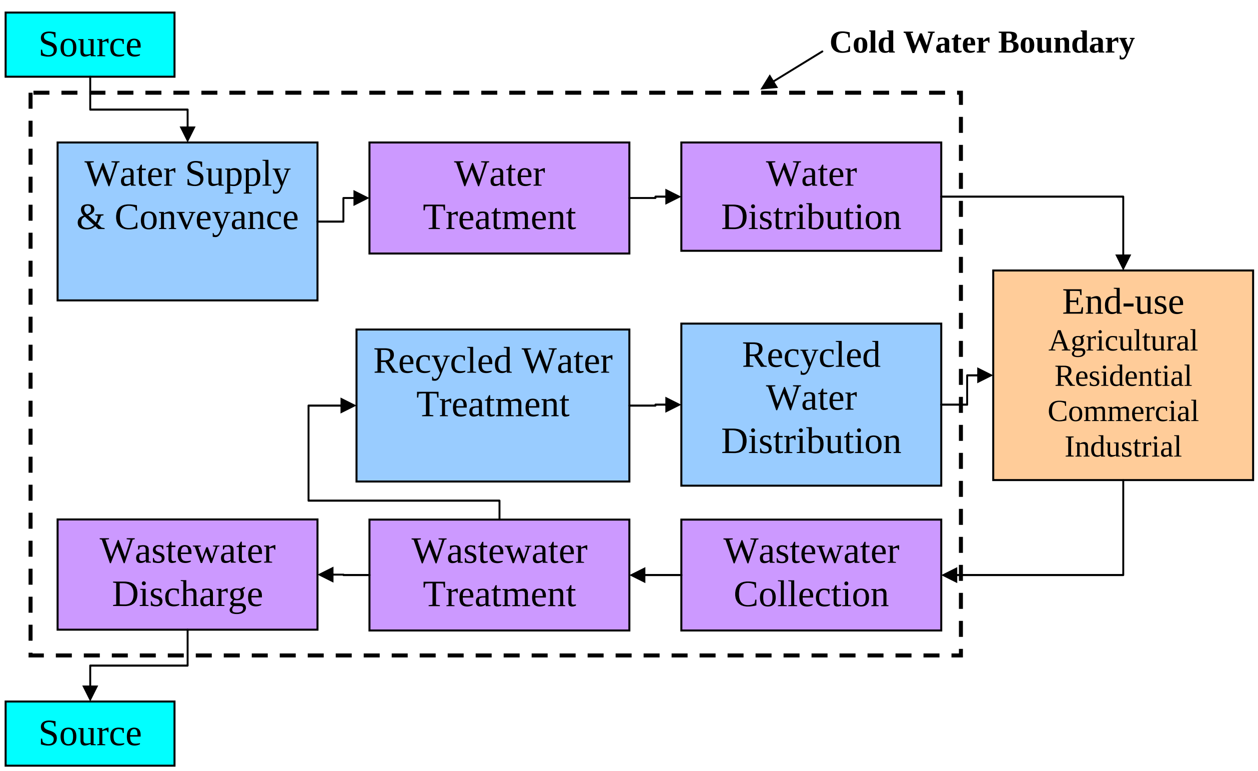
Water end-use applications in California use more energy than any other part of the state's water use cycle. Energy efficiency water programs have traditionally focused on either saving energy in water and wastewater treatment facilities or saving energy in end-use applications including water heating, clothes washing and drying or process heating. Water use efficiency programs have similarly focused on saving water in end-use applications. In both cases, end-use efficiency measures are beneficial, to both utilities and end users, when the value of the saved energy or water exceeds the cost of the measure.

For the most part, these efficiency improvements have been pursued separately by water and energy utilities, although there are some examples of close coordination, including the effort to introduce high-energy-efficiency and low-water-factor clothes washers to the consumer market. What appears to be missing is the recognition that saving water also saves energy throughout the conveyance, treatment, distribution and wastewater treatment processes of the water use cycle.

The energy intensity of water use varies depending on its end use and location in the state. For example “statewide average,” agricultural end uses are less energy-intensive than either “statewide average” urban end uses or agricultural end uses in Southern California that rely upon SWP or Colorado River Aqueduct water deliveries. All are more energy-intensive than those in Northern California. On average, urban water uses in Southern California are more than three times as energy-intensive as those in Northern California.

While these relationships are useful for policy development and planning, it is important to recognize that the actual energy intensity of the water use cycle is very location- and application-dependent; this information is important as specific projects are considered. Figure 4-2 shows the overall cold water boundary. To apply the concept of energy intensity, the cold water boundary must be identified for specific locations and applications. Further details are in Appendix C.

Figure 4-2 Cold Water Boundary in the Water Use Cycle



Conserving a unit of cold water avoids using the energy that would have been needed to supply, treat, deliver, consume, collect, treat, and dispose of it as wastewater. The actual amount of energy saved depends upon the type and source of water supply, the distance the water has to travel, the nature and extent of its treatment, and the type of end use.

In California, saving cold water, both indoors and outdoors, saves energy. The energy saved is primarily electricity. Saving outdoor water saves the energy it takes to extract, convey, treat, and distribute water to customers. Saving indoor water saves the additional energy, again mostly electricity, used to collect, treat and dispose of the waste water. Saving indoor hot water saves the additional energy needed to heat this water. In California, this additional energy is mostly in the form of natural gas.

From an energy perspective, saving cold outdoor water is good. Saving cold indoor water is better. Saving hot indoor water is better still.

Saving end-use energy can also save water and the energy associated with the applicable portion of the water use cycle. For example, when air conditioning is reduced in large buildings that use cooling towers to remove the heat, every unit of energy that does not need to be removed means that less water is needed in the process. Also, saving electricity in any fashion saves water at power plants that use cooling water.

Agricultural Water Use Efficiency

About 79 percent of the state's water is used by the agricultural industry to grow more than 200 crops that generate more than $29 billion dollars a year for the state's economy (CDFA, 2003). Because water conveyance and pumping are very costly, efficient irrigation technologies and farming practices hold promise for reducing both the amount of water needed and the energy intensity of crop production.

While a unit of agricultural water is not as energy intensive as a unit of urban water, the agricultural industry strives to meet water conservation objectives, save money, and preserve water resources. Many times the adoption of natural resource conservation practices creates new energy expenditures. The industry can reduce these costs by participating in energy efficiency and demand response programs through the public goods charge funds administered by their investor-owned utilities (IOU).

Energy Efficiency and Conservation Measures

Since the mid-1990s, the agricultural industry has adopted multiple water conservation practices, among which are installation of drip- and micro-irrigation technologies. The use of on-farm pressurized irrigation methods has increased from about 1.4 million acres in the early 1980s to more than 4.2 million acres today.[30] These changes can result in better crops, reduced water use, and the reduced use of fertilizers and chemicals, all of which result in greater productivity and energy efficiency.[31]

To be more productive, farms must also improve the efficiency of their water pumping systems. Since the 2000-2001 energy crisis, thousands of farmers and irrigation districts have used state- and ratepayer-funded pump test and repair program incentives. Many of the pumps were repaired to boost their pumping plant efficiencies.[32] When pump tests are performed and cost-effective pump repairs are completed, pump efficiencies can increase by 5 to 15 percentage points. This improved efficiency provides increased pumping capacity. Where previously a farmer might have used seven days to water his fields, it might now instead take five or six days to do the same work. Most farmers will adjust their irrigation set times to reflect the new water output and reduce the total number of hours of operation, saving both water and energy.

These measures can more than offset the new energy requirements that most often accompany drip system installations. Although there will be a higher demand for connected load from the installation of booster pumps, the total hours of operation will depend on the source of water and the irrigation system that is being converted to drip. Most often farms are required to pump from groundwater sources to satisfy the on-demand, clean, and flexible water delivery needs of the drip systems, possibly increasing their energy costs. Studies have shown that the conversion from surface irrigation to drip/micro- and sprinkler-irrigation technologies has lead to increased on-farm groundwater pumping on the east side of the San Joaquin Valley.[33]

Adoption of Time of Use (TOU) Agricultural Electric Rates

Large numbers of both Pacific Gas and Electric (PG&E) and SCE agricultural customers have signed on to TOU electric rate schedules. In the PG&E service area 81 percent of agricultural revenues and 89 percent of agricultural kWh sales are on TOU rates, representing 40,000 accounts of the total 80,000 agricultural accounts[34]. In the SCE service area, 71 percent of agricultural kWh sales are on TOU rates, generated by 18 percent of the utility's customer accounts[35].

[30] CalPoly ITRC, Memorandum, 2005
[31] CalPoly San Luis Obispo University, ITRC Report No. R 96-001, Row Crop Drip Irrigation on Peppers Study - High Rise Farms, 2006
[32] Nexant, M&V report from the California Energy Commission Agricultural Peak Load Reduction Program, 2003
[33] CalPoly ITRC, California Agricultural Water Electrical Energy Requirements, 2003
[34] Personal communication with Keith Coyne, PGE, 8 4 2005
[35] Personal communication with Cyrus Sorooshian, SCE, 8 11 2005

Although there are many accounts on TOU rates, farmers still use energy during peak-period hours. If crop water needs require irrigating during peak periods, the farmer will exercise the option to use on-peak power and pay the penalties, leading to higher average energy costs. The farmer's goal is to provide water to crops when it's needed, in the proper amount, using high distribution uniformity for optimal crop growth. It is not always possible to meet all of these requirements and take maximum advantage of TOU rates.

Staff recognizes that, to pump water during off-peak hours, farms will require larger pumping plants with properly designed irrigation systems, improved control systems, and flexible working hours. To take full advantage of these changes farmers will have to maintain high efficiencies in their pumping and irrigation systems in addition to adopting scientific irrigation scheduling management practices.

Agricultural electricity end users would benefit from energy policies that allow end users to choose the demand response practice that best meets the requirements of their business. The industry will also be more inclined to invest in peak load reduction measures with both flexibility and strong stable price signals.

Other Factors Affecting Agricultural Water Energy Use in California

There are several trends to watch that affect the future use of energy to provide water to agriculture, including:

- Sustained adoption of drip and micro irrigation technologies. Although there are more than 4 million acres under drip irrigation, from a total of less than 9 million acres of irrigated land reported for the state, it is reasonable to assume that, over time, another 3 million acres could be converted to drip irrigation. The agriculture industry will make the conversion partly to meet water conservation goals but mostly by recognizing the production benefits from the technology. CalPoly ITRC forecasted an increase of 2.9 million kWh from the doubling of drip irrigation acreage.[36]

- Continued reliance on ground water, with reductions in surface water. There is a high probability that farmers will continue to pump from wells to supply groundwater to drip systems until irrigation districts provide surface supplies with flexible schedules.

- An increase in agricultural water conjunctive use programs with transfers to urban regions. There are many water transfer agreements already in place, with more to come as the urban sector finds that the agricultural industry can provide storage services as well as new water transfers from achieved

[36] CalPoly ITRC, California Agricultural Water Electrical Energy Requirements, 2003.

conservation measures. There are significant energy expenditures to accomplish the process of banking the water, pumping it for extraction and delivering it to the water account owner[37].

- Conversion from diesel-powered pumping systems to electric motors. On August 1, 2005, a new rate schedule (AG-ICE) became available for current agricultural diesel-driven irrigation pumps in both PG&E's and SCE's service territories. The rate encourages the switch from engines to electric motor-driven systems for agricultural customers with diesel engines of greater than 50 horsepower for irrigation pumping before September 1, 2004. In the PG&E territory it is possible that 200 to 300 MW of new coincident peak load could be added to its system during the course of the two-year open enrollment period.[38]

The Energy Commission's *2005 California Energy Demand Forecast* shows that agricultural electricity consumption is expected to increase by 1.4 percent a year through 2016.[39] The actual amount will fluctuate depending upon the total number of irrigated acres, the crop patterns, the source of water and, obviously, the price of electricity.

From a state energy policy perspective, the agricultural industry's effort to achieve electricity use efficiency and demand response savings would satisfy the first target in the state's loading order. The agricultural industry also has the opportunity to adopt the second item in the loading order with installation of renewable energy systems.

The agriculture industry does have great potential to develop renewable energy sources. However, investment recovery will require the aggregation of electricity account meters so that the generated power can be applied to all existing accounts. Today, these accounts can only apply the power produced to the single connection attached to the power system. Therefore only a limited amount of power can be sold at the retail price, with the remainder sold at wholesale prices. This situation is similar to that faced by water and wastewater utilities. These issues affect many customers in the state and are being considered by the CPUC as it attempts to balance a wide variety of factors related to distributed generation in California.

The agricultural industry's economic sustainability greatly depends upon nature's water cycle. During dry years, the amount of energy used to deliver water increases. In drought years, groundwater sources are used extensively to supplement lower surface water deliveries. Several consecutive dry years can also lower the groundwater subsurface level of the water table, requiring more energy to overcome the lift needed to pump the water up to the surface. Typical groundwater lifts vary by

---

[37] CalPoly ITRC, California Agricultural Water Electrical Energy Requirements, 2003) [http://itrc.org/reports/energyreq/energyreq.pdf].
[38] Personal communication with Keith Coyne, PG&E August 4, 2005.
[39] *California Energy Demand 2006-2016, June 2005*

region throughout the state, which influence both motor size and power usage. The state has been fortunate in that there has not been a continuous series of dry years since the 1988-1992 drought. Since then, new groundwater recharge basins have been developed to serve as infrastructure for water transfer transactions. These measures are important both for water management flexibility and energy efficiency.

Additional small-scale water storage systems located in irrigation districts and on farms could help increase the flexibility of water deliveries. Surface and tank storage facilities can store water during off-peak periods and reduce the need for on-peak electricity consumption.

Urban Water Use Efficiency

Approximately 21 percent of the state's water is for urban uses. Urban water use efficiency includes improvements in the residential, commercial and industrial sectors. It includes opportunities to increase the efficiency of water-related end uses that use either electricity or natural gas.

In November 2003, the Pacific Institute published a study[40] that estimated the minimum cost effective urban water conservation at around 2 million acre-feet (651 billion gallons) per year, about 22 percent of all urban water use -- without technological change. The California Urban Water Conservation Council (CUWCC) recently posted the results from 32 percent of the agencies that signed on to their memorandum of understanding to institute best management practices (BMPs) in their water agencies. Taking only those BMPs for which water savings could be quantified, the reporting agencies saved more than 27 billion gallons of water in 2004, resulting in significant electricity energy savings, as shown in Table 4-1. The water savings from the BMPs, reported in 2004, are roughly 4 percent of the potential described by the Pacific Institute.

[40] *Waste Not, Want Not: The Potential for Urban Water Conservation in California,* The Pacific Institute, November 2003.

Table 4-1: Energy Value of Saved Water Due to Implementation of 2004 BMP Measures

Statewide	Annual Savings Water (MG)	Annual Savings Electricity (kWh)	Useful Life (Years)	Life-Cycle Electricity Savings (kWh)	NPV Electric Avoided Cost ($)
BMP 1 Water Survey Programs MF/SF	1,897	17,114,500	5	85,572,500	6,220,866
BMP 2 Residential Plumbing Retrofit	311	2,814,000	5	14,070,000	1,022,865
BMP 4 Metering & Commodity Rates	1,587	14,317,200	11	157,489,200	9,472,790
BMP 5 Large Landscape Conservation Programs	5,320	34,595,450	10	345,954,500	21,149,701
BMP 6 High-Efficiency Washing Machine Rebate	317	2,860,100	15	42,901,500	2,346,888
BMP 9 Conservation Programs CII	4,814	43,433,300	12	521,199,600	30,567,522
BMP 9a CII ULFT	258	2,328,300	25	58,207,500	2,522,363
BMP 14 Residential ULFT	12,987	117,184,600	25	2,929,615,000	126,950,010
Statewide Total	27,492	234,647,450		4,155,009,800	200,253,005

Source: California Urban Water Conservation Council (CUWCC) Reporting Database, April 2005 with 86 of 269 Reporting Units (32%) reporting BMP expenditures in 2004. Reporting Units include: water utility districts, water agencies, irrigation districts, city and county water departments and water service companies implementing BMPs.

Saving this water also saved more than 234 million kWh of electricity. Taken over the lifetime of each measure, the net present value of the energy for this saved water is more than $200 million. The saved energy was computed using the urban use energy intensity of 4,000 kWh/MG in Northern California and 12,700 kWh/MG in Southern California. These values assume that all water delivered to these uses is also treated as wastewater and applies to all of the BMPs (except the landscape conservation programs, which used a lower number to account only for the water delivery portion of the water use cycle). The computations were done separately for Northern and Southern California and aggregated to arrive at the statewide totals shown in the table. Details of this analysis can be found in Appendix C.

The energy saved from the saved water was passed on to the California water and wastewater treatment utilities that participated in implementing the BMPs. It also showed up as reduced electricity sales and some peak demand reduction. However, energy savings from savings in the water use cycle were not recognized by either the CPUC or by the energy utilities as fundable energy conservation measures.

Members of the Water-Energy Relationship Working Group presented testimony on this topic, suggesting it would be valuable to assess how large the energy value of the conservation potential identified by the Pacific Institute might be in comparison with energy efficiency programs currently approved by the CPUC. Table 4-2 presents the comparison of programs funded in 2004-2005 with those planned for 2006-2008. The water use efficiency (WUE) program is based on the Pacific Institute's expressed water saving potential.

Table 4-2: Comparison of Energy Efficiency Programs Resource Value to Water Use Efficiency

	Energy Efficiency Programs		
	2004-2005	2006-2008	WUE
GWh (Annualized)	2,745	6,812	6,500
MW	690	1,417	850
Funding ($ million)	$762	$1,500	$826
$/Annual kWh	$0.28	$0.22	$0.13
WUE Relative Cost	46%	58%	

Source: California Public Utilities Commission, with WUE estimates from Appendix C

The numbers for the energy programs are from CPUC documents.[41] The numbers for the WUE program are discussed in detail in Appendix C. The energy savings were assigned to Northern and Southern California based upon their respective populations. The cost of water efficiency measures assumes an average of $384 per acre-foot, based on a range of $58-$710.

There is clearly significant untapped energy savings potential in programs focused on water use efficiency. If all of the identified urban water savings could be achieved, the energy savings would achieve 95 percent of the savings expected from the 2006-2008 energy efficiency programs, at 58 percent of the cost. Peak savings could account for 60 percent of the utilities' expected demand reductions.

TOU Water Tariffs and Meters

The idea of TOU water tariffs and meters was suggested several times during the proceedings as a means to give customers a more accurate assessment of the value of the water they use. Historically, water agencies have treated their product as a commodity; water flows and people use it. Before the 2000-2001 energy crisis, even though water agencies were on standard TOU and demand rates, the incremental costs between on and off peak were not large enough to affect their decision making. They did not attach time value to water until SWP and the state water contractors became sensitized to hourly energy costs in the highly volatile bulk power market. At the retail level, it is important to recognize that many water customers in the state do not even have water meters, although legislation is changing that. Currently, TOU water meters do not exist. Water agencies are also grappling with how to develop tariffs and rate schedules that both properly reflect the value of water at different times during the day and account for delays between

[41] 2004-2005, CPUC Rulemaking R.01-08-028, Decision D.03-12-060, 2005-2006, CPUC Rulemaking R.-01-08-0228, Decision D.04-09-060.

energy consumption and water use. The Energy Commission is funding a project to look at the feasibility of these meters and associated tariffs.

Because the vast majority of the financial benefits of water use efficiency go to customers instead of water, wastewater, or energy utilities, informing customers of the financial upside of more efficient appliances and practices could be very effective. The new "Flex Your Power at the Tap" campaign is one example. In the longer term, water and energy bills could also serve as informational pathways leading customers to efficiency investments and choices that are best for both them and the greater society.

Water Storage for Peak Electric Load Shifting

Water and wastewater treatment require approximately 3,000 MW of peak load. There is a minimum level of electrical consumption needed to operate their systems during peak periods. Beyond that, virtually all of the on peak energy use is discretionary - if there is sufficient storage. For example, the El Dorado Irrigation District reduced its on-peak electric usage by more than 60 percent by allowing their tanks to drop to a lower minimum level and installing an additional 5-million-gallon storage tank. An estimated 250 MW of peak demand could be saved if water agencies statewide viewed their storage as an energy asset as well as a water asset. Another 1,000 MW of peak demand could be saved from increased treated water storage in urban areas. In total this represents more than one-third of the water use cycle load.

Investing in Water and Energy Efficiency

California has water-related energy programs to increase the energy efficiency of existing water and wastewater utility operations; increase the energy efficiency of the appliances that move water; and increase generation from renewable resources. These programs include building and appliance standards, technical support and loan programs, and incentive programs funded through the state’s energy utilities. The state also conducts research to modify existing treatment processes; develop more efficient water and wastewater treatment and water supply technologies; increase the efficiency of heating, cooling, and moving water for end users; and improve the effectiveness of renewable energy sources.

However, since the state’s largest energy utilities have no authority to invest in programs that save cold water to capture the upstream energy benefits, these benefits are not realized. If the CPUC authorizes investment in cold water savings, the state will have a new source of energy savings.

Because of the interconnectedness of water and energy resources in California, the fact that cost-effectiveness is determined solely from a single utility and single resource perspective is a glaring problem. Water utilities value only the cost of treating and delivering water. Wastewater utilities value only the cost of collection, treatment and disposal. Electric utilities value only saved electricity. Natural gas utilities value only saved natural gas. This causes underinvestment in programs that would increase the energy efficiency of the water use cycle and increase agricultural and urban water use efficiency.

By valuing a unit of water on its total value – the water resource itself, plus its energy intensity and externalities throughout the entire water cycle -- many water and energy programs and measures that could not meet the earlier cost-effectiveness threshold are now possible. California could reap large energy benefits by encouraging greater collaboration between energy, water, and wastewater utilities.

Conclusions

In this chapter, staff has generally described the water energy intensity for agricultural and urban end uses. Staff recommends additional research to provide needed information to better understand these systems and how modifications or improvements could benefit the energy sector. Future regulatory change will also affect the overall energy demand of these systems. To ensure high-quality water supplies for the state, energy and water utilities should collaborate to efficiently operate water and wastewater treatment facilities. Water and wastewater utilities can take advantage of current energy efficiency programs for near-term retrofits and design modifications to increase efficiency now, with existing technology. Additional research is needed on technologies and system designs.

CHAPTER 5 – RENEWABLE ENERGY GENERATION POTENTIAL

The most widely recognized aspect of the water-energy relationship is power production in large scale hydroelectric dams. However, water and wastewater utilities have other opportunities to develop energy supplies. These include biogas cogeneration at wastewater treatment plants and development of local renewable resources on water and wastewater utilities' extensive watersheds and rights-of-way. For purposes of this paper, we will address the potential for new renewable generation by water and wastewater utilities for two distinctly different types of opportunities:

- Distributed generation
- Utility scale generation

These energy generation opportunities require different types of permits, approvals, metering, and interconnections, and have different production characteristics, economics, and operating and financial risks. Detailed aspects of distributed generation and large-scale hydroelectric generation are addressed separately in the *Energy Report*. [42]

Table 5-1 illustrates the range of renewable power production opportunities for water and wastewater utilities.

Table 5-1: Renewable Power Production Opportunities

Energy Resource	Distributed Generation	Utility Scale Generation
Hydropower	Energy Recovery through In-Conduit Hydropower	▪ Relicensing ▪ Pumped Storage ▪ Repowering
Biogas	Biogas Co-Generation	Biosolids Waste-to-Energy plants that utilize methane from sewage digesters, dairy manure, agricultural and food processing wastes, and other organic materials
Solar	Photovoltaics for irrigation pumps & motors	Central concentrating solar power plants (solar thermal and photovoltaics)
Wind	Modest site specific applications	Wind farms on watershed lands
Advanced Generation, including Fuel Cells and MicroTurbines	Potential applications for small pumping loads	n/a

[42] For a complete listing of all documents and reports associated with the IEPR proceeding, including distributed generation, please see [http://www.energy.ca.gov/2005_energypolicy/documents/index.html].

The potential, issues, and challenges of these opportunities are discussed below.

Distributed Generation

The term distributed generation is used to describe both customer-side and utility-scale generation. For purposes of this staff report, distributed generation refers to generation facilities sited on the customer side of the meter that are used primarily to serve a customer's own energy requirements, specifically a water or wastewater utility. This discussion is limited to opportunities for water and wastewater utilities to self-generate power, and the barriers and hurdles that prevent them from generating more. These facilities include in-conduit hydropower, biogas combustion, and other small-scale distributed generation facilities.

In-Conduit Hydropower

Wherever there is flowing water, there is both energy and the potential to capture and utilize that energy. In-conduit hydropower captures the energy from flowing water in a pipeline with a turbine or generating device installed directly in the conduit. Most of the state's large water conveyance projects already take advantage of the energy in water flowing through their pipelines, canals, and aqueducts. Additional opportunities remain to develop new or retrofitted generation in the state's water systems, if costs and risk can be minimized. These are environmentally attractive because they are built in existing water and wastewater systems.

In most cases, in-conduit hydropower potential ranges from very small – 1 or 2 kW to a high of about 1 MW. Often, the hydropower site is not near loads, requiring construction of expensive transmission or distribution lines to interconnect to the electric system. Even in cases where it may be cost-effective to construct such lines, existing rules do not allow the produced power to be credited against the water or wastewater utility's total energy bills. Instead, wherever such self-produced power cannot be directly connected to an existing load, it must be sold into the wholesale bulk power market. The costs and complexities of participating in the wholesale bulk power and transmission markets are daunting, even for large generators. They are prohibitive for very small generators.

A recent Energy Commission Public Interest Energy Research (PIER) study estimated the statewide developable potential of hydropower capacity in manmade conduits (including pipelines, irrigation ditches, canals and aqueducts) at about 255 MW - 231 MW at coincident peak - with annual production of approximately 1,100 GWh. The potential was about evenly split between municipal and irrigation district systems.[43]

---

[43] *California Small Hydropower and Ocean Wave Energy Resources*, Mike Kane, Energy Commission PIER, April 2005.

The PIER study focused on identifying the statewide potential for RPS-eligible small hydropower (less than 30 MW). Under SB1078, RPS-eligible hydropower must be constructed on or after September 12, 2002, and must not require a new diversion or a new appropriation of a water right.[44] Consequently, staff determined that the most likely class of hydropower to be developed under the present RPS is small hydropower within conduits. The PIER study only considered sites with potential of at least 100 kW since projects of lesser size tend to be uneconomic.

Changes in technology may reduce the economic threshold of in-conduit hydropower to less than 100 kW. New packaged systems are being developed that could be dropped into pipelines and other types of conduits – like canals and aqueducts - without expensive civil works or permitting costs. However, the challenge of siting in-conduit hydropower close to local loads remains.

Another way to look at in-conduit hydropower is to view it as an increase in the energy efficiency of the water delivery system. Without water agency investment in the water delivery system in the first place, this resource would not be available. Currently in-conduit hydropower is treated like any conventional energy generation resource owned and operated by a non-utility generator. This classification seems inappropriate since there is no prime mover and no new natural resource is used to generate the electricity.

Existing energy efficiency programs can be tailored for special circumstances, using customized incentives and standard performance contracting. Water agencies have taken advantage of these incentives for energy efficiency improvements, including increasing pipe diameter to reduce friction losses and the requisite pumping requirements; installing a parallel pipe system; and changing pump impellers and lining pipes to reduce friction losses. In-conduit hydropower could be looked at in a similar fashion and be included as an element of these tailored programs. Again, the issues of interconnection and the sale or application of the power to multiple accounts will still need to be addressed.

Biogas

Another option for developing generation in the water sector is to increase beneficial use of digester gas produced by the sewage wastewater, dairy manure, and food processing wastes/wastewater. Biogas, primarily composed of methane, can be used for a combined heat and power production.

California has 311 sewage wastewater treatment facilities, 2300 dairy operations, and 3000 food processing establishments. Currently, about 50 percent of sewage sludge, 2 percent of dairy manure, and less then 1 percent of food processing wastes/wastewater generated in the state are utilized to produce biogas. Converting

[44] *Renewables Portfolio Standard Eligibility Guidebook*, Energy Commission Publication Number 500-04-002F1, adopted August 11, 2004.

these wastes into energy can help operating facilities offset the purchase of electricity and provide environmental benefits by reducing air and groundwater pollutants discharged.

Unused biogas is typically flared to the atmosphere. Not only is this a waste of a renewable resource – flared biogas creates odors and air emissions.

Biogas producing facilities can be near significant loads, for example the wastewater treatment plant itself. However, this load may be on multiple meters and current rules discourage full use of the available biogas for maximum generation for onsite or offsite loads. Currently, there are provisions under regulated tariffs that enable dairy operations to produce electricity from biogas resources at one location and use it to offset electricity use at multiple locations, under multiple accounts, for one customer. This same approach would significantly increase opportunities for biogas-fired (and other renewable) generation in water and wastewater agencies.

The Inland Empire Utilities Agency (IEUA) is a leader among regional wastewater treatment agencies for innovative and proactive energy management. IEUA's facilities process 65 million gallons of wastewater into high-quality recycled water. IEUA's wastewater treatment system has three anaerobic digesters. Dairy manure is collected from seven nearby dairies and processed through two of IEUA's digesters. At one facility, biosolids from the sewage treatment process are combined with dairy manure. At another facility, dairy manure alone is used to produce the methane that is piped to the Chino Basin desalter, where it is used to produce electricity for desalination of groundwater.

IEUA believes there is significant potential for increasing biogas production by combining different types of biosolids. For example, by blending dairy manure with food waste, IEUA expects this year to double its amount of biogas production (from 0.5 MW to the total load of the Chino desalter of 1 MW).

IEUA's biogas power production is expected to continue to grow as it adds another 15 MGD wastewater treatment plant next year, and it plans to develop another 10 MW in renewable biogas generating capacity with a centralized biodigester that will take dairy waste, green and food residuals (generally used to make compost) and biosolids to produce biogas for power generation and compost. IEUA is also considering using its excess biogas to heat water and sell a new product, hot process water, to industrial customers.

While IEUA has been much more successful than other wastewater utilities in the innovative development of biogas power production, it has not been simple.

Other Distributed Generation Options

Other distributed generation options include solar thermal, photovoltaics, small wind power, and advanced generation technologies including fuel cells and advanced microturbines. These distributed generation opportunities are discussed at length in the *Energy Report* proceeding.

Utility Scale Generation

Many water and wastewater utilities have the opportunity to develop utility-scale power production facilities that produce more power than utilities need for their own processes. With technical and funding support and removal of major barriers, water and wastewater utilities could become net exporters of power. Whether conventional hydropower facilities developed in conjunction with large water conveyance systems - like the Oroville Hydroelectric Facility, owned and operated by DWR on behalf of the State Water Project, or wind farms constructed on watershed lands – substantial untapped renewable resource potential resides with water and wastewater utilities that have little incentive, and, in fact, many barriers and disincentives, to develop these resources.

Large-Scale Hydropower

In addition to the in-conduit hydropower opportunities described above, utility scale generation consists of conventional hydropower (less than 30 MW) produced by water releases from natural or manmade impoundments like reservoirs and dams.

Opportunities for new hydropower dam and storage projects are extremely limited in California for a variety of reasons. Most economically viable sites have already been developed; but even where suitable sites exist, development is limited by lack of availability of unallocated water rights, environmental protection measures (such as Wild and Scenic Rivers, Endangered Species, and Wilderness Area designations), and strong opposition from environmental advocates.

Staff has investigated ways to balance the electric system benefits offered by hydropower with their significant adverse environmental impacts. Both the Energy Commission's *2003 IEPR*[45] and staff's *California Hydropower System: Energy and*

---

[45] *2003 Energy Report*. California Energy Commission, *2003 Integrated Energy Policy Report*, December 2003, Docket No. 02-IEP-1, Publication No. 100-03-019, page 43.

> "Hydroelectricity has historically played an important role in meeting California's electricity needs. Its low production costs and unique ability to meet critical peak demand have long benefited the state's ratepayers. Some hydroelectric projects unfortunately have serious environmental consequences, such as significant, ongoing impacts to many California rivers and streams, native salmon and trout populations, and the water quality needed to support sustainable riverine ecosystems.
>
> The restoration of imperiled salmon and trout fisheries is one of California's environmental policy objectives. ... [D]ecommissioning of high environmental impacts hydroelectric facilities that supply little power is a possible method of restoring important aquatic habitat."

Environment[46] provide key findings with respect to hydropower's value and impacts. Staff provides recommendations to minimize the adverse environmental impacts of these facilities.

At this time, only two utilities are expected to develop hydroelectric resources.[47] The Sacramento Municipal Utility District (SMUD) proposes the Iowa Hill Project to add 400 MW of pumped-storage capacity to its Upper South Fork American River Project. This may be especially helpful for integrating wind energy produced in the Delta, since the Delta breeze on a hot summer day usually begins a few hours after the daily load peak, which is driven by air conditioning. For San Diego Gas and Electric (SDG&E), about 40 MW of new hydro are planned, beginning in 2008, from San Diego County Water Authority projects.

Long lead times are needed to plan new hydro projects, prepare appropriate environmental documents, obtain a license from the Federal Energy Regulatory Commission (FERC), and build the project. However, opportunities for incremental development, such as adding or improving generation facilities attached to existing dams, water conveyance facilities, and powerhouses, remain an option for increasing California's hydropower production.[48] These opportunities include pumped storage and retrofit.

Pumped Storage

Pumped storage typically involves pumping water from a water source into a reservoir or tank, to be held for later scheduled hydropower production. Water is pumped uphill during off-peak hours and provides peaking capacity during on-peak hours. Pumped storage has high energy value since it is virtually the only viable means to store energy. There are several significant pumped storage projects currently under development:

- The proposed 500 MW Lake Elsinore Advanced Pumped Storage Project (LEAPS)[49].

[46] California Energy Commission, *California Hydropower System; Energy and Environment*, Appendix D to the *2003 Environmental Performance Report*, prepared in support of the *2003 Integrated Energy Policy Report*, October 2003, Publication No. 100-03-018. Prepared in support of the *Electricity and Natural Gas Report* under the Integrated Energy Policy Report proceeding (02-IEP-01), October 2003, Publication 100-03-018.
[47] *California and Western Electricity Supply Outlook Report* Draft, California Energy Commission, July 15, 2005, pages 74-76, posted on the website of the California Energy Commission.
[48] Excerpt from the *California and Western Electricity Supply Outlook Report* Draft pages 74-76, in progress for posting to the website of the California Energy Commission, July 15, 2005. For information about California's overall hydropower outlook, please refer to the Energy Commission's 2005 report, *Potential Changes in Hydropower Production from Global Climate Change in California and the Western United States*, prepared in support of the *2005 Integrated Energy Policy Report* proceeding (Docket # 04-IEPR-01G).
[49] EVMWD Web site (www.evmwd.com).

- SMUD's proposed 400 MW Iowa Hill Pumped Storage Development.

- The US Bureau of Reclamation is also exploring several pumped-storage options in the Upper San Joaquin River Basin.[50]

As with any dam or reservoir, development of new pumped-storage facilities faces major challenges. Some of the issues associated with conventional hydroelectric power generation and typical on-stream pumped hydroelectric storage facilities include:

- Water resources impacts - hydroelectric facilities may change stream flows, reservoir surface area, the amount of groundwater recharge, and water temperature, turbidity, and oxygen content.

- Biological impacts, including the possible displacement of terrestrial habitat with a new lake environment, alteration of fish migration patterns, and other impacts on aquatic life due to changes in water quality and quantity.

- Possible damage to, or inundation of, archaeological, cultural, or historic sites (primarily if a reservoir is created).

- Changes in visual quality.

- Possible loss of scenic or wilderness resources.

- Increase in potential for landslides and erosion.

- Recreational resource impacts/benefits.

Another possibility for developing new pumped-storage projects is to connect two or more existing reservoirs or lakes with new pipelines or penstocks for water pumping and power generation. A U.S. Department of Energy (DOE) study identified dozens of such potential reservoir pairs in California, requiring construction of an average of about 10 miles of pipeline to connect each pair. (Lamont 2004). Though this type of development would increase operating flexibility and peaking capacity without need to construct new reservoirs, it would still involve construction of large pipelines through difficult terrain on protected lands, which could require significant expense for environmental mitigations and permitting.

Because of the costs associated with new pumped-storage facilities using existing or new reservoirs, development of modular pumped storage (MPS) may have greater potential in the near future. MPS systems are not dependent upon

[50] USBOR website 2005a.

natural waterways and watersheds and can be sited in areas that avoid many of the issues described above. In fact, they are generally purposely sited away from sensitive areas to avoid the regulatory and operational complexity often associated with conventional pumped hydroelectric storage facilities. MPS systems can also be added to existing water systems wherever the necessary elevation difference exists. They could also be developed in places like abandoned mines, taking advantage of elevation differences and storage created by mine shafts and open pits. If their capacity was less than 30 MW, these pumped-storage facilities could also qualify for supplemental energy payments under the RPS.[51]

Retrofit[52]

Retrofitting existing hydroelectric facilities, specifically replacing turbine runners and generators with new, more efficient equipment, may increase the capacity of these facilities. To the extent that retrofit does not result in changed flows, no permits may be needed. Hetch Hetchy Water and Power increased the capacity of its system 48 MW by replacing turbine runners and generators with newer, more efficient equipment – at a capital cost of $8 million, less than 17 percent of the cost of installing a new unit of comparable capacity. Since the purpose of these retrofits was to increase the efficiency of hydropower production using the same amount of flows, no permits or approvals were required.

Existing hydropower facilities can be upgraded to increase both capacity and output without changing flows. Below are the primary means for attaining such efficiency gains:

- Tunnels. Most power tunnels in California were built using drill and shot methods for rock excavation. The resulting rough rock linings have high friction losses and capacity issues. Existing unlined tunnels could be lined to decrease friction losses and produce more power with the same amount of water. Existing lined tunnels can be made smoother by relining or coating abraded surfaces. Some tunnels can be enlarged or made smoother by selectively trimming tunnel walls. The longer the distance of the tunnel and the greater the friction, the greater the opportunity for incremental gains in power production. Some tunnel lining projects have increased hydropower production up to as much as 7 percent.

- Penstocks and Pipelines. Similarly, penstocks and pipelines could be relined or replaced to reduce friction losses during times of high flows. The decision to reline or replace is an economic one that depends in large part upon the remaining useful life of the hydropower facility itself. The potential benefit also

[51] Aspen 2004
[52] Matthew Gass, Engineering Manager, Hetch Hetchy Water and Power, San Francisco Public Utilities Commission.

depends upon the length of the penstock or pipeline, and the amount of friction losses. Here, again, benefits of up to 7 percent have been documented.

- Turbines. The easiest and frequently most economical improvement could be to replace a turbine's runner. Computerized design, manufacture, and improved testing and modeling methods have increased the efficiency of turbine runners. Minimum efficiency gains for replacements of turbine runners installed in the 1970s and 1980s have been reported at 1 percent. When older designs are replaced by customized efficiency designs, increased output as high as 30 percent has been reported.

Other types of hydropower efficiency gains are attainable through improved planning, controls, and management. Most large hydropower plants in California are multi-unit facilities. In many cases, there are opportunities to optimize operations by balancing the loads of individual units. Specialized computer selection software has helped attain performance improvements of 1-3 percent. In addition, improved controls and monitoring systems allow more efficient operations and reduce downtime from unplanned outages. All of these things have potential to increase net power production. Applied to the state's hydropower inventory, these minor tweaks could cost-effectively increase the state's total hydropower production by at least 3 percent within just a few years.[53] However, FERC rules regarding system modifications and upgrades will need to be reviewed to confirm the trigger points that could reopen a license to scrutiny.

There is constant tension among competing interests for water supply, water quality, hydropower production, and flood control. A better understanding of opportunities for optimizing the state's hydropower supplies and the key stakeholders needed to attain those incremental benefits would provide a useful framework for identifying feasible options and resolving points of conflict.

Other Renewable Resources

Both water and wastewater utilities have extensive watershed lands and rights-of-way with potential for wind and solar development.

- In spring 2005, the Semitropic Water Storage District completed installation of a 1 MW solar facility that provides peaking power for local pump loads.[54]

- At the Solar Power 2004 Conference and Exposition, San Francisco announced that it will soon build a 225 kW solar facility covering 20,000 square feet at its Southeast Water Pollution Control Plant.

[53] Matthew E. Gass, P.E., Engineering Manager Hetch-Hetchy Water and Power.
[54] Boschman 2005..

- IEUA will install solar panels on its new LEED Platinum headquarters, which was designed to reduce energy use by 90 percent and water use by 70 percent compared with its previous building. IEUA expects its headquarters to be completely energy independent by next year.[55]

- Hetch Hetchy conducted a wind resource assessment of its Calaveras watershed that indicated a potential of more than 30 MW.

The developable renewable energy potential owned by water and wastewater utilities is not yet known. It would be beneficial to identify, assess and prioritize these resources, and provide technical and financial assistance to help develop renewable energy for the benefit of all California ratepayers.

Barriers to Energy Production

Even when transmission is available to move the power out of a water agency's conduit hydropower, biogas, or solar facility, the water professionals interviewed for this paper expressed frustration with their limited ability to deliver self-generated power to their various facilities. Water and wastewater facilities are often dispersed over large distances. These facilities typically take electric service at multiple points and are metered separately at each point.

During public workshops and working group meetings, water and wastewater utilities cited the following primary barriers to self-generation:

- Complex, costly and long lead time interconnections.
- Prohibitive stand-by costs.
- Disincentives to fully utilize available renewable or distributed resources.

Issues of interconnections are being addressed by both the CPUC and the Energy Commission with respect to Rule 21.

Present regulations do not allow aggregation of a customer's electric metered loads within a single facility, much less with metered loads at their other facilities. Therefore, the only means for a water or wastewater utility to deliver self-generated power to itself anywhere on its system is to own and operate its own transmission and distribution systems -- essentially, to operate its own electric utility contiguous with its water service territory boundaries. Of course, this would be cost prohibitive.

At the April 8, 2005, *Energy Report* Committee workshop, IEUA identified the following barriers to its efforts to become energy self-sufficient and possible solutions to these barriers (Table 5-2).

---

[55] Davis 2005.

Table 5-2: Barriers to Energy Self Sufficiency

Barrier	Solution
Presently, IEUA is metered at multiple points, making it difficult to understand, plan and manage its total energy requirements.	The ability to aggregate all of IEUA's electric loads into a single consolidated load would enhance IEUA's ability to self supply its loads. In addition, it would enhance IEUA's ability to develop creative approaches, whether through modified system design and/or operations, to further reducing peak period consumption.
CPUC "single premise rules" discourage building generation greater than connected load.	IEUA would increase the size of its generation facilities if it had ability to wheel self generated power to itself.
Energy utility programs often fail to capture opportunities to encourage energy efficient design principles in water agencies' facilities.	IEUA and other water agencies have substantial continuous capital programs and, thus, opportunities to incorporate non-conventional energy efficient design principles into large facilities. For example, most of the cost of a new or replaced pipeline is in the trenching. The incremental cost of oversizing a pipeline is fairly modest and should be encouraged wherever cost-effective in reducing energy consumption. Some Energy Performance Contracting programs can be accessed for these types of projects; but applying for and collecting incentives are often difficult.
IEUA and other water agencies have unique opportunities for renewable energy development (e.g., biogas; pipeline conduit hydro; extensive rights of way and watershed lands); but the development costs and risks are often daunting for an entity for which energy is not its primary business.	IEUA is hosting various pilot programs that test and refine renewable energy technologies. Energy utilities could partner with water agencies to optimize development of their renewable energy potential, first to offset their own loads, and then potentially to also become net exporters of renewables and help energy utilities meet RPS and achieve other environmental benefits, including greenhouse gas reductions. Incentive programs are key to testing new technologies at scale. Net metering program (SB 728) will be essential to capturing value of renewable energy.

Source: IEUA testimony

Conclusions

Given the state's energy and capacity shortages, it would be beneficial to help water and wastewater utilities develop all potential renewable and distributed resources. This can be facilitated by allowing these utilities to aggregate their metered load and remove net metering caps. Excess power could then be sold to the energy utilities. Ultimately, the tension between energy utilities and their customers needs to be resolved through policy. The fundamental issue is whether customer-sited distributed generation provides an energy system benefit that reduces total societal costs.

CHAPTER 6 – POTENTIAL EFFECTS OF FUTURE CHANGES

Several factors are causing changes to California's water supply portfolio; legislative, regulatory, market, and technological changes will affect both water-related energy consumption and energy production.

The following discussion addresses a variety of known and anticipated energy impacts, the primary drivers of these impacts, and the extent to which the magnitude and timing of these impacts can be predicted. The primary drivers to be discussed are:

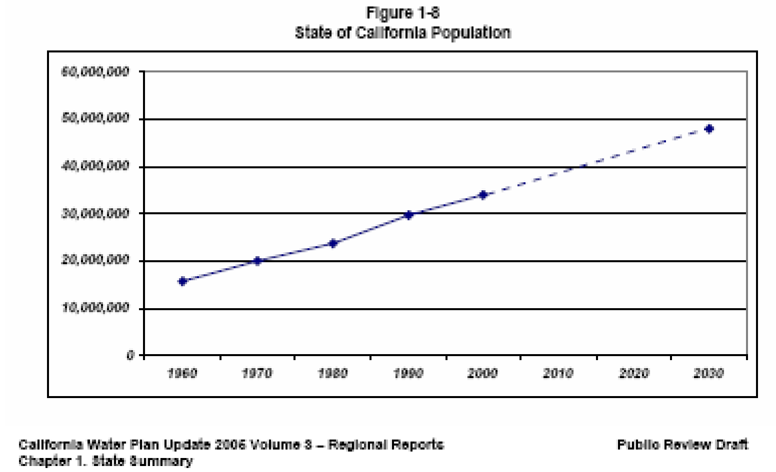
- Increased water demand
- Changes in water end use
- Changes in regulation and legislation
- Changes in water and energy markets
- Hydrology
- Technology
- Policy

Where reasonable bases exist for estimating these impacts, they will be described. If their impacts cannot be reasonably projected, staff identifies needed additional information.

Increased Water Demand

DWR, in the *2005 Water Plan Update,* based its estimates for water demand growth on data from the Department of Finance (DOF) that estimates California's population will increase more than 40 percent by 2030 - from about 34 million in 2000 to 48 million in 2030 (Figure 6-1). Absent mitigation, water-related energy consumption attributable to urban water use is expected to match this growth. The plan projects that, without mitigation, urban water use will increase substantially - as much as 6 million acre-feet, or 67 percent, by 2030.

Figure 6-1: Projected Population Growth in California



The actual impact of water demand growth on energy is difficult to predict for the following reasons:

1. The water supply portfolio planned to meet water demand growth is significantly different from the state's existing portfolio. Consequently, a simple extrapolation of the current average energy intensity of water supplies makes no sense.

2. The state water plan indicates that the largest new supply available to provide for the expected growth in water demand over the next 25 years is water use efficiency. To the extent that the state may not attain its targeted level of efficiency, any shortfalls in water supplies will need to be made up from other sources, most likely recycled water and desalination. Both of these options require new infrastructure that will need to be developed years before it is actually needed. If these are not in place in time, forced conservation, such as the shortage allocations during the 1987-1992 drought, may need to be implemented.

3. Industry experts predict there will be an increase in water market transactions. Some broad generalizations about water market transactions can be made. For example, to the extent that these transfers result in a net increase in physical deliveries of Northern California water supplies to Southern California or agricultural water use is converted to urban water use, energy consumption for water conveyance will increase. However, the net energy impact of increased water transactions cannot be determined. There are many variations in the types of transactions that could occur and no certainty as to which will or will not occur.

4. The recent Colorado River Quantification Settlement Agreement (QSA) requires that California beneficiaries of Colorado River water reduce their use over the next 14 years to California's basic annual allocation of 4.4 million acre-feet. A number of specific actions are being taken by Southern California water utilities to implement the QSA and make up for reductions in Colorado River imports.

> Strategies include increased water use efficiency, increased imports from the State Water Project, development of 126,000 acre-feet of desalinated ocean water, managing the San Bernardino Basin as a groundwater facility, increased use of recycled water, and paying farmers to fallow their land. It seems likely that these strategies will have significant impacts on energy use. However, the net impacts of all of the combined strategies and any offsets, such as reduced energy due to lower Colorado River imports, are not yet known.

In order to assess its range of potential impacts, staff estimated the energy implications of the water supply portfolio strategy illustrated by DWR for low and high growth scenarios. Table 6-1 shows that energy associated with the water plan strategy will increase water sector energy use by 12.3 percent in the low-growth scenario, to as much as 25.8 percent in the high-growth scenario, over the period 2000 to 2030. The energy impacts were derived by multiplying the energy intensity numbers for each type of incremental water source from Figure 2-2 in Chapter 2, by DWR’s projections.

Table 6-1: Estimated Energy Impacts of Proposed Incremental Water Supplies[56]

	Low Growth Projection				High Growth Projection			
	Water		Energy		Water		Energy	
Resource	MAF	%	GWh	%	MAF	%	GWh	%
Conjunctive Management	0.5	21.3%	475	19.2%	2.1	36%	1,995	40%
Recycled	0.9	38.3%	352	14.2%	1.4	24.1%	547	11%
Surface Storage	0.05	2.1%			1.0	17.2%		
Inland - Desalter	0.2	8.5%	340	13.7%	0.3	5.8%	570	11%
Ocean - Desalter	0.1	4.3%	440	17.8%	0.2	2.8%	726	15%
Conveyance	0.3	12.8%	870	35.1%	0.4	6.9%	1,160	23%
Precipitation Enhancemer	0.3	12.8%			0.4	6.9%		
	2.35	100.0%	2,477	100.0%	5.8	100.0%	4,998	100.0%
Current - Base	43		19,345		43		19,345	
Total Projected	45.35	5.5% Growth	21,822	12.8% Growth	49	13.5% Growth	24,343	25.8% Growth
Water Use Efficiency								
Urban	1.1				2.3			
Agriculture	0.2				0.9			
Total	1.3				3.2			

Source: 2005 State Water Plan Update, DWR for water projections. Appendix C for energy calculations

DWR's plan calls for urban and agricultural water use efficiency to make the largest contribution to the state's water supplies. However, conserved water will be redistributed to new users as the population increases. Recycled water, planned to provide almost 40 percent of incremental water supplies in the low-growth projection, will contribute 14 percent to incremental energy use. At the other extreme, ocean desalting is planned to provide only 4 percent of the incremental water, but will require almost 18 percent of the energy. These estimates are indicative of the need to better understand the energy implications when developing the state's future water supply portfolio.

[56] Low-growth projections reflect a 2030 water demand scenario where current trends continue, resulting in reduced agricultural irrigated crop area and reduced agricultural production. Urban water demand increases are linked to population increases and corollary increases in employment sectors. Under this scenario, per-household as well as per-employee water demand decreases slightly. Environmental water demand increases, and naturally occurring conservation decreases slightly. Population growth is based on Department of Finance (DOF) 2004 projections for growth and density.

High-growth projections reflect a 2030 water demand scenario where agricultural irrigated crop areas hold constant with year 2000; urban related water demand grows significantly, linked to population growth exceeding DOF projections by 12 percent, and lower overall population density and greater population growth occurs in inland and in southern hydrologic regions. Per-household and per-employee demand is elevated, and naturally occurring conservation decreases slightly. Urban water prices continue current trends.

Changes in Water End Use

A number of factors are driving changes in water end use. Changes impact both the urban and agricultural sectors. There are many types of changes – some that may increase energy consumption and some that may decrease energy consumption. Net impacts are difficult to predict. The discussion below about changes in agricultural water use illustrates the complexity of evaluating the net energy impacts of changed water use patterns.

Changes in Agricultural Water Use

As discussed in Chapter 4, changes in crops and irrigation methods affect overall energy demand. In the future, staff expects that periodic changes in crops will occur. Staff cannot predict what those changes will be. Consequently, only general statements can be made about the energy impacts of different trends. The *California Water Plan* projects that the agricultural sector will reduce overall water demand, predominantly through conservation. Any saved agricultural water will likely be applied to higher energy intensity urban uses.

Other signs point to decreased energy use in the agriculture sector, including efforts to conserve water and energy, following the example of urban agencies that universally follow a set of BMPs in managing their systems. For example, some irrigation districts have signed on to a program sponsored by DWR that requires implementation of Efficient Water Management Practices (EWMPs) that address energy management (Efficient Water Management Practices by Agricultural Water Suppliers in California, Memorandum of Understanding, January 1, 1999). That effort was prompted by the Agricultural Water Suppliers Efficient Water Management Practices Act of 1990. However, unlike urban water systems where water conservation also brings energy conservation, agricultural water conservation can often lead to increased energy demand. Reuse of tailwater, for example, requires installation of additional pumps, and drip and microspray irrigation need more electricity than other irrigation methods. Some of these uses, however, such as reuse of tailwater, could have the benefit of avoiding long-distance conveyance energy use.

Utilities and agencies are also addressing agricultural energy use through several energy efficiency programs. A good example is the Agricultural Pumping Efficiency Program (APEP), run by the Center for Irrigation Technology, which is part of the California Agricultural Technology Institute at the College of Agricultural Sciences and Technology, California State University, Fresno. The program receives funding from the Public Goods Charge on utility bills and provides free pump efficiency evaluations for farmers and irrigation districts served by the state's three large investor-owned utilities. Since 2002, the program has resulted in at least 15 GWh of savings from approximately 350 pump retrofit/repair projects.[57]

[57] Canessa 2005

Taken together, no definite conclusion can be drawn concerning the future trend of energy use in the agricultural sector. It is necessary to look at all applicable portions of the water use cycle when assessing the net energy impacts. More work is needed.

Changes in Regulation and Legislation

There are a number of regulatory and legislative actions that will impact both energy consumption and energy production by the water sector.

Water Quality Regulations

Energy use for water treatment will increase as more stringent water quality rules are implemented under the federal Safe Drinking Water Act. These new rules require multi-stage disinfection including treating potable water more than once, which ensures removal of harmful organisms that may grow during storage and transport, and improved disinfection technologies that reduce the risk of carcinogens and other potentially harmful disinfection by-products. These improved disinfection technologies – principally, ultraviolet treatment and ozonation[58] – are much more energy intensive than prior chemical methods.

Energy use for wastewater treatment is also expected to increase because of new requirements under the Clean Water Act for treating effluent before discharging it into natural waterways. However, by increasing the quality of wastewater effluent, more recyclable water can be added to the water supply portfolio. Therefore, any increased energy use for wastewater treatment may be accompanied by a decrease from increased use of low energy intensity recycled water that can be used to displace higher energy intensity water supplies.

The actual impact of these new regulations is not yet known, and water agencies are still making decisions as to which treatment processes and technologies to adopt. In addition, the net impacts need to be better understood. However, a 2002 EPRI study estimated that these new water quality rules could increase energy consumption by wastewater treatment facilities by 20 percent between 2000-2005 and another 20 percent between 2006 and 2050.[59]

FERC Relicensing

FERC licenses 119 hydropower projects in California representing 11,930 MW, or 85 percent of the state's hydroelectric capacity. Thirty-seven percent of the state's entire hydropower system, totaling 5,000 MW, will be relicensed by 2015.

[58] Ozonation requires about twice the amount of electricity used by chloramination to disinfect the same quantity of water. In addition, the requirement for multi-stage disinfection increases the number of processes and overall electricity use.

[59] *Water & Sustainability* (Volume 4): *U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century*, EPRI, March 2002.

Typically, the FERC relicensing process results in increased requirements for in-stream flows. This has the result of decreasing overall hydroelectric generation. The National Hydropower Association reported a decrease of about 8 percent on average for the nation as a whole. The California experience has been less – a loss of about 2 percent in in-state hydroelectric energy production to date. An odd twist is that hydroelectric capacity actually tends to increase during FERC relicensing, as old units are either repowered or replaced.

In its *2003 Integrated Energy Policy Report*, the Energy Commission reported findings from analyses of six projects being relicensed. The analyses included studies of changes in energy capacity and production from the perspective of statewide and regional electricity supply adequacy and the reliability and cost of replacement power that would result if the proposals were implemented. The study concluded that combined annual energy production losses from relicensing would represent approximately 1 percent of the state's total annual hydroelectric production. The study concludes that "Specific decommissioning proposals would need to be fully evaluated on a case-by-case basis to identify potential local area reliability effects."[60]

Both the Energy Commission's *2003 IEPR* and staff's *California Hydropower System*: *Energy and Environment* provide key findings, as of October 2003, with respect to the potential energy and environmental impacts of FERC hydroelectric relicensing.

[60] California Energy Commission, *2003 Environmental Performance Report*. Appendix D, *California Hydropower System: Energy and Environment*, Sacramento, CA. 100-03-018, March 2003, p. D-4.

2005 Energy Policy Act
The 2005 Energy Policy Act (EPAct) recently signed into law by President Bush contains significant provisions that could affect both water-related energy use and production.

Water-Energy Relationship

- Funding for research, development, demonstration, and commercial applications to address water-energy issues including energy-related issues in optimal management and efficient use of water, and water-related issues in optimal management and efficient use of energy [Section 979].

Hydropower Incentives

- Ten-year production incentive payments for hydroelectric power from generation additions to existing dams or conduits completed within the next 10 years, limited to $750,000/year per facility [Section 242].

- Incentive payments for up to 10 percent of capital improvement costs for hydroelectric facilities that increase efficiency by more than 3 percent, not to exceed $750,000 per facility [Section 243].

- Inclusion of qualifying hydropower production (due to efficiency gains or capacity expansions placed in service after the date of the Act and before 2008) for Section 45 tax credits [Section 1301].

Other Renewable Energy Technology Development & Incentives

- Funding of more than $2.2 billion for fiscal years 2007-2009 for research, development, demonstration, and commercial application on renewable energy issues, including efficiency, cost and diversity, addressing a variety of renewable energy technologies (solar, wind, geothermal, hydropower, and other technologies) [Section 931].

- Funding of more than $750 million for fiscal years 2007-2009 to support a program of research, development, demonstration, and commercial applications for distributed energy resources and systems reliability and efficiency [Section 921].

- Funding for a State Technologies Advancement Collaborative (STAC) to research, develop, demonstrate, and deploy technologies where there is a common federal and state renewable energy interest [Section 127].

- Extension of in-service date deadlines to October 1, 2016, for facilities to receive renewable production incentive payments for solar, wind, biomass, geothermal, plus the addition of landfill gas, livestock methane, and ocean-related energy resources [Section 202].

- Extension of in-service date deadlines for two years, to December 31, 2007, for renewable energy production tax credits under Section 45 of the Internal Revenue Code of 1986 for qualifying facilities: wind, closed and open-loop biomass, geothermal, small irrigation power, landfill gas, and trash combustion [Section 1301].

- An increase in the Business Solar Investment Tax Credit, from 10 percent to 30 percent [Section 1337].

- Amendment of the Public Utilities Regulatory Policy Act (PURPA) of 1978 to add the requirement that each electric utility shall make available to any electric consumer a net-metering service relative to an eligible on-site generating facility [Section 1251].

Where significant tax incentives exist, there is the opportunity to develop public-private partnerships that bring private investment to help develop renewable energy resources. The impacts of the 2005 EPAct on renewable energy development of water and wastewater utilities' resources and assets cannot be determined.

Changes in Water and Energy Markets

Changes in both water and energy markets have potential to impact energy consumption and production by the water sector. For both, the primary driver of change is economics.

Water Markets

California's water markets are changing. The ability to sell water under some circumstances without losing water rights will likely increase transactions. The provisions of the Colorado River Quantification Settlement Agreement are driving Southern California water utilities to make changes in their water supply portfolios. Further, changes in the mix of crops being planted in California and economic pressures to convert agricultural land to urban use will affect water-related energy consumption.

As discussed previously, because the wide variety of potential transactions, it is difficult to project the net impacts of water market transactions on future energy use. Not all water transactions result in more transported water. Transactions often involve exchanges of water rights among multiple interconnected parties that merely allow the downstream purchaser to take more water from existing sources for a price that compensates each party involved in the transaction. The transaction can sometimes result in a net energy benefit, especially when reducing SWP or other energy intensive imports.

Energy Markets

The 2005 Energy Policy Act will certainly have an impact on the pace and types of renewable energy development. In addition, other impacts - natural gas and diesel price volatility, the impact of competition for renewables to meet RPS goals, and the cost of bundled versus unbundled delivered energy to various load centers - will all affect how agriculture and water and wastewater utilities use energy.

One example is the agricultural pumping switch from diesel to electric. Thousands of diesel-powered pumps are now operating in the Central Valley. With diesel prices soaring and air quality rules tightening, farmers are being encouraged to consider switching back to electric motors. ITRC estimates that converting all of those diesel engine pumps back to electric would increase energy consumption by 1,131 GWh (ITRC 2003). On August 1, 2005, both PG&E and SCE's "AGICE" (Agricultural Internal Combustion Engine) incentive programs went into effect. They are available to owners of pumps of 50 horsepower and above, provide a 20 percent discount over other agriculture rates, increase at 1.5 percent per year until eliminated, and offer an environmental adder that will reduce the costs to the customer of extending distribution lines to the pump. PG&E's program is capped at $27.5 million per year in total incentives, including discounts and environmental adders.[61] SCE's program is capped at $9.2 million. In the PG&E territory, it is possible that 200-300 MW of new coincident peak will be added to its system during the course of the two-year open enrollment period.[62].

Hydrology

There are two primary types of hydrological conditions that could affect both energy consumption and energy production by water and wastewater utilities: drought and climate change.

Drought

Changes in hydrology significantly affect the availability of water supplies and water use from year to year. The worst case scenario, from both a water supply and energy perspective, is a multi-year drought. During past droughts, surface water deliveries dropped in some places to less than half of average year deliveries, forcing water users to rely much more on groundwater pumping and emergency conservation measures.

During prolonged droughts, certain types of electricity use increase. For example, when surface water supplies are low, more groundwater is pumped. During

[61] Mayers, 2005
[62] Keith Coyne, PG&E, August 4, 2005

sequential dry years, water must be pumped from even greater depths as aquifer levels fall. Periods of drought also significantly increase pumping from existing and future conjunctive use field, as agencies tap emergency water supplies. An extended multi-year drought could also spark the rapid development of additional desalination facilities.

Estimating the water-related energy impact of a multi-year drought, however, is more complicated than simply adding up projected increases of energy consumption. During droughts, water shortage policies and plans place limits on water use by various market sectors and customer groups to allocate limited supplies. In addition, SWP and other large water systems will not have as much water to pump. The combination of these impacts would need to be netted out against incremental energy consumption for water supplies - like groundwater pumping and desalination - to understand the true energy impacts.

In evaluating water-related energy consumption from prior years, staff has been unable to find data that definitively support the premise that water-related energy consumption increases during dry years. In general, staff can say that an increase in water-related consumption and a decrease in energy supply are likely during a dry year. However, water industry experts are divided as to whether there is a net positive or net negative impact in energy consumption during a prolonged multi-year drought where serious reductions in water storage could trigger mandatory water use reductions.

Climate Change

A change in the patterns of rain and snow could have significant effects on both electricity production and consumption. Climate change scenarios show that global warming trends may result in more rain, but less snow. As a result, even when total precipitation is near normal levels, spring runoff will likely occur earlier in the year, resulting in early "spills"[63].

The Energy Commission has already conducted substantial research into the effects of climate change and is taking a lead role for the state in developing strategies to reduce greenhouse gas emissions. These efforts, as well as other statewide studies, were summarized in two recent Energy Commission reports prepared in support of the *2005 Integrated Energy Policy Report*. The first report, *Climate Change Impacts and Adaptation in California,* summarizes available scientific literature and provides a brief overview of the research agenda. The second report, *Global Climate Change*, provides background and context to guide the formulation of policy options for reducing greenhouse gas emissions in California.

[63] Overfilling of reservoirs in spring months, with spills bypassing turbines and reducing energy production and sometimes, also reducing summer peaking capacity.

A third report, *Potential Changes in Hydropower Production from Global Climate Change in California and the Western United States,* evaluated the potential effects of climate change on hydropower operations and production. This study included the following findings and recommendations:

- Climate change studies to date have depended upon broad trend analyses and are not yet useful in predicting impacts at the local watershed level.
- California is experiencing a warming trend. This could precipitate earlier snowmelts, reduce summer hydropower production and capacity, and increase summer air-conditioning loads.
- Although more work is needed to predict local impacts, warmer temperatures could cause earlier snowmelts, reducing stored water supplies.

Reduction of stored water has several potentially adverse impacts:

- Less availability of surface water supplies (which could lead to increased use of more energy intensive supplies).
- Less hydropower peaking capacity.
- Lower head (reducing hydropower energy production as well).

Clearly, climate change impacts will need to be studied over many years before the true net impacts on both energy consumption and energy production can be accurately measured.

Technology

Changes in technology could change energy consumption and energy production, though the net impact of such changes is undeterminable. Below are some examples of potential changes in technologies that could affect water-related energy consumption or energy production:

- In addition to continually seeking more efficient water and energy systems and processes (e.g., desalination and disinfection technologies), research continues into streamlining system processes and plant designs.
- In addition, research continues into improving the efficiency of pumps, motors, and equipment to reduce energy consumption and increase operating flexibility to shift loads off-peak.
- Specific research into modifying the reverse osmosis process used in desalination to reduce energy requirements is occurring in multiple forums.

- New technologies are improving the design of turbine runners, making it possible to increase both capacity and output of existing hydropower systems through retrofits. In addition, research continues into developing packaged systems that can be dropped into existing pipelines without need for costly civil works and low head turbine technologies.

- Automated controls technologies also optimize water releases to better balance hydropower production with water supplies and electric loads, and allow more efficient pumping in water and wastewater treatment plants.

The American Water Works Association Research Foundation (Awwa-RF) and PIER are already collaborating on a portfolio of research and development projects related to the interdependencies of water and power.

Policies

Several policies have been adopted for both the water and energy sectors. Policies to reduce water and energy consumption will certainly impact both the water and energy sectors, but the net energy benefits may differ. Energy demand could go up as a result of water decisions. Ultimately, it matters tremendously what policy options are implemented and how well these policies are coordinated for mutual water and energy benefits. Thoughtful policies can mitigate the potential adverse impacts of water decisions on energy resources and infrastructure.

Conclusions

The common theme of all of these potential changes is that there are both threats and opportunities. In order to better understand these and develop plans and measures that leverage opportunities and mitigate threats, more information is needed by water and energy policymakers and implementing entities. Ultimately, the *net* energy impacts of various water policies and strategies need to be well understood in order to tailor effective mitigation measures.

CHAPTER 7 – STAFF RECOMMENDATIONS

Findings

During these proceedings, state and federal agencies, water and energy utilities, industry associations, research organizations, and a wide variety of other stakeholders came together to consider the state's water-energy relationship and what it means to the state's energy resources and infrastructure. While acknowledging there is much yet to be learned about the nature and extent of the state's water-energy relationships, some things are clear.

- The relationship between the water sector and the energy sector is complex and highly interdependent.

  - ✓ In-state hydroelectric power generation in 2004 accounted for approximately 11 percent of the state's in-state energy resources. When hydropower imports from the Pacific Northwest and the Desert Southwest are included, hydropower accounted for as much as 15 percent of the state's energy in 2004.

  - ✓ The water sector is the largest consumer of energy in California, estimated to account for 19 percent of total electricity and 32 percent of total natural gas consumed in the state.

- Saving a unit of water reduces the amount of energy used to collect, treat, deliver it, consume it, treat it, and dispose of it as wastewater. If used elsewhere, this saved water may displace the need to develop new, more costly water sources.

  - ✓ With few exceptions, the avoided energy value embedded in a unit of water throughout the applicable portion of the water use cycle is not accounted for by either water or energy utilities.

  - ✓ Presently, the magnitude of this total energy savings cannot be fully calculated, though sufficient information exists to compute a proxy to support near-term programs.

  - ✓ The state's current energy programs (codes and standards, incentives, and rebates) focus on energy saved at a single location from increasing water and process heating efficiency – not on energy that can be saved from reductions in water use. Not including cold water savings misses significant energy savings opportunities upstream in the water use cycle.

  - ✓ There are significant differences in the energy intensity of the water use cycle between Northern and Southern California because of differences in the energy intensity of water supply portfolios that are heavily dependent on imported resources.

  - ✓ Options for new water resources in the future are limited. The least energy intensive option for future supplies is water use efficiency. The most energy intensive option is ocean water desalination.

  - ✓ Water that is not consumed generally becomes available to offset highest marginal cost supplies.

- Modifications to the operations or design of the water system infrastructure present opportunities to reduce water system peak electric demand.

  - ✓ Some existing surface storage facilities can be modified to maximize generation opportunities and increase operational (peaking, load following) flexibility.

  - ✓ Many existing and most new water and wastewater treatment plants can be designed to detain water for treatment during off-peak hours.

  - ✓ Increased conjunctive use programs may allow for greater ability to shift energy demand seasonally.

- Currently, most water and energy systems are internally optimized on a single utility basis. Systems are rarely optimized in coordination with other systems (water, wastewater, electric and natural gas) or with their customers, missing opportunities to reduce total energy consumption, shift loads off-peak, or maximize energy generation.

- Opportunities within a utility system to develop additional generation resources (in-conduit hydroelectric generation, biogas combustion, and other renewable development) exist. However, significant barriers frustrate development of these resources.

- Energy demand in the water sector will likely increase over time due to a number of factors, including population and urban load growth, increased water and wastewater treatment because of more stringent water quality regulations to protect water quality, and market, economic, regulatory, and legislative changes.

- Several actions can be taken now to significantly reduce energy demand throughout the water use cycle and slow its future growth. This is particularly true in areas, like Southern California, which have tight energy supplies and constrained transmission systems.

The state's water and energy utilities separately seek to optimize their respective water and energy resources within their own portfolios. There are strong similarities between their IRP goals, methods and techniques. However, in developing its water resource strategy, DWR did not synchronize its water resource planning goals and objectives with those of the Energy Commission to assure, for example, that local energy supplies and infrastructure can support greater desalination production. Where seawater desalination plants may be planned at points downstream of electric transmission congestion zones, the energy solution may be to build new generation in combination with the desalination plant. Another solution may be joint water and energy investments in recycled water infrastructure processing that could displace the need to build desalination facilities in the first place. This is one example of the types of water and energy tradeoffs that should be examined.

The most significant finding of this paper is that the greatest potential for positively impacting the state's energy circumstance is beyond current water and energy best practices. The opportunity is fortuitous, and the need is great. To accomplish mutually beneficial results will require increased coordination between programs and agencies, as well as a more complete understanding of the needs of both systems and customers. At a minimum, the state's future water plans should be coordinated with the state's energy management plans to both identify and reconcile potential areas of conflict and take advantage of points of synergy. Optimizing the systems and operations of both water and energy utilities throughout the state on a holistic societal value basis will provide the greatest net benefits.

Staff Recommendations

Based on the findings in this analysis, staff recommends an action-oriented approach that is structured to attain near- and long-term results. This approach should include policy integration that seeks to optimize the mutual and synergistic benefits of the water and energy systems and resources. A key aspect of this approach is the development and implementation of a comprehensive, statewide water-energy program that integrates water and energy resource planning and management. The following essential elements have been identified for a successful program.

1. Save energy by saving water.
2. Reduce water system net power requirements.

Importantly, while this is a significant undertaking, near-term benefits could be attained while longer-term plans and studies begin at the same time.

Save energy by saving water

Even though water efficiency programs and conservation efforts exist in the state, there are many missed opportunities to save energy and manage load. These include energy savings throughout the water use cycle through water use efficiency; changes in systems and operations to reduce peak time-of-use and seasonal demands; and changes in water management to reduce use of the highest energy intensive supplies. This is particularly unfortunate in areas where energy resources are tight or peak energy demand is a problem. In fact, since load growth is the primary stressor of both water and energy resources, those areas that are shortest in water supplies are also energy constrained, making it even more crucial that the state's water and energy resources be managed on an integrated basis.

Staff concludes that the state could achieve nearly all of its energy and demand reduction goals for the 2006-2008 program period by simply allowing energy utilities to realize the value of energy saved for each unit of water saved. In that manner, energy utilities can co-invest in water use reduction programs, supplementing water utilities' efforts to meet as much load growth as possible through water efficiency. Remarkably, staff's initial assessment indicates that this benefit could be attained at less than half the cost to electric ratepayers for traditional energy efficiency measures. Staff should work with the CPUC and the energy and water utilities to evaluate the achievable savings and implementation strategies.

Staff therefore recommends that the state pursue policy options that achieve greater energy efficiency and saving through a more aggressive and comprehensive statewide water efficiency program. This program should target both site-specific efficiencies and actions that will result in net system energy savings. These actions could be a key part of the utility energy efficiency portfolios that accomplish savings needed to meet the CPUC's goals. Key elements of such a program include:

- Allowing energy utilities to count energy savings related not only to those achieved on site, but, where appropriate, those that can be identified throughout applicable portions of the water use cycle.

- Working with the Task Force, CPUC, DWR, and other stakeholders, refine data related to energy use and generation associated with the various parts of the water use cycle for use in accounting for the net energy impacts of this system and in calculating the effects of various programs designed to attain synergistic benefits.

- Target end user water efficiency measures that result in net energy savings – both on premises and in the water use cycle. For example, in addition to programs that save hot water, include programs that seek to maximize cold water savings in homes and businesses and count the net energy benefits attributable to a unit of avoided water consumption embedded in the entire water use cycle.

- Establish a collaborative with DWR, the CPUC, and the Energy Commission to achieve the state's least energy resource intensive water future by 2030. Align programs and policies to complement one another and remove barriers to mutually beneficial results.

- Invest in research that develops more water and energy efficient appliances, processes, designs, demand side management methods and technologies, and treatment systems.

- Establish a water resource loading order that incorporates the societal value of an avoided unit of water consumption that mirrors the preferred energy resource loading order in the *2005 Energy Report* and the Joint Agency *Energy Action Plan*.

- Establish a public goods charge equivalent for public purpose water conservation and efficiency programs that attain targeted net energy benefits.

- Require the state's energy and water planners to collaborate on plans and strategies to reduce net water sector energy consumption while meeting projected water and energy load growth with environmentally preferred resources and strategies.

- Commit public goods charge funds for expanded water efficiency programs and innovative technology development to reduce the net energy demand of the water use cycle in current 2006-2008 IOU energy efficiency portfolios.

Reduce water system net power requirements

The state should adopt a comprehensive policy to facilitate water and wastewater utility energy self-sufficiency by reducing water system net power requirements. This policy should include reducing operational energy requirements, shifting loads off-peak, and increasing energy generation from water- and wastewater-related resources and renewable opportunities. Implementing this policy is consistent with the objectives of the *2005 Energy Report* and the *Energy Action Plan* loading order and helps achieve the state's RPS goals.

- Develop cost-effective, environmentally preferred in-conduit, biogas and other renewable options for water and wastewater systems. To accomplish this, the Energy Commission should facilitate greater participation of water utilities in its loan and rebate programs by targeting planned retrofits at existing facilities and providing design assistance for planned facilities.

- Remove barriers to energy self-sufficiency by allowing water and wastewater utilities to self-generate power and provide this power to themselves anywhere on their systems; expedite and reduce costs of interconnections; eliminate economic penalties such as prohibitive standby charges; and remove caps on size of facilities eligible for net metering.

- Identify and implement retrofits in the water system that attain energy benefits, including but not limited to treatment system upgrades, turbine and pump replacements, and delivery system modifications.

- Require water and wastewater utilities to assess the energy impacts attributable to new or changed infrastructure and operations and evaluate feasible alternatives to reduce overall energy demand associated with these decisions.

- Provide incentives for incremental and/or joint infrastructure improvements that reduce total and peak energy requirements for water and wastewater conveyance and treatment.

- Facilitate collaboration among water and energy utilities and other local and state entities for the joint development of resources and infrastructure to further leverage benefits of their combined assets.

- Provide incentives for water, wastewater and energy utilities to optimize their joint resources beyond traditional discrete single utility service boundaries - water, wastewater, electricity, and natural gas.

In developing this report, Energy Commission staff established the Water Energy Relationship Working Group, which helped identify issues, evaluate possible resolution of those issues, and provide input on future policy options. This group demonstrated the need for the committed involvement of key stakeholders and an ongoing dialogue about the water-energy relationship. This cooperation and communication are vital to achieving the mutually synergistic benefits of water and energy systems.

Recommended Joint Actions

The Energy Commission, the DWR, the CPUC, the Air Resources Board, the State Water Resources Control Board, and the California Department of Health Services, should:

- Establish a valuation methodology for the water use cycle that accounts for embedded energy and externalities. This methodology is needed to capture these diversities in a manner that would assist planners in prioritizing their investments.

    - ✓ Incorporate a societal valuation approach in both water and energy utilities' resource pricing methodologies, water and energy efficiency program portfolios, and investment criteria.

    - ✓ To facilitate early results, establish a proxy for the societal value while a detailed methodology is being developed.

- Seek opportunities for joint investment that could produce incremental energy benefits but are not deemed cost-effective on a single-utility resource cost test.

- Leverage work already in progress by others, including the U.S. Department of Energy National Laboratories' Water-Energy Nexus Program, Pacific Institute, California Urban Water Conservation Council, and the Irrigation Training and Research Center. Work closely with these (and other) entities to:
  - ✓ Inventory, characterize, and measure California's water and energy interdependencies.
  - ✓ Develop pilot programs to test tools and methodologies for evaluating tradeoffs among these interdependencies.
  - ✓ Develop analytical models and tools for policymakers, regulators, utilities and other key stakeholders to use in developing cost-effective joint water and energy programs.
  - ✓ Research opportunities and technologies that improve the energy performance of the water use cycle and increase the generation capabilities of the water system.

Conclusion

While all of the nuances are not yet understood, it is clear that significant energy benefits are attainable through water use-efficiency and through increased energy efficiency in the water use-cycle. It is also clear that not nearly enough has been done to make sure that California's water supply strategies are synchronized with its energy strategies. Nor has enough been done to forge partnerships between the water and energy sectors and leverage the natural synergies of their joint resources and assets for the benefit of all Californians.

The state has the timely opportunity to reap near-term energy savings benefits by helping California's agricultural industry and water and wastewater utilities become more energy efficient. The CPUC could direct IOUs to invest current PGC funds for 2006-2008 energy efficiency programs in existing water infrastructure to improve operations, switch operations off-peak, and partially fund retrofits of equipment such as pumps and treatment equipment. These funds could also be used in conjunction with water conservation dollars to leverage greater water end use efficiency to realize net energy savings in the water use cycle. In addition, near-term actions could include minor adjustments to existing policies, programs, and market rules, to facilitate renewable and distributed generation development at water and wastewater facilities as well as agricultural resources to convert them from high energy users to net renewable energy producers.

For the long-term, California's water and energy policymakers need to commit today to joint planning and management of these critical resources. Conflicting policies and objectives need to be identified and conflicts resolved. Water resource plans need to include an accounting of energy impacts and evaluate alternatives to decrease overall energy demand of water systems. The state's energy resource portfolio needs to consider and facilitate the development of all cost-effective and environmentally preferred water system related options. Water and energy agencies and utilities need to work together to identify mutually beneficial research and develop opportunities that the state can pursue to improve both systems, followed with market transformation strategies to accelerate adoption of resource efficient behavior. To achieve mutually synergistic benefits in the water and energy sector, policymakers, agencies, and utilities will need to work together and make long-term commitments of funds and programs.

APPENDICES

APPENDIX A: EXISTING ORGANIZATIONS, PROGRAMS, AND RESEARCH

The California Water Plan

The Department of Water Resources (DWR) is responsible for updating the *California Water Plan (Plan)*, which provides a framework for water managers, legislators, and the public to consider options and make decisions regarding California's water future. The *Plan*, which is updated every five years, presents basic data and information on California's water resources, including water supply evaluations and assessments of agricultural, urban, and environmental water uses to quantify the gap between water supplies and uses. The *Plan* also identifies and evaluates existing and proposed statewide demand management and water supply augmentation programs and projects to address the state's water needs. Often referred to as Bulletin 160, the most recent version is scheduled to be published in late 2005.

DWR is also responsible for managing the State Water Project, including the California Aqueduct, and managing the contracts for electricity created following the 2000-2001 energy crisis. The department also provides dam safety and flood control services, assists local water districts in water management, conservation, recycling and desalination activities, and promotes recreational opportunities.

Energy Use in the Water Cycle

Energy is used in every phase of water use within the state, from extraction through conveyance, treatment, use, and disposal. The Energy Commission has funded several projects to define this interaction between water and energy.

Electricity and Water Flows with California
The purpose of this project, conducted by the University of California, Santa Barbara and the Pacific Institute, is to identify the flows of both water and energy within California. This includes water for electricity generation (hydropower) and all of the electricity used for water – from initial diversion or extraction through conveyance, treatment, use, and disposal. This project will increase understanding of the electricity demand for different water uses within the residential, commercial, and industrial sectors. It will also further understanding of the energy intensity of the water cycle. The results of this study will help focus future water conservation programs where they will make the greatest impact on energy (PIER Environmental[64]).

[64] The names in parentheses at the end of the paragraphs identify the group within the Energy Commission that is responsible for the activity described in the paragraph.

Groundwater and Surface Water Management and Electricity Demand
Conjunctive use of surface and groundwater supplies is increasingly relied upon as a water management tool. Concern about a significant increase in conjunctive use and its associated electricity demand, particularly under drought conditions, is a major concern. Conducted by Lawrence Berkeley National Laboratory (LBNL), the aim of this project is to see how surface and groundwater supplies will be managed under different climatic conditions, and what the consequences would be for electricity demand and prices. It is important to consider not only the likely impact of new conjunctive use programs on regional electricity demands, but also how reservoir management will affect water supply for agriculture and municipal uses and electricity generation and demand. (PIER Environmental).

The U.S. Department of Energy's Energy-Water Nexus Team

In partial response to an identified gap in federal jurisdiction at the nexus of energy and water, the Energy Policy Act of 2003[65] directed the U.S. DOE to:

- Assess future water needs for energy, future energy for water purification and treatment, use of impaired water by energy, and technology for water use efficiency.

- Develop a program plan that incorporates scientific and technology requirements, decision tools, demonstration projects, and information transfer.

Eleven national laboratories and EPRI came together to form the federal Energy-Water Nexus Team (Team), which is charged with developing technology products that will help increase the nation's energy security. The scope of the Team's investigations is very broad:

- Energy versus water tradeoffs in optimizing hydropower and the implications of those tradeoffs on energy supply risk.

- Energy usage by water-related systems and processes (including municipal water, wastewater, and industry).

- Water used to produce energy, such as hydropower and water for cooling.

[65] Section 961, Subtitle (f) *Water and Energy Sustainability Program*.

- Development of tools, including benchmarking, and opportunities to improve efficiency both through more efficient energy consumption and redesigning processes, systems, and operations.

- Financial and economic analyses of markets and participants, including impacts on equipment manufacturers and utilities.

- Environmental impacts, including the economic impacts of hydrology and climate factors, relationships, impacts, and interdependencies.

Presently, the Team is undertaking a road-mapping process for the US DOE, viewed primarily from the perspective of water used for energy and energy used for water - particularly with respect to the research and development of new technologies to improve water and/or energy use and efficiency.

The Ernest Orlando Lawrence Berkeley National Laboratory and the Lawrence Livermore National Laboratory are participating in the Energy Commission's Water Energy Relationship Working Group and can help merge efforts undertaken by the state and the federal government.

The ***2005 Energy Policy Act*** (EPAct) expanded the scope of US DOE's studies on the water-energy nexus.

Water and Wastewater Facilities

Energy consumption is a significant cost component of providing water and wastewater services to the public. The Energy Commission is dedicated to providing resources to help water professionals reduce these costs through implementation of energy efficiency measures at their facilities.

AB 970 – Peak Load Reduction at Water and Wastewater Facilities
At the peak of the 2000-2001 energy crisis, AB 970 provided $4.5 million in grant funding to reduce 52.1 MW of peak electrical load at water and wastewater facilities in four categories: curtailment, efficiency, generation, and load shifting. The grants ranged from $9,000 to $486,000, with an average amount of roughly $110,000 per project, at a rate of $300 per peak kW reduction. This program has been completed (Energy Efficiency Division).

SB 5X – Water Agency Generation Retrofit Program
The program started in May 2001 and was completed in December 2003. Projects were funded in two categories - distributed generation and energy efficiency - with a total on-peak load reduction capacity of 17.7 MW. Of this capacity, distributed generation retrofits provided up to 9.2 MW of on-peak load reduction, while energy efficiency projects provided up to 8.5 MW of load reduction. Twenty-eight qualified applicants received $4.35 million from this

program. The program paid distributed generation participants an average of $259/kW for projects with a combined construction cost of $7,205,488. Energy efficiency participants received an average of $230/kW for their projects, which cost $6,598,108 to install. Overall, the program averaged $245/kW of electrical load reduction (Energy Efficiency Division).

Flex-Your-Power's Water and Wastewater Guide: Reduce Energy Use in Water and Wastewater Facilities Through Conservation and Efficiency Measures

In response to the 2000-2001 energy crisis, the state's Flex-Your-Power program worked with hundreds of California water and wastewater agencies to develop measures to reduce energy consumption by 15 percent within their systems and facilities, for the purpose of both reducing power costs and alleviating the risk of rotating outages. A four-step process was developed to increase energy self-sufficiency through a combination of on-site power production, total energy consumption reductions through energy efficiency measures and retrofits, and peak shifting to partial- and off-peak periods wherever possible.

Energy Partnership Program

This program provides customized technical assistance to water and wastewater facilities to identify energy efficiency projects, project costs, and associated savings. Consultants are paid up to $20,000 for a detailed study of the facilities. Approximately $260,000 have been paid so far to consultants for feasibility studies, comprehensive energy audits, reviews of energy projects proposals, identifying cost-effective energy-saving measures, review of specifications for energy efficient equipment, and assistance in selecting contractors and design professionals for the water and wastewater facilities that have participated in this program (Energy Efficiency Division).

Energy Efficiency Financing Program

Energy Efficiency Financing Program: The Energy Commission provides low-interest rate loans to fund up to 100 percent of the cost of energy efficiency and self-generation projects. Loans are provided on a first-come, first-served basis. Eligible projects must have an average simple payback of less than 9.8 years. If projects have a greater simple payback, the Energy Commission can provide a loan equal to 9.8 times the annual energy cost savings. Eligible projects include pumps and motors, variable frequency drives, lighting, building insulation, HVAC modifications, automated energy management systems, automated energy management controls, energy generation, streetlights and light emitting diode (LED) signals. The Energy Commission has provided more than $11.2 million in loans for projects associated with both improving the energy efficiency of water and wastewater facilities and reducing the energy costs of these facilities. These projects have saved public facilities about $1.9 million annually in lower energy bills. This is equivalent to saving 23 million kWh annually, with billing demand savings of about 2.3 MW (Energy Efficiency Division).

Development of a Water and Wastewater Industry Energy Efficiency Roadmap

The Energy Commission collaborated with the American Water Works Association Research Foundation (AwwaRF) {Note: Thought I'd flag this since lower-case letters are so rare in acronyms – is this correct?] to develop a roadmap to fund the highest priority research and development energy needs of California's water and wastewater utilities. To achieve this, the Commission and AwwaRF in February 2003 conducted a workshop that was attended by water experts from water and wastewater facilities, electric utilities, academia, researchers, and consultants. More than 44 projects in eight research areas were developed and ranked according to their savings potential (in either kilowatts or dollars), likelihood of success, and timeliness. The Energy Commission and AwwaRF committed to more than $2 million in funding for the five highest-ranked projects. These projects are:

> **Development of a Utility Energy Index to Assist in Benchmarking of Energy Management for Water and Wastewater Utilities**
> The objective of this project is to produce industrywide energy performance metrics to describe the performance of water and wastewater utilities that will subsequently be incorporated within a comparison framework (benchmarking tool) to facilitate internal and external comparisons within and between utilities. The approach will be similar to the US EPA's **Energy Star®** program, which makes energy performance comparisons in commercial buildings (PIER Industry, Agriculture and Water).
>
> **Zero Liquid Discharge and Volume Minimization for Inland Desalination**
> This project is discussed in the section on desalination (PIER Industry, Agriculture and Water).
>
> **Assessing Risks and Benefits of Drinking Water Utility Energy Management Practices**
> The project will develop a decision framework based on risk management principles for water utilities implementing energy management strategies. The risks and benefits of a broad array of both supply-side and demand-side energy management options will be assessed. The decision framework will provide a management tool for water utilities to mitigate possible downsides to water quality and reliability when implementing energy management practices or technologies (PIER Industry, Agriculture and Water).

Water Consumption Forecasting to Improve Energy Efficiency of Pumping Operations

The purpose of this project is to provide the best options for short-term water consumption forecasting for water utilities. Short-term consumption forecasting (SCTF) is required for water utilities to proactively optimize both their pumping and treatment operations and water supply and treatment costs while maintaining a reliable and high-quality product for their customers. The project will provide information on various techniques, performance data, benchmarks, selection criteria, and functional requirements to help utilities evaluate and select the best forecasting techniques. The project will examine different forecasting methods currently used at public utilities. These forecasting methods will be tested at utilities that are not currently forecasting their water consumption, and the results will be documented. The SCTF performance data will be analyzed for all seasons of the year to provide peak, off-peak, and average-day consumption data (PIER Industry, Agriculture and Water).

Evaluation of the Dynamic Energy Consumption of Advanced Water and Wastewater Treatment Technologies

The objectives of this project are to quantify the actual and theoretical energy consumption of selected water and wastewater advanced treatment unit operations, evaluate the factors that affect energy consumption, and identify energy optimization opportunities while still maintaining treatment performance (PIER Industry, Agriculture and Water).

Future Projects in Collaboration with AwwaRF

Five more projects from the roadmap are being considered for future funding by the Energy Commission and AwwaRF.

1. Review of international desalination research. The product would be a searchable CD ROM database similar to Desal Net, owned by AWWA (<u>not</u> AwwaRF). Desal Net is a searchable CD ROM database for the U.S.
2. Energy consumption of ultraviolet and chlorine/hypochlorite disinfection.
3. UV disinfection: Develop next generation of energy efficient UV disinfection systems for water and wastewater treatment.
4. Development of a guidance manual to design and operate desalination facilities for maximum energy efficiency.
5. Identification and evaluation of innovative water treatment processes.

Agricultural Water

Energy consumption is a significant cost component of providing water to the agricultural industry. State and IOU ratepayer funds, administered by the Energy Commission, CalPoly San Luis Obispo, and Fresno State University have delivered energy efficiency and water conservation programs aimed at conservation and peak load reduction in agriculture. Programs include:

SB 5X –Agricultural Peak Load Reduction Program

- The program started on June 1, 2001, and was completed on December 31, 2004. The program components related to electricity used for water purposes, include:
- 1. The development and implementation of a pump test and repair program to improve pumping plant efficiencies.
- 2. Funding projects with irrigation districts and large farming companies to participate in demand response and TOU schedules. Over 60 MW of on-peak load reduction was achieved. Thousands of pump tests were performed and many of the tested pumps were repaired to achieve even higher efficiencies (Nexant, M&V report for California Energy Commission Agricultural Peak Load Reduction Program, 2003). More than $7 million were dedicated to water-related energy projects.

CPUC- Public Goods Charge (PGC)-Third-Party Administrator for Pump Test and Repair Program

The program, administered by the Fresno State University Center for Irrigation Technology, delivers pump test services to customers in the PG&E and SDG&E service territories. The pump tests are conducted by private sector providers that have enhanced the quality and standards of properly conducted pump test results for several years. The program also provides pump repair incentive payments. The educational component is a valuable tool for communicating efficiency principles and water conservation practices to farmers. A $5 million annual appropriation from the CPUC has funded this effort to date.

Development of an Agricultural Water Energy Efficiency Roadmap

The Energy Commission's PIER Agricultural Program Technology Roadmap was accomplished in collaboration with CalPoly San Luis Obispo, Fresno State University, the University of California Cooperative Extension Program, industry associations, farmers, and irrigation district managers. The roadmap document calls for research and development efforts that improve irrigation efficiency, create flexible water delivery systems, and achieve peak load reduction. Possible research, development, and demonstration projects include reducing the total pressure required to operate drip irrigation technologies (including the filter system as well as the pipe and micro-sprayer technologies), advancing the use of longer-lasting materials for pump components, and working with the State Water Project, the Central Valley Project, and the irrigation districts to increase the flexibility of water deliveries to farms. Additional information is available at: [http://energy.ca.gov/2005publications/CEC-400-2005-002/CEC-400-2005-002.PDF].

PIER Agriculture Energy End Use Efficiency

The purpose of this contract is to improve the energy efficiency in the transportation, delivery, and utilization of agricultural water provided by irrigation districts. Proposed outcomes include:

1. Documenting the implementation of new technologies.
2. Developing a simple procedure for tuning controller constants for automatic upstream control of canal check structures.
3. Developing new devices resistant to plugging or tangling moss for volumetric metering of delivered water - trash shedding propeller meters.
4. Testing and evaluating new electronic technologies for the volumetric metering of delivered water such as magnetic meters, ultrasonic meters (Doppler), vortex shedding meters, and ultrasonic flow-measurement meters.
5. Developing strategies for energy-efficient transition from low-pressure non-reinforced concrete pipe.
6. Verifying power quality measurement and conditioning methods.
7. Assessing use of variable frequency drives on agricultural pumps.

National Programs

Development of a National Water-Wastewater Industry Energy Roadmap
In order to bring together the energy efficiency and water/wastewater communities to define avenues for increasing energy efficiency in the water and wastewater sectors, the American Council for an Energy Efficient Economy (ACEEE) organized a national road mapping workshop to further explore and plan next steps for greater energy efficiency in the water/wastewater sectors. A workshop was held in Washington, D.C., in July 2004, and a final report is being refined for publication. The Energy Commission was a member of the advisory committee. The advisory committee defined the scope of this effort, developed a mission statement for the project, and established a set of goals. It also assisted ACEEE staff in identifying key issues relating to energy use in the water and wastewater industries. These issues formed the basis for design of a survey instrument that was used to collect impressions of key issues from a wider group of

stakeholders identified by the advisory committee. Based on this research and the goals of the workshop, ACEEE staff and the advisory committee developed an agenda that addressed key topics (Energy Efficiency Division).

National Municipal Water and Wastewater Facility Initiative
In 2002, the Consortium for Energy Efficiency (CEE) formed the Water and Wastewater Exploratory Committee to:

- Serve as a platform for members to exchange program information and resources.
- Better understand the water and wastewater industry - its structure, energy use, decision-making, and regulatory environment.
- Begin outreach efforts to the water and wastewater industry and other industry stakeholders.
- Explore the merits of a national program initiative to improve the effectiveness of local programs serving this sector. This initiative is intended to maintain a sustained focus on facility energy-efficiency at the national and local levels by increasing demand for energy-efficiency products and services within the municipal water and wastewater sector, and by transforming the delivery of products and services to the municipal water and wastewater sector by encouraging industry stakeholders to incorporate energy-efficiency as a standard business practice. The Energy Commission is a founding member of this initiative (Energy Efficiency Division).

US EPA's ENERGY STAR Water and Wastewater Facilities Initiative
ENERGY STAR is a voluntary program that helps organizations, businesses, and individuals protect the environment through superior energy performance. The ENERGY STAR Water and Wastewater Facilities Initiative helps improve energy performance by creating momentum for the continued improvement of energy efficiency by identifying and tackling barriers to energy efficiency in the water and wastewater industry, providing tools and resources to enhance energy performance, uncovering new energy-saving opportunities, and encouraging information-sharing on efficiency in the water and wastewater industry. The Energy Commission is one of the founding members of this initiative. The first Web conference on the Energy Star Water and Wastewater Facilities Initiative was on May 12, 2005 (Energy Efficiency Division).

Water Supply

Desalination

Desalination is one of the sources of new water identified by the Department of Water Resources in the ***2005 Water Plan Update***. It is also the most energy intensive of these new sources. There are several efforts underway to assist in the development of low-cost, energy-efficient desalination technologies for various source waters using membrane and thermal processes.

Improving Energy Usage, Water Supply Reliability and Water Quality Using Advanced Water Treatment Processes
The Energy Commission and the Metropolitan Water District of Southern California are jointly funding the full-scale demonstration and refinement of newly developed electro-technologies for producing potable and non-potable water. These technologies remove salts and disinfect various source waters, including Colorado River water, brackish groundwater, municipal wastewater, and agricultural drainage water. There are 18 individual projects and eight research partners involved in this research program (PIER Industry, Agriculture and Water).

Zero Liquid Discharge (ZLD) Desalination of Inland Waters
At coastal facilities, concentrate is typically discharged to the ocean. This option is not available at inland facilities, and the need to protect surface water and groundwater sources may preclude disposal into the environment. The alternative is ZLD, in which the concentrate is further treated to produce desalinated water and essentially dry salts. In collaboration with AwwaRF, this research project will develop technologies that reduce the cost and energy consumption for inland desalination (PIER Industry, Agriculture and Water).

West Basin Municipal Water District – Demonstration of a Low Energy Sea Water Reverse Osmosis (SWRO) Desalination
Energy is the single largest cost component of operating seawater desalination systems. The purpose of this project is to demonstrate that SWRO desalination can be performed at 1.6 kWh/m^3 of permeate produced. The project will also establish the relationships between reverse osmosis recovery rate, membrane salt rejection, permeate quality, boron levels, feed pressure, and energy consumption. These relationships will help the SWRO desalination industry establish optimum recovery, flux, and salt rejection rates using today's best-available technologies. This research is being conducted by the West Basin Municipal Water District, in collaboration with the DWR, several local water agencies, and the industry, in collaboration with the Naval Facilities Engineering Service Center's Seawater Desalination Test Facility at Port Hueneme, California (PIER Industry, Agriculture and Water).

California Desalination Task Force
In September 2002, AB 2717 (Hertzberg) was signed into law, directing the DWR to convene a Desalination Task Force (Task Force) to "make recommendations related to potential opportunities for the use of seawater and brackish water desalination." The work of the Task Force and its subsequent findings and recommendations provided a useful background to DWR in developing Proposition 50 guidelines for funding desalination

projects and for estimating the future potential and prospects of desalination in the ***2005 California Water Plan Update***. The Energy Commission served as one of the four co-chairs of the Task Force along with California Coastal Commission, State Water Resources Control Board, and State Department of Health Services (Energy Efficiency Division).

Salton Sea Desalination Demonstration Project Using Geothermal Heat
Energy Commission staff is serving on the advisory panel for U.S. Bureau of Reclamation's geothermal-driven vertical tube evaporation (VTE) desalination test project at the Salton Sea, to be conducted by Sephton Water Technology (SWT). The purpose of this project is to demonstrate the feasibility of controlling the salinity, nutrient, selenium, and other contaminant content of seawater by using geothermal waste steam to drive a VTE desalting system. The project satisfies one of the principal goals of the California Desalination Task Force, which is to identify potential opportunities for brackish water desalination, as well as the Energy Commission's need to improve the energy efficiency of water and wastewater treatment facilities in California. The project also addresses the problem of concentrate disposal. In this case, the plan calls for the concentrate to be pumped "down hole" to help recharge the geothermal aquifer, resulting in zero liquid discharge from the desalting plant (Energy Efficiency Division).

National Programs

Implementation of the U.S. Bureau of Reclamation's Desalination Roadmap
In 2001, Congress directed the Bureau of Reclamation to work with Sandia National Laboratories (SNL) to develop a desalination technology research plan for the United States. With the help of a multidisciplinary committee of representatives from academia and the public, private, and non-profit sectors***, The Desalination and Water Purification Technology Roadmap: A Report of the Executive Committee (Roadmap)*** was published in January 2003. The ***Roadmap*** presents a summary of water supply challenges facing our nation through 2020 and suggests areas of research that could lead to technological solutions for these challenges. The ***Roadmap*** may be used as a planning tool to facilitate science and technology investment decisions or as a management tool to help coordinate research efforts. To develop a mechanism to implement the recommendations of the Desalination Roadmap, the Joint Water Reuse and Desalination Task Force (JWR&DTF) was formed and is conducting workshops to establish a desalination research funding process. The Energy Commission was a member of the JWR&DTF planning committee that organized these workshops, and will participate in these workshops in the near future (Energy Efficiency Division).

Working Group on Concentrate Management Guidelines for Desalination and Water Reuse
Both the U.S. Bureau of Reclamation's ***Desalination and Water Purification Technology Roadmap,*** published in 2003, and the California Desalination Task Force identified concentrate management as a major area where research is needed to create next-generation desalination technologies. To help address the identified technical and environmental concerns associated with desalination and water reuse concentrate, Sandia National Laboratories initiated an effort, in cooperation with the Bureau of Reclamation, the American Water Works Association, the American Society of Civil Engineers, and the Water Reuse Foundation, to jointly develop guidelines for concentrate management. Energy Commission staff actively participate in the Concentrate Management Working Group, which is working on these guidelines (Energy Efficiency Division).

National Salinity Management Conference
This high-profile annual national conference is jointly sponsored by Multi-State Salinity Coalition, the US Desalination Coalition, the Northern California Salinity Coalition, the Water Reuse Association, the Southern California Salinity Coalition, and others in conjunction with the Nevada Water Reuse Association. It includes invaluable presentations, industry tours, and roundtable discussions on technical, policy, and program issues concerning energy issues in desalination. Energy Commission staff are regular members of the planning committee for this conference (Energy Efficiency Division).

Water Treatment

Developing and Validating an Energy Efficient Arsenic Removal Process
The current EPA standard for arsenic, a naturally occurring contaminant in groundwater, is 50 parts per billion (ppb). Effective January 2006, federal standard for arsenic in drinking water will be lowered to 10 ppb. The new arsenic standard will leave many public drinking water supply systems out of compliance, including several hundred systems in California. California has set a long-term public health goal for arsenic in drinking water at 4 parts per trillion (ppt) -- 2,500 times lower than the new federal standard of 10 ppb.

To attain this standard, the water systems in California will have to first meet the EPA standards in a cost-effective manner. Currently, the average cost of lowering arsenic from 50 ppb to 10 ppb from drinking water is in the range of $58 to $237 per household per year. Lawrence Berkeley National Laboratory is conducting research on an innovative medium, which, if successful, will lower the arsenic removal cost to $1 per household per year and have little or no incremental energy costs over current practices (PIER Industry, Agriculture and Water).

Wastewater Treatment

Development and Demonstration of a Digital System for Control and Mentoring of Oxygen Transfer Efficiency (OTE) Measurements
The majority of wastewater treatment plants nationwide uses an activated sludge secondary treatment process. Blowing air into the activated sludge aeration tanks accounts for 50 to 80 percent of a wastewater treatment plant's entire energy consumption. Over time, the diffusers through which this air blows become fouled by bacterial slime growth and scale buildup from hard water. One of the challenges of the wastewater industry is to monitor in real time the performance of wastewater treatment and how well aeration systems function.

Aeration system performance can be correlated with power consumption and calculated from material balances, but these results are not obtained in real time and can take weeks or months to obtain. A much better method is to measure OTE directly, using data collected from an instrument that measures oxygen in the gas released from the surface of the aeration basin. Currently, commercially available OTE instruments are large, heavy, and fragile, and require a crew of several people to operate. The purpose of this project is to design and demonstrate a new digital, fully-automated off-gas testing technology for purposes of evaluating and optimizing oxygen transfer efficiency, which would reduce energy demand (PIER Industry, Agriculture and Water).

Water-Related End Uses

Several projects underway are looking at ways to reduce the energy consumption of water-related end uses. Other efforts are focusing on increasing water use efficiency.

Waste Not, Want Not: The Potential for Urban Water Conservation in California
In 2003, the Pacific Institute published a report that quantified the unrealized potential for cost-effective water conservation in California. The report estimated that nearly 30 percent of potable water consumed in California – as much as 2 million acre-feet per year – could be cost-effectively conserved. In the context of the Pacific Institute's report, cost-effective is defined as "… the point where the marginal cost of the efficiency improvements is less than or equal to the marginal cost of developing new supplies."

Energy Down the Drain -The Hidden Costs of California's Water Supply
In the western United States there is a close connection between water and power resources. Water utilities use large amounts of energy to treat and deliver water, and even after utilities deliver water, consumers use even more

energy to heat, cool, and use it. This August 2004 report from the National Resources Defense Council (NRDC) and the Pacific Institute shows how water planners in California have largely failed to consider the energy implications of their decisions, and suggests a model for policymakers to calculate the amount of energy consumed during water use. Integrating energy use into water planning can save money, reduce waste, protect the environment, and strengthen the economy.

Water for Growth: California's New Frontier
According to the Public Policy Institute of California, which issued this report in July 2005, California’s population grew by over 10 million between 1980 and 2000. It is expected to increase by another 14 million by 2030, reaching a total of 48 million by that date. One of the most serious concerns of policymakers is whether the state will be able to supply enough water to support a population of this size. If per capita urban water use remains at its 2000 levels of 232 gallons per person per day, California will face an expansion of water demand of 40 percent, or 3.6 million acre-feet, by 2030. Policymakers and water planners have begun to consider several ways to bring supply and demand into balance over the years ahead. Options include expansion of nontraditional sources of supply (for example, underground storage, recycling, and desalination), reallocation through water marketing and conservation incentives and regulations.

California Water 2030: An Efficient Future
On September 13, 2005, the Pacific Institute released its newest report on the potential for saving water in California by 20 percent over the next 25 years while satisfying a growing population, maintaining a healthy agricultural sector, and supporting a vibrant economy. The report discusses how smart technology, strong management, and appropriate rates and incentives can allow the state to meet its needs well into the future, using less water.

The Irrigation Training and Research Center (ITRC)
The Irrigation Training and Research Center (ITRC) was established in 1989 at California Polytechnic State University, San Luis Obispo, as a center of excellence built upon a history of contributions to agriculture. The ITRC has a number of ongoing programs to develop and promulgate irrigation best practices in California. While ITRC’s research focuses on irrigation for agriculture, the tools, technologies, and techniques are often applicable to landscape irrigation as well (PIER Industry, Agriculture and Water).

California Urban Water Conservation Council (CUWCC)
The CUWCC is a non-profit organization created to increase efficient water use statewide through partnerships among urban water agencies, public interest organizations, and private entities. The Council's goal is to integrate urban water conservation BMPs into the planning and management of California's water resources. Presently, more than 300 urban water agencies

and environmental groups are signatories to a historic memorandum of understanding pledging to develop and implement 14 comprehensive water conservation BMPs. To the extent that the state adopts a policy allowing energy utilities to invest in water savings for their energy and environmental benefits, CUWCC's goals and activities are certainly in direct alignment.

Residential Hot Water Distribution System Research Project
The purpose of this project was to conduct a scoping study to establish the first-order estimate for the water and energy wasted in hot water distribution systems in California and the United States. This study found that the losses in residential hot water distribution systems total more than $1 billion per year in California and $10 billion per year in the United States, including the cost of energy, water, and wastewater treatment. A roadmap to identify future activities was part of the original project but has not been completed (PIER Buildings).

Testing of Hot Water Distribution Systems
The purpose of this project was to systematically test the performance of hot water distribution systems. Field work assessing the types of distribution systems in current construction practice was combined with laboratory testing. Test procedures were developed and used on ½- and ¾-inch copper piping and ¾-inch PEX-Aluminum-PEX piping. Tests were conducted in air on both uninsulated and insulated pipe. The results of this project will be combined with additional testing to support the 2008 Title 24 Residential Building Energy Efficiency Standards proceeding (PIER Buildings).

Water Heating R&D for the 2008 Residential Building Energy Efficiency Standards
This research will provide hot water distribution system data, analysis, and recommendations to the 2008 Title 24 Residential Building Energy Efficiency Standards proceedings. Specific efforts will inform the building standards proceeding in the areas of multi-family water heating, hot water pipe losses, single family water heating construction practices, and hot water distribution system modeling. This project will also study California housing's current hot water performance issues and cost-effective retrofit opportunities, and identify future research priorities for hot water distribution systems (PIER Buildings).

Super Efficient Gas Water Heating Appliance Initiative
This research will develop the foundation for a multi-year initiative to determine the best approach for achieving a 30 percent efficiency improvement in gas water heaters. Technical and market analysis will be conducted, along with stakeholder involvement, to implement a product development competition that develops and tests prototypes for safe, reliable, and cost-effective replacements for natural gas water heaters (PIER Buildings).

Market and Technical Considerations for a Next Generation Instantaneous Water Heater

Gas-fired instantaneous water heaters are highly efficient and can play an important role in reducing energy consumption. The barriers to the current generation of instantaneous water heaters include higher initial cost, installation cost adders, water waste associated with start-up, the inability to adjust to low flow rates or relatively warm incoming cold water, and the inability to meet large household or simultaneous demands. The goal of this research is to determine if current state-of-the art instantaneous water heaters can meet both current and projected California domestic hot water needs and to identify technology(ies) that can be incorporated into instantaneous water heaters to overcome current market and technical barriers (PIER Buildings).

Energy Efficiency Potential of Gas-Fired Commercial Water Heating Equipment

The goal of this research is to establish representative gas loads for both the installed base and higher-efficiency hot water systems in commercial kitchens, based upon a review of current literature monitoring data for three commercial food service sites (a quick-service, full-service, and institutional facility). This field experience will form the basis for a design guide for hot water systems in commercial food service (PIER Buildings).

Water for Electricity Generation

Water is used to generate electricity, both directly in hydropower plants and indirectly as part of cooling systems in thermal electric facilities. The Energy Commission has funded several projects to evaluate ways to reduce the effects of electricity generation on California's freshwater supplies and on aquatic species and habitats.

The Ecological Effects of Pulsed Flows from Hydropower Plants

The Center for Aquatic Biology at the University of California, Davis, is conducting research addressing the ecological effects of ramping and other pulsed flows from hydropower plants. These discharges are results of load following, sediment and vegetation management, and recreational requirements. Seven different projects are evaluating a wide range of issues, from the effects of these flows on invertebrates residing in stream and river bed sediment to the effects on the potentially threatened foothill yellow-legged frog. The purpose of this research is to provide information that will prompt regulatory decision making that would not otherwise be accomplished within the regulatory process. The information from this research will be used by regulators to establish information needs for impact assessment, set impact thresholds, and establish suitable mitigation measures. Research partners include the State Department of Water Resources, California Department of Fish & Game, PG&E, EBMUD, and NOAA Fisheries (PIER Environmental).

Development of Bioassessment Criteria for Hydropower Operation
The California Department of Fish and Game is conducting research to develop environmental indicators, using benthic macroinvertebrates, to assess and monitor the effects of hydropower operation on rivers and streams. The purpose of this project is to establish a low-cost assessment and monitoring tool that will provide a direct indication of ecosystem health, as opposed to relying upon indirect factors such as water temperature or flow. Research partners include the California Department of Fish and Game, California State Water Resources Control Board and California State University, Chico (PIER Environmental).

Integrated Forecast and Reservoir Management Project
Runoff and stream flow forecasting has historically relied upon limited hydrologic records. With the development and refinement of global circulation models and an improved understanding of climate conditions and their ramifications for California, future runoff probabilities can be more accurately predicted. Using these forecasts on an hourly to seasonal basis can result in better planning and optimization of California's water resources. The Energy Commission is funding a demonstration of this approach for four Northern California reservoirs: Shasta, Trinity, Oroville, and Folsom. This effort uses global circulation model scenarios, downscaled to hydrologic models, that encompass the catchments of each of these reservoirs, as well as the entire Sacramento River. This information is used to create probabilistic forecasts on an hourly to month-long basis. Since these major reservoirs are all multi-purpose, the project includes the development of decision support models that will allow reservoir operators to make better decisions about the balance between flood control, water supply, hydropower generation, and instream flow requirements. Based upon a retrospective analysis of Folsom Reservoir using this methodology, the researchers showed that there could be a15 percent increase in hydropower generation. Research partners include the National Oceanic and Atmospheric Administration, CalFed, the Department of Water Resources, Sacramento Area Flood Control District, the U.S. Bureau of Reclamation and the Army Corps of Engineers (PIER Environmental).

Development of Seasonal Forecast of Hydropower Generation
Scripps Institute is developing seasonal forecasts of hydropower production in the Pacific Northwest and California. Since the amount of hydropower production in these two regions has a significant effect on the cost and availability of electricity within California, providing forecasts on a seasonal basis will improve energy planning, especially natural gas demand. Another aspect of this project is to develop seasonal temperature predictions for California based upon global circulation model simulations. This information will allow planners to predict whether an upcoming summer will be exceptionally severe and plan accordingly. Research Partners include the Western Electricity Coordinating Council (WECC), Pacific Northwest National Laboratory and the University of Washington (PIER Environmental).

Advanced Cooling Strategies and Technologies
This program is being managed by EPRI and addresses approaches for reducing freshwater consumption in the thermal generating sector. Specifically, the program addresses both the barriers to wider adoption of water conserving cooling technologies and alternative cooling technologies. These approaches, such as the use of air-cooled condensers, can substantially reduce the amount of water used within a power plant. There are, however, economic and performance issues to overcome before industry will adopt these approaches. Research partners include NETL, Reliant, AES and Crockett Cogeneration (PIER Environmental).

Ecological Effects of Cooling Water Intake Structures
Within California, a significant portion of in-state thermal electric generation is from coastal power plants that use once-through cooling, which uses millions of gallons of water per day. The intake of these vast amounts of cooling water, which is not evaporated, means that millions of the eggs, larvae, and other early life stages of fish, clams, and other aquatic species are destroyed by the heat transferred to the cooling water. The ecological effects of this once-through cooling are not known. In addition, there is a need to develop new assessment techniques and establish the suitability of innovative technology to reduce this impact. The Moss Landing Marine Laboratory, a part of California State University, San Jose, is managing the research program on this topic. Research partners include the California Costal Commission, the California Department of Fish and Game, NOAA Fisheries and the University of California, Santa Cruz (PIER Environmental).

RPS-Eligible Small Hydropower Resource Assessment
The purpose of this project is to assess the magnitude of in-conduit resources potentially available for greater small hydropower development in California. Specifically, the study focuses on irrigation and municipal water systems where no new appropriation or diversion is required, which retains RPS eligibility under the conditions of SB1078. This study does not cover new or incremental power at existing dams or other potential in-conduit resources such as industrial process water and municipal wastewater (PIER Renewables).

Use of a Down-Hole Pump as a Turbine-Generator
The purpose of this project is to demonstrate and assess the performance of a reverse operated down-hole pump commonly used in the oil and gas industry as a turbine-generator for power production. The unit will be demonstrated in a Northern California Power Agency injection well at the Geysers, where the feedstock will be treated wastewater used to replenish and extend the life of the region’s underground steam fields. If successful, this would provide a means of partially offsetting the cost of pumping wastewater to the injection site (PIER Renewables and GRDA).

APPENDIX B: 2001 CALIFORNIA ENERGY CONSUMPTION BY END USE

2001 California Energy Consumption by End Use

Sector	Description	Electricity (GWh)	Percent Related to Water	Natural Gas (million therms)	Percent Related to Water	Adjusted Electricity (GWh)	Adjusted Natural Gas (million therms)
AG & WP	Domestic Water Pumping	11,953	1.00	19	1.00	11,953	19
AG & WP	Crops	3,284	1.00	103	0.05	3,284	5
AG & WP	Irrigation Water Pumping	2,269	1.00	5	1.00	2,269	5
AG & WP	Livestock	1,216	0.50	15	0.50	608	8
RESIDENTIAL	Clothes Drying	5,769	1.00	145	1.00	5,769	145
RESIDENTIAL	Water Heating	2,352	1.00	1,079	1.00	2,352	1,079
RESIDENTIAL	Indirect Hot Water Heating for Clothes Washing	1,053	1.00	486	1.00	1,053	486
RESIDENTIAL	Washing Machine	726	1.00	0		726	0
RESIDENTIAL	Indirect Hot Water Heating for Dish Washing	686	1.00	316	1.00	686	316
COMMERCIAL	Water Heating	549	1.00	174	1.00	549	174
RESIDENTIAL	Evaporative Cooling	519	1.00	0		519	0
RESIDENTIAL	Solar Water Heating	18	1.00	7	1.00	18	7
COMMERCIAL	Cooling	12,916	0.50	66	0.50	6,458	33
MINING & CON	Oil and Gas Extraction	3,958	0.50	2,775	0.50	1,979	1,388
RESIDENTIAL	Dish Washing	2,008	0.50	0		1,004	0
INDUSTRY	Publishing and Broadcasting Industries	955	0.50	9		478	0
INDUSTRY	Printing and Related Support Activities	773	0.50	19		386	0
INDUSTRY	Nonmetallic Mineral Product Manufacturing	710	0.50	116		355	0
TCU	National Security and International Affairs	2,649	0.20	60	0.30	530	18
RESIDENTIAL	Residential Miscellaneous	24,419	0.05	168	0.05	1,221	8
COMMERCIAL	Commercial Miscellaneous	19,156	0.05	722	0.05	958	36
INDUSTRY	Petroleum Refining and Related Industries	7,194	0.05	1,464	0.05	360	73
COMMERCIAL	Refrigeration	6,771	0.05	5	0.05	339	0
INDUSTRY	Food Manufacturing, Beverage and Tobacco	4,939	0.05	390	0.50	247	195
INDUSTRY	Chemicals	3,674	0.05	226	0.05	184	11
RESIDENTIAL	Cooking	3,595	0.05	286	0.05	180	14
INDUSTRY	Electronic Components	3,261	0.05	39		163	0
INDUSTRY	Computer and Electronic Product Manufacturing	2,988	0.05	37	0.05	149	2
INDUSTRY	Plastics and Rubber Products Manufacturing	2,886	0.05	40		144	0
TCU	Telephone	2,289	0.05	3		114	0
INDUSTRY	Fabricated Metals	2,045	0.05	122	0.05	102	6
INDUSTRY	Transportation Equipment	1,960	0.05	84		98	0
INDUSTRY	Machinery Manufacturing	1,777	0.05	24		89	0
INDUSTRY	Miscellaneous Assembly Industry	1,300	0.05	14		65	0
INDUSTRY	Sugar and Canned, Dried, and Frozen Food	1,283	0.05	299	0.50	64	149
MINING & CON	Construction	1,213	0.05	22	0.05	61	1
INDUSTRY	Primary Metals	1,192	0.05	133	0.05	60	7
INDUSTRY	Pulp, Paper, and Paperboard Mills	1,149	0.05	110	0.50	57	55
TCU	Electric and Gas Services, Steam Supply	1,006	0.05	25	0.05	50	1
INDUSTRY	Lumber	951	0.05	56		48	0
INDUSTRY	Paper Products; Excludes SIC 261,262,263,266	895	0.05	51		45	0
INDUSTRY	Furniture and Fixtures	793	0.05	9		40	0

Sector	Description	Electricity (GWh)	Percent Related to Water	Natural Gas (million therms)	Percent Related to Water	Adjusted Electricity (GWh)	Adjusted Natural Gas (million therms)
TCU	Airports, Flying Field and Airport Terminal Service	771	0.05	5	0.05	39	0
COMMERCIAL	Cooking	758	0.05	141	0.05	38	7
INDUSTRY	Electrical Equipment, Appliance, and Component Manufacturing	646	0.05	7		32	0
MINING & CON	Mining (except Oil and Gas)	615	0.05	58	0.05	31	3
INDUSTRY	Textile Products	397	0.05	8	0.05	20	0
INDUSTRY	Textiles	386	0.05	65	0.05	19	3
INDUSTRY	Textile Products	183	0.05	14	0.05	9	1
RESIDENTIAL	Pool Heating	60		100		0	0
RESIDENTIAL	Hot Tub Fuel	168		93		0	0
RESIDENTIAL	Water Bed	2,150		0		0	0
INDUSTRY	Glass manufacturing	877		128		0	0
INDUSTRY	Cement, Hydraulic	1,636		38		0	0
RESIDENTIAL	Pool Pump	3,024		0		0	0
RESIDENTIAL	Solar Pool Heating	0		64		0	0
RESIDENTIAL	Refrigeration	13,282		0		0	0
RESIDENTIAL	Solar Heater Pump	97		0		0	0
RESIDENTIAL	Hot Tub Pump	901		0		0	0
TCU	Water Transportation	48		0		0	0
TCU	Pipeline	935		16		0	0
COMMERCIAL	Heating	2,625		670		0	0
COMMERCIAL	Indoor Lighting	31,568		0		0	0
COMMERCIAL	Office Equipment	1,405		0		0	0
COMMERCIAL	Outdoor Lighting	5,332		0		0	0
COMMERCIAL	Ventilation	9,325		0		0	0
STLT	Street lighting and Traffic Control	1,713		0		0	0
RESIDENTIAL	Central Air Conditioning	4,199		45		0	0
RESIDENTIAL	Color Television	3,425		0		0	0
RESIDENTIAL	Freezer	2,461		0		0	0
RESIDENTIAL	Furnace Fan	1,273		0		0	0
RESIDENTIAL	Room Air Conditioner	486		0		0	0
RESIDENTIAL	Central Space Heating	3,245		2,339		0	0
TCU	Other Local Transportation, Parking Garages	212		5		0	0
TCU	Trucking and Warehousing	545		2		0	0
TCU	Post Office	528		3		0	0
TCU	Shipping Terminals	262		1		0	0
TCU	Air Transportation, Carrier	121		2		0	0
TCU	Transportation Service	201		2		0	0
TCU	Telegraph Communication	6		0		0	0
TCU	Radio and Television	461		1		0	0
TCU	Cable TV	514		1		0	0
TCU	Railroad Transportation	143		3		0	0
TCU	Rapid Transit	400		5		0	0
TCU	Sanitary Service	2,012	1.00	27	1.00	2,012	27
	Totals	**250,494**		**13,571**		**48,012**	**4,284**
	Percent					**19%**	**32%**

This table comes from the California Energy Commission's Demand Analysis Office. The data are for 2001 and are based on energy utility reporting for that year. They also include self generation above 1 MW. The percent of the energy related to water was discussed by the WER Working Group on July 29, 2005. If we agreed that most of the energy was water related, we assigned it a 1. If we knew there was a relationship but didn't understand enough to know how big, we assigned it 0.05. If there was some intermediate relationship, we assigned it 0.5, except for National Security and International Affairs which we felt was typical of the overall energy relationship to water. We assigned zero to those categories where there did appear to be a relationship.

APPENDIX C: ENERGY IMPACT ANALYSIS OF EXISTING WATER MANAGEMENT PRACTICES

Introduction

This appendix examines various water management practices focused on water conservation and efficiency and estimates the effects of water efficiency activities on energy savings. The analysis in this appendix is intended to:

- ✓ Quantify energy requirements in water use cycle processes.
- ✓ Determine current water efficiency measure energy impacts.
- ✓ Compare water and energy efficiency program characteristics.
- ✓ Recommend policy changes to incorporate water efficiency in the energy efficiency portfolio.
- ✓ Identify areas of research to better understand water-energy interdependencies.

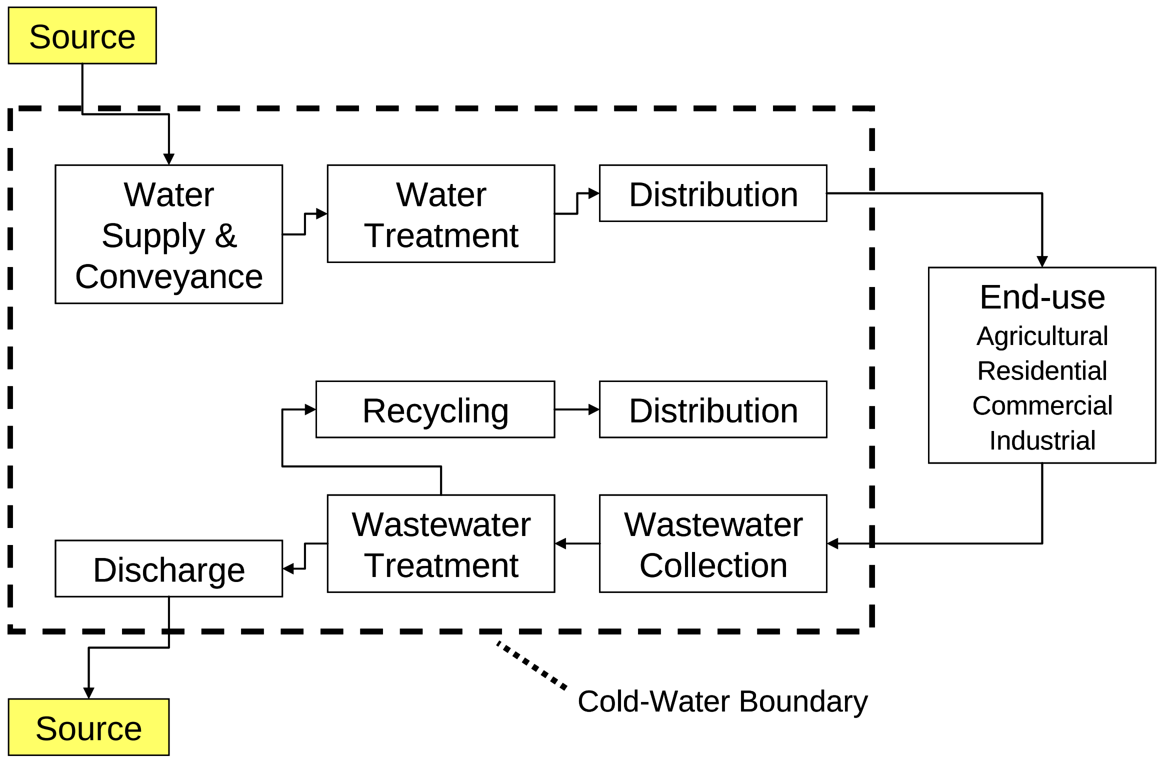
The Water Use Cycle

Electric and natural gas energy efficiency programs focus primarily on the application of energy consuming end-use technologies at utility customer facilities. In contrast to conservation, where usage is reduced through end-user behavioral changes, energy efficiency program planners target more permanent efficiency gains through known end-use technology or design applications. Likewise water use efficiency is achieved by implementing measures that result in reduced water consumption without customer behavioral changes.

In water systems, energy utilities target efficiency gains primarily by improving heating and pressurizing processes. For example, a low-flow showerhead saves energy because less hot water is used, thereby reducing the amount of energy needed to heat water. This is the case for water efficiency measures included in past energy efficiency programs such as faucet aerators, high-efficiency washing machines, and restaurant pre-rinse valves. Energy efficiency programs target efficiency gains in pressurizing applications by improving electric motor and/or pump efficiencies often at water and wastewater utility facilities. In each case the application is an end-use energy consuming technology located behind a customer meter.

When a unit of water is saved, so too is the energy required to convey, treat, deliver, perform wastewater treatment, and safely dispose of that unit of water. The energy intensity of the water use cycle must be examined on a systemic basis and varies widely by delivery location. Figure C-1 identifies the boundary of the water use cycle, showing the water processes that require energy, defined as cold water energy.

Figure C-1 Water Use Cycle



Significant customer-end use energy and water efficiencies have been, and are yet to be, achieved in the water sector[66]. These customer end-use efficiencies, while important, are excluded from this analysis to bring visibility to incremental cold-water energy savings.

When a water efficiency measure is implemented, the cold-water energy savings are achieved at multiple locations often transcending utility, city, and county jurisdictional boundaries. This analysis addresses the integration of water and energy demand-side management to increase cold water energy efficiency gains.

Water Use Cycle Energy Requirements

Electricity used to move or process water supplies (described above as cold water related energy) is quantified below in four primary stages or processes: conveyance, treatment, distribution, and wastewater treatment. The following table documents

[66] Even after accounting for expectations from existing efforts in this area, an additional 30-50 percent urban water (and associated energy) savings are possible with cost-effective existing technologies. (Waste Not, Want Not: The Potential for Urban Water Conservation in California, Pacific Institute, 2004.)

ranges of energy intensity for each process in terms of kilowatt-hours (kWh) per million gallons (MG):

Table C-1 Range of Energy Intensities for Water Use Cycle Processes (kWh/MG)

Water Cycle Segments	Low	High	Assumptions (Numbers in parentheses refer to sources listed below in this table)	
1. Water Supply & Conveyance	0	14,000	0: 14,000:	(1) Assume total gravity feed; (2) pg. 27 - SWP @ Pearblossom 4,444 kWh/AF or 13,638 kWh/MG (14,000 kWh/MG)
2. Water Treatment	100	16,000	100: 16,000:	(3) Water treatment without raw water pumping (max. gravity feed) and distribution pumping (accounted for under Distribution) = 99.7 kWh/MG Table 2-1, page 2-3 (7) Sea Water Desalination
3. Water Distribution	700	1,200	700:	(6)
			1,200:	(3) High Service Pumps To Distribution - 12,055 kWh/day for a Typical 10 MGD Surface Water Treatment Plant - figure 2-1, page 2-2 equivalent to 1,205.5 kWh/MG
4. Waste Water Collection	-	-		This category has been incorporated into the next category.
5. Waste Water Collection & Treatment	1,100	4,600	1,100: 4,630:	(4) Electric Use of Total Plant Operations Exec-1 and pg. 5, Table 3 - Range from 1,073 kWh/MG to 4,630 kWh/MG (3) Influent wastewater pumping is included in wastewater treatment process; figures 3-2 and 3-3, pages 3-3 and 3-4, respectively
6. Waste Water Discharge	0	400	0: 400:	(1) assumes gravity ocean outfall; 400 ground water recharge (3) pg. 3-7
7. Recycled Water Treatment	-	-		(4)(5) Tertiary/Advanced Waste Water Treatment Included under range of Waste Water Collection & Treatment
8. Recycled Water Distribution	400	1,200	Range:	(5) Municipal Recycled Water Use in California 2002: 46% Ag. Irrigation; 21 % landscape irrigation; 10% ground water recharge; Industrial 5%. This accounts for 82% of all recycled water. Energy needed for these applications fall within the ranges of the energy needed for typical water distribution and ground water recharge 400 - 1200 kWh/MG.

Sources:
(1) - Water Energy Working Group Assumption
(2) - Methodology for Analysis of the Energy Intensity of California's Water Systems; LBL January 2000
(3) - Water & Sustainability (Volume 4): U.S. Electricity Consumption for Water Supply & Treatment, EPRI March 2002
(4) - Energy Benchmarking Secondary Wastewater Treatment and Ultraviolet Disinfection Processes at Various Municipal Wastewater Treatment Facilities, PG&E February 2002
(5) - DWR Water Facts No. 23
(6) - EBMUD 2003 Load Study by Navigant Consulting
(7) - California Water Plan Update 2005 Volume 2, Resource Management Strategies, Chapter 6 – Desalination. A 50 mgd seawater plant (approximately 50,000 acre-feet per year, or 16.25 billion gallons, assuming operations 90% of the time) would require about 33 MW of power. California Water Plan Update 2005 Volume 2, Resource Management Strategies, Chapter 6 – Desalination. This translates to about 5,200 kWh per acre-foot, or 16,000 kWh per million gallons

Regional Water-Energy Characteristics

The ranges of water use cycle energy requirements identified above vary significantly because of regional water system operating requirements. To project energy savings associated with unit volume reductions in water requires adoption of prototypical energy needs, incorporating the variability inherent in regional resource alternatives. Analysis in this appendix separates water energy regions broadly into the Northern and Southern California regions, but additional research to assess regional water-energy characteristics is needed (see Suggested Research Topics, below).

The Northern California Region: Contains the North Coast, San Francisco, Sacramento River, San Joaquin River, Tulare Lake and Central Coast[67] Hydrologic Regions as defined by the California Department of Water Resources. The Northern California region contains 42 percent of the state's population and 42 percent of urban residential and non-residential applied water[68]. The region is characterized overall by relatively higher annual precipitation than in Southern California and significant native ground and surface water resources.

The Southern California Region: Contains the South Coast Hydrologic Region; 53 percent of the state's population and 48 percent of urban residential and non-residential applied water[69]. The region is characterized by relatively low annual precipitation and limited native surface water resources and has historically relied heavily on groundwater and imported water to meet water demand.

Other Hydrologic Regions: Hydrologic regions not included in this analysis are the North Lahontan, South Lahontan and Colorado River Hydrologic Regions[70]. Future studies will need to refine analyses addressed herein and incorporate these regions.

For purposes of this analysis, the Northern and Southern California regions, as referred to in this appendix, include 95 percent of the state's population and 90 percent of urban residential and non-residential applied water.

Water Use Cycle Energy Intensity

Table C-2 reflects the variability between water use cycle energy requirements between Northern and Southern California.

[67] The Central Coast hydrologic region includes Santa Barbara and San Luis Obispo Counties that are served by the SWP Coastal Branch with transport energy intensity on-par with the SWP West Branch (water must be lifted over the coastal mountain range). For the purposes of this analysis, the Central Coast is included in the Northern California region because 80 percent of the population within the Central Coast Hydrologic region resides north and east of the mountain range in communities such as Salinas, Santa Maria, Santa Cruz, Lompoc, and Monterey.

[68] Department of Water Resources 2005 Water Plan Update, Volume 3, Chapter 1 Table 1-4. Year 2000 is referenced for all regional characteristics and is described (same reference Table 1-1, page 1-10) as the "Average Year" within the context of precipitation and Wet versus Dry Years.

[69] Ibid

[70] North Lahanton is the extreme northeast of the state; South Lahanton is the region east of the Sierra Nevada Mountains including Mono Lake, Owens Valley and Death Valley; Colorado River Hydrologic Region include eastern San Bernardino, Riverside and Imperial Counties.

Table C-2 Percent Electricity Use for Water System Components[71]

	Northern California	Southern California
Imported Water Supply	-	71%
Local Ground/Surface Water Supply	17%	6%
Local Distribution	26%	9%
Wastewater Treatment	56%	14%

As reflected in Table C-2, the majority of the water use cycle energy required for Southern California, due to imported water, is not present in Northern California. To define process energy savings from water unit volume reductions, representative applications have been adopted for each primary process type: conveyance, treatment, distribution, and wastewater treatment. Energy use scenarios adopted and supported here are based on prototypical values for each process type. For purposes of this analysis, north/south water conveyance energy requirements are addressed separately and water treatment, distribution, and wastewater treatment assumptions are constant.

Water Conveyance

Northern California: As described in Table C-1, the range of water energy intensity for supply and conveyance ranges from 0 to 14,000 kWh/MG. Zero is assumed for gravity-fed systems. Water supplies from native surface water and groundwater sources require much less energy per unit conveyed than in Southern California. Approximately 60 percent of Northern California's urban water requirements are met with surface water and 40 percent is met with groundwater[72]. Additionally, roughly 40 percent of the region's population is located in the San Francisco Hydrological Region, where much of the water is conveyed by gravity from higher elevation reservoirs.

In this analysis, a prototypical value for water conveyance for Northern California is taken from the raw water pumping requirements of surface water treatment, based

[71] Methodology for Analysis of Energy Intensity of California's Water Systems and An Assessment of Multiple Potentials Benefits through Integrated Water-Energy Efficiency Measures; Exploratory Research Project Supported by: Ernest Orlando Lawrence Berkeley Laboratory, California Institute for Energy Efficiency; Principle Investigator Robert Wilkinson, PhD. January 2000, pg-7.

[72] Surface water and groundwater supply percentages are calculated using Water Supply and Use information provided in the California Water Plan Update 2005, Volume 3 for the California Department of Water Resources' North Coast, San Francisco, Sacramento River, San Joaquin River, Tulare Lake, and Central Cost Hydrological Regions.

upon a survey of approximately 30,000 public water supply systems in the United States[73] (see Water Treatment, below) and is estimated at 150 kWh/MG[74].

Southern California: Groundwater meets 23 and 29 percent of Southern California's water demand in normal and dry years, respectively[75]. The Metropolitan Water District (MWD) of Southern California provides 85 percent of the region's water supply to 26 cities and water districts serving 18 million people[76]. MWD's *Integrated Resource Plan* cites goals to mitigate heavy dependence on imported water by balancing its supply portfolio between imports; storage and transfers; recycling; groundwater recovery; conservation; brackish and seawater desalination; and exchanges[77]. While the region's water agencies have compiled a wide array of water management tools and planning practices to bring local water resources on a more equal footing, the region remains dependent on imported water for at least 50 percent of its water supplies[78].

As water agencies develop and employ least-cost resources to meet regional water demands, imported water serves as the primary baseline or "marginal resource." The 2003 *Qualifying Settlement Agreement* enabled implementation of the "4.4 Plan," where California will reduce its use of Colorado River water from a high of 5.3 million acre-feet to its 4.4 million acre-feet annual apportionment, by year 2016[79]. For Southern California, State Water Project (SWP) water supplies from Northern California are treated as the marginal water resource. A brief description of SWP water delivery to Southern California follows:

> As the California Aqueduct moves water south along the west side of the San Joaquin Valley, four pumping plants raise it more than 1,000 feet before reaching the Tehachapi Mountains. Pumps situated at the foot of the mountains pump the water up 1,926 feet through tunnels, which take the water into the Antelope Valley. In the Antelope Valley, the aqueduct divides into two branches: the East Branch and the West Branch.

---

[73] Water & Sustainability (Volume 4) U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century, EPRI 2002, Page 2-3

[74] Ibid, Figure 2-1, page 2-2, Raw Water Pumping 1,205 kWh per day for a treatment plant with 10 MGD capacity; equivalent to 120.5 per MG; assumption is raised to 150 kWh/MG as a minimum prototypical energy requirement.

[75] Ibid, Chapter 5, page 5-3

[76] Ibid, pages 5-2 and 3.

[77] MWD presentation to the Water Energy Working Group April 8, 2005.

[78] Ibid, page 5-5

[79] Department of Water Resources 2005 Water Plan Update, Volume 3, Chapter 5, page 5-8

> The East branch carries water through the Antelope Valley into Silverwood Lake in the San Bernardino Mountains. From Silverwood Lake, the water flows through the San Bernardino Tunnel, through the Devil Canyon Power Plant before continuing on to the southernmost SWP reservoir, Lake Perris. East Branch water energy intensity, net of any SWP system generation, is 3,236 kWh per acre-foot, or 9,931 kWh per MG. Water in the West Branch flows through the Warne Power Plant into Pyramid Lake in Los Angeles County. From there it flows through the Angeles Tunnel and Castaic Power Plant into Castaic Lake, terminus of the West Branch. West Branch water energy intensity, net of any SWP system generation, is 2,580 kWh per acre-foot, or 7,918 kWh per MG[80].

For purposes of this analysis, the energy intensity of Southern California's dominant and marginal water source, averaged between the SWP East and West Branch, is 8,924 kWh/MG (rounded off to 8,900 kWh/MG).

Water Treatment

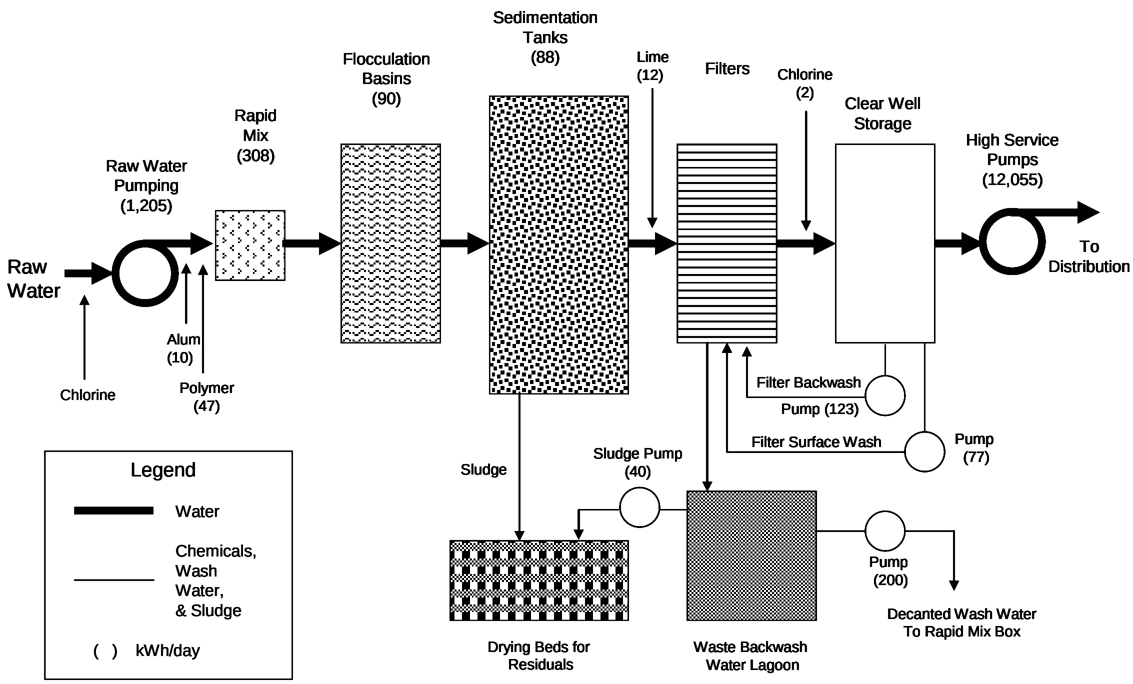
As explained above, for purposes of this analysis, water supply and conveyance energy requirements were addressed separately for Northern and Southern California. The remaining processes, water treatment, distribution, and wastewater treatment are considered similar enough between the two regions to assign the same prototypical water energy intensity. Due to the relative reliance on surface water supply in California, surface water treatment energy intensity has been adopted as prototypical.

In a typical sequence of operations for surface water treatment, the following steps are followed (see Figure C-2): Raw water is first screened and pre-oxidized, using chlorine or ozone to kill organisms; alum and/or polymeric materials are added to the water; flocculation and sedimentation remove finer particles; a second disinfection step kills remaining organisms with disinfectant residue carried into the distribution system to prevent organism growth; the clear well storage tank allows contact time for disinfection; and treated water is distributed to consumers by high-pressure pumps. Sludge and other impurities removed from the water are concentrated and disposed of.

[80] Methodology for Analysis of Energy Intensity of California's Water Systems and An Assessment of Multiple Potentials Benefits through Integrated Water-Energy Efficiency Measures; Exploratory Research Project Supported by: Ernest Orlando Lawrence Berkeley Laboratory, California Institute for Energy Efficiency; Principle Investigator Robert Wilkinson, PhD. January 2000, pages 24 through 27.

Figure C-2 Water Treatment Process Energy Requirements[81]

Representative Water Treatment Plant
Typical Daily Electricity Consumption for a 10 Million Gallon/Day Facility



Source: Electric Power Research Institute

[81] Water & Sustainability (Volume 4) U.S. Electricity Consumption for Water Supply & Treatment – The Next Half Century, EPRI 2002, Page 2-2, Figure 2-1.

Table C-3 Water Treatment Energy Intensity *(based on Figure C-2)*

		Surface Water Treatment Typical 10 mgd facility	kWh/MG
Public Supply	(Conveyance)	Raw Water Pumping	120.5
	(Treatment)	Alum	1.0
		Polymer	4.7
		Rapid Mix	30.8
		Flocculation Basins	9.0
		Sedimentation Tanks	8.8
		Lime	1.2
		Filters	0.0
		Chlorine	0.2
		Clear Well Storage	0.0
		Filter Backwash Pump	12.3
		Filter Surface Wash Pump	7.7
		Decanted Washwater to Rapid Mix	20.0
		Sludge Pump	4.0
		Treatment Subtotals	99.7
	(Distribution)	High Service Pumps	1,205.5
		Total	1,425.7

There is little variation in water energy intensity between plant sizes (shown in million gallons per day (MGD), as reflected in the following table:

Table C-4 Unit Electricity Consumption for Surface Water Treatment Plants[82]

Plant Size	kWh/MG
1 MGD	1,483
5 MGD	1,418
10 MGD	1,406
20 MGD	1,409
50 MGD	1,408
100 MGD	1,407

Referring back to Table C-3, in order to isolate the energy requirements for water treatment, the energy needed for raw water pumping and high service pumps to distribution have been removed. The remaining treatment processes total 997 kWh

[82] ibid, Page 2-3, Table 2-1. However, this study omitted the decanted wash water to rapid mix box pump rated at 20 kWh/MG from its totals. This amount was included in the numbers in the table.

per day for a typical 10 MGD capacity treatment plant or 99.7 kWh/MG. Actual energy requirements are driven by the site-specific characteristics of incoming raw water and water quality mandates. Industry standard practice, as well as process load metering, often doesn't differentiate raw water pumping, water treatment and distribution pumping loads adequately. Information provided in Table C-3 is drawn from large treatment plant populations and demonstrates this practice. Operational reporting of water treatment energy intensity is often driven more by the distance and elevation of the treatment plant in relation to water sources and the water distribution system than by the characteristics of raw water due to these vagaries. Typical water treatment processes are estimated at between 100 and 250 kWh/MG, and can be as high as 500 kWh/MG. In this analysis, 100 kWh/MG has been adopted as the prototypical and conservative water treatment energy intensity.

Water Distribution

Table C-4 shows there is little variation in the amount of energy required to treat and distribute a unit of water, regardless of plant size. As described above, Service Pumps to Distribution (for a typical 10 MGD water treatment plant) consume 12,055 kWh per day or 1,205.5 kWh per MG, or roughly 85 percent of total energy requirements (1,205 kWh/MG/1425 kWh/MG). For purposes of this analysis, a prototypical water distribution system energy intensity of 1,200 kWh/MG was adopted.

Wastewater Treatment

Unlike the water treatment and distribution systems, unit volume energy requirements for wastewater treatment plants vary greatly depending upon plant size. As would be expected, unit electricity consumption rises as the degree of treatment and complexity of the process increases. For example, advanced wastewater treatment with nitrification is three times as energy intensive (due to additional pumping requirements) as the relatively simple trickling filter plant[83]. Further complicating the assessment of prototypical wastewater treatment energy intensity are unique operational environments, discharge limitations, influent characteristics, and permitted effluent limitations as well as variations in plant permitting cycles. Table C-5 shows wastewater treatment plant energy intensities reflecting a range of energy intensity for facilities operating in California and cited in studies. Based on this range, 2,500 kWh per MG has been adopted as the prototypical wastewater treatment energy intensity.

[83] ibid, Pages 3-4 & 5 and Table 3-1.

Table C-5 Wastewater Treatment Energy Intensity

	kWh/MG
Inland Empire Utilities Agency [A]	2,971
City of Santa Rosa [B]	2,920
East Bay Municipal Utilities District [C]	2,001
Metropolitan Water District [D]	2655
Methodology for Analysis of Energy Intensity in California's Water Systems [E]	1,911
Energy Down The Drain, The Hidden Costs of California's Water Supply [F]	2,302
Energy Benchmarking Secondary Wastewater Treatment [G]	2,625

[A] Average of Five Wastewater Treatment Plants, CALeep Program Analysis May 2005
Program 1241-04, Conducted under the Auspices of the California Public Utilities Commission

[B] Laguna Wastewater Treatment
Sonoma County August 2002 Greenhouse Gas Emission Analysis, Page B-7

[C] EBMUD Load Studies Prepared by Navigant Consulting, December 2004

[D] The Metropolitan Water District of Southern California estimates that the wastewater facilities
in its service territory consume between 1,470 to 3,840 kWh/MG

[E] Methodology for Analysis of Energy Intensity in California's Water Systems, January 2000, P. 43
Wastewater Treatment Plants with Nitrification
Ernest Orlando Lawrence Berkeley Laboratory
Principal Investigator: Robert Wilkinson, Ph.D.
Ref.: Burton, Franklin L. (Burton Engineering) , 1996 Water and Wastewater Industries
Electric Power Research Institute Report CR-106941, p. 2-45

[F] Wastewater Treatment with Nitrification (average 1-100 mgd plant capacities)
Energy Down The Drain, p. 26

[G] Energy Benchmarking Secondary Wastewater Treatment and Ultraviolet Disinfection Processes
at Various (nine) Municipal Wastewater Treatment Facilities, PG&E February 2002
Electric Use of Total Plant Operations Exec-1 and pg. 5, Table 3 - 1,073 kWh/MG
Electric Use of Total Plant Operations Exec-1 and pg. 5, Table 3 - 4,630 kWh/MG

Summary of Water Energy Intensity for Northern and Southern California

The rest of this analysis is based on the following estimated energy intensities per million gallons of water (kWh/MG) delivered, treated, distributed, and disposed of in Northern and Southern California:[84]

[84] ibid (In this example NorCal system-wide Supply is estimated at 30 percent).

Table C-6 Prototypical Water Use Cycle Process Energy Intensity

	Northern California kWh/MG	Southern California kWh/MG
Water Supply and Conveyance	150	8,900
Water Treatment	100	100
Water Distribution	1,200	1,200
Wastewater Treatment	2,500	2,500
Total	3,950	12,700
Adopted	4,000	12,700

The Energy Efficiency of Water Use Efficiency

Energy savings associated with water savings provided in Table C-7 support the inclusion of water efficiency measures in energy efficiency program portfolios because of their relative low cost, long service life, and high resource value in terms of the avoided cost of energy. The following table reflects traditional water efficiency measures and their associated cold water energy savings resource values.

Table C-7 Water Efficiency Measure Cold Water Energy Savings

			Northern California			Southern California		
	Annual Savings Gallons/Year	Service Life	Annual kWh	Life-Cycle kWh	Resource Value	Annual kWh	Life-Cycle kWh	Resource Value
Residential								
Toilet Replacement 1.6 gpf (pre-1992)	2,250	25	9	225.0	$9	29	714	$32
Ultra Low-Flow Toilets	11,340	25	45	1,134.0	$44	144	3,600	$159
Energy Star Washing Machine	7,866	15	31	471.9	$27	100	1,498	$81
Commercial								
Ultra Low Flush Urinals	13,323	25	53	1,332	$52	169	4,230	$187
Waterless Urinals	25,568	25	102	2,557	$101	325	8,118	$359
Cooling Tower Condition Meter	729,906	10	2,920	29,196	$1,961	9,270	92,698	$5,609
Pre-Rinse Spray Head Installation	87,120	5	348	1,742	$136	1,106	5,532	$395
X-Ray Processor	1,042,723	5	4,171	20,854	$1,627	13,243	66,213	$4,733

Cost-effectiveness Assumptions

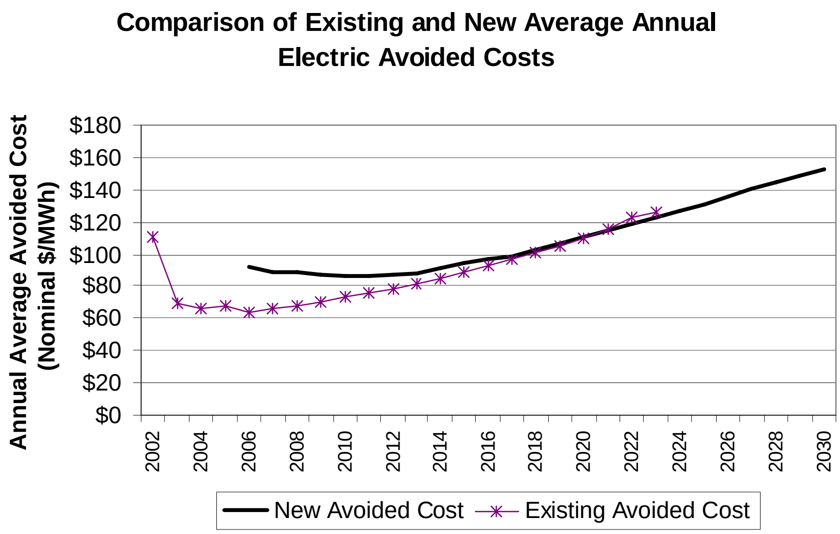
Resource values in this appendix were developed using the E3 Avoided Cost Methodology adopted by the California Public Utilities Commission (CPUC) in the April 7, 2005, Decision 05-04-024, Rulemaking (R.) 04-04-025. The CPUC adopted the E3 methodology for purposes of evaluating energy efficiency programs in R.01-08-028 and related energy efficiency proceedings.

The E3 model incorporates market price effects; the value of reliability through ancillary services; and the disaggregation of the avoided costs to time (hour, month, or time-of-use period) and to California climate zones. The E3 model forecasts the avoided costs of electric generation, transmission, and distribution that vary by hour, and the avoided costs of natural gas procurement, transportation, and delivery, which vary by month. Transmission and distribution (T&D) costs vary by utility service territory, planning division, and by the 16 Title-24 climate zones. Externality adders report environmental externalities: a T&D adder, which captures incremental demand-related capital expenditures, line losses and maintenance costs associated with increased energy use; a system reliability adder, which includes the cost of maintaining a reserve margin; and a price elasticity of demand adder, which recognizes that reduced demand results in a decrease in market-clearing price for electricity and therefore an increase in consumer surplus. The price elasticity of demand estimate varies by time-of-use period and month.

As currently utilized by the CPUC and energy utilities, the avoided cost projections in the E3 methodology extend to 2025. The calculations in this appendix include water use efficiency measures with 25-year service lives requiring that avoided cost projections be extended to 2030. The energy utilities submitted advice letter filings to the CPUC in April 2005 for purposes of updating their avoided cost projections. These filings projected utility avoided costs through 2030 for incorporation into the E3 methodology for valuing their energy efficiency resources. Figure C-3[85] compares the average utility avoided cost in place before and after the advice letter filings.

[85] Figure comes from E-3 published analysis of new and existing utility avoided costs.

Figure C-3



Source: E3

To calculate the resource value associated with the water use efficiency measures, the E3 methodology was modified to extend avoided cost projections to 2030. The adjustment from a 20-year to a 25-year measure results in less than a 7 percent change in the stated energy resource values. This means that the significant resource value potentials identified later in this appendix are not contingent upon modifying the avoided cost projections. E3 reviewed the adjustments and agreed the calculations were performed correctly.

Cold water energy savings are realized when one or more elements of the water use cycle - water conveyance, water treatment, water distribution systems and wastewater treatment facilities - process less water. They are also realized by avoiding incremental growth and requirements for plant expansions. In both cases the energy savings in the water use cycle result from the water use efficiency measures that were implemented. In this analysis water use cycle processes are assumed to operate 24 hours per day with an 85 percent load factor.

Energy Value of 2004 Best (Water) Management Practices

At a programmatic level, the California Urban Water Conservation Council (CUWCC) was created through the *Memorandum of Understanding (MOU) Regarding Urban Water Conservation in California* in 1991 to manage the process of implementing and updating the list of Best [water] Management Practices (BMP). To date 189 water agencies have pledged to implement the BMPs. CUWCC BMPs serve as a framework to quantify the energy resource value associated with water efficiency. The current lists of BMPs developed by the CUWCC follow.

Table C-8 CUWCC Best Management Practices[86]

BMP	Quantifiable Results
BMP 01: Water Survey Programs for Residential Customers	X
BMP 02: Residential Plumbing Retrofit	X
BMP 03: System Water Audits, Leak Detection and Repair	
BMP 04: Metering with Commodity Rates for all New Connections and Retrofit of Existing	X
BMP 05: Large Landscape Conservation Programs and Incentives	X
BMP 06: High-Efficiency Washing Machine Rebate Programs	X
BMP 07: Public Information Programs	
BMP 08: School Education Programs	
BMP 09: Conservation Programs for CII Accounts	X
BMP 09a: CII ULFT Water Savings	X
BMP 10: Wholesale Agency Assistance Programs	
BMP 11: Conservation Pricing	
BMP 12: Conservation Coordinator	
BMP 13: Water Waste Prohibition	
BMP 14: Residential ULFT Replacement Programs	X

Source: California Urban Water Conservation Council

[86] Quantifiable means annual reported BMP water use efficiency savings in acre feet per year, net of plumbing code compliance savings, reported pursuant to the 1991 Memorandum of Understanding Regarding Urban Water Conservation in California under protocol set forth by CUWCC. References: CUWCC (2005) *BMP Costs and Savings Study - A guide to Data and Methods for Cost-Effectiveness Analysis of Urban Water Conservation Best Management Practices* and (2003) *First Partial Revision*; M. Cubed (2003) *BMP Reporting Database Water Savings Calculations*; M. Cubed (1997) *California Urban water Agencies BMP Performance Evaluation, Final Report*; A&N Services (1996) *Guidelines to Conduct Cost-Effectiveness Analysis of Urban Water Conservation Best Management Practices*; U.S. EPA (1994) *Customer Incentives for Water Conservation, A Guide,* EPA/X820683-01-1, U.S. Environmental Protection Agency, Washington, DC. Measurement and evaluation is addressed by the CUWCC Measurement & Evaluation Committee.

To provide visibility to the potential impacts of integrated resource planning for water and energy efficiency programs, 2004 water sector BMP achievements were examined using the adopted energy efficiency avoided cost valuation methodology[87]. This analysis combines known planning criteria from each industry to assess the efficiency gain potential though programmatic integration.

Quantifiable water savings are available for eight of the BMPs, as shown in Table C-8. Each BMP includes several related water use efficiency measures. Assumptions for the water savings of each measure in gallons per day (GPD) and measure service life are reflected below in Table C-9.

[87] Resource values are produced using the E3 Avoided Cost Methodology adopted by the CPUC in the April 7, 2005 Decision 05-04-024, Rulemaking (R.) 04-04-025. The Commission adopted the E3 Methodology for the purposes of evaluating energy efficiency programs in R.01-08-028 and related energy efficiency proceedings. Avoided cost bases are maintained at the website http://www.ethree.com/CPUC/cpucAvoided26.xls

Southern California Resource Values: The E3 calculator utilized is version "SCE Tool 1q" and incorporates SCE's update to the E3 Methodology as described in SCE Advice 1187-E (U-338-E) of April 25, 2005 specifically "extending the avoided cost forecast to 25 years from the base year of 2006" and applying "a linear trend based on the last five years of data contained in the E3 Methodology" as described in the referenced Advice Letter, page 3, Section A.

Northern California Resource Values; The E3 calculator utilized is version "CEE_Calc_Tool_Commercial_1d" and incorporates PG&E's update to the E3 Methodology as described in PG&E Advice 2626-G/2654-E (U-39-M) of April 25, 2205 and reflect ATTACHMENT A, Table 4: Adjustments Made to Extend Forecast through 2030.

Table C-9 BMP Water Use Efficiency Measure Service Life and Savings

	Service Life	Savings gpd	Reference
BMP 01:	4.5	26.6	Residential Surveys: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
	5	21.0	Residential Surveys, Single Family: Metropolitan Water District of Southern California (MWD) program planning assumptions
	4	8.8	Residential Surveys, Multi-Family: MWD program planning assumptions
BMP 02:	5.1		Residential Plumbing Retrofits: BMP Costs & Savings Study (July 2000 ed.), page 2-13, mid-point range, equivalent useful life five years April 28 2003 M. Cubed Technical Memorandum to M&E Committee re; BMP Reporting Database Water Savings Calculations - Page 4 of 15
	5	5.5	Low Flow Showerheads: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	3.5	4.2	Toilet Displacement Devices: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	2	1.5	Faucet Aerators: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	8.5	0.64	Toilet Leak Detection: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	8.5	0.5	Other Household Leak Detection: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	4	12.2	Turf Audit: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	4	25.9	Turf Audit With Timer: BMP Costs & Savings Study, First Partial Revision December 2003, page 2-38, Table 1 Method 1 average
	25	24.2	Ultra Low-Flow Toilets (ULFT): BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
	17.5		Hot Water on Demand: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
BMP 04:	10.5	Reported	Metering With Commodity Rates: BMP Costs & Savings Study, Draft Revision March 2005, page 2-29 (though should probable be 20+, as if and when a meter fails, it would be replaced see Section 2.5
BMP 05:	10	Reported	Large Landscape: Budgets and Surveys: MWD Planning Practices; BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range) see Section 2.16
			Evapotranspiration (Eto)-based budgets: BMP Costs & Savings Study (July 2000 ed.), Table 1, page 53
			Large Landscape Surveys: Urban Water Conservation Potential (August 2001)
BMP 06:	14	21.6	H/E Washing Machines: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
	15	21.6	BMP Costs & Savings Study, First Partial Revision December 2003, page A-6
		13.8	BMP Costs & Savings Study, First Partial Revision December 2003, page A-8 range average
BMP 09:	12.4		CII Conservation Programs: Urban Water Conservation Potential (August 2001) (decay rate 10%)
		527.5	CII Surveys: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
	5	2,856.8	X-Ray Processor: MWD Program Planning assumptions
	3	136.6	Water Broom: MWD Program Planning assumptions
	5	300.0	Pre-Rinse Spray Head: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range 100-500 gpd); expected life span see page 2-80
	3	200.0	MWD program planning assumptions
	5	240.0	PG&E Non-Residential Work Papers Supporting Application For Approval of 2006-2008 Energy Efficiency Programs and Budgets filed June 20 2005, R.01-08-028, pages 40 - 43 (electric) and 57 - 59 (gas) of 279, Non-Res Deemed Savings pages 14 or 20
	5	892.7	Industrial Process Improvement: MWD program planning assumptions
	8	103.6	High-Efficiency Washers: MWD program planning assumptions
	5	22.3	Flush Valve Kit: MWD program planning assumptions
	10	1,999.7	Cooling Tower Conditioning Meter: MWD program planning assumptions
BMP 09a:	25	36.5	CII ULFT Replacement: M. Cubed (2003) Technical Memorandum to the CUWCC M&E Committee re; BMP Reporting Database Water Savings Calculations - Page 10 of 15; BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range); BMP Costs & Savings Study, First Partial Revision December 2003, page A-12, Example 2A
	25	30.4	CII Dual Flush CII ULFT: MWD program planning assumptions
	30	30.1	Ultra Low-Flow Urinals: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
	25	70.1	Waterless Urinals: BMP Costs & Savings Study, Draft Revision March 2005, page 1-10 & 11, Table 1-3 (average of range)
BMP 14:	25	31.1	Res - ULFT: BMP Costs & Savings Study, First Partial Revision December 2003, page A-12, Example 2A; MWD program planning assumptions; BMP Costs & Savings Study (July 2000 ed.), page 2-29; April 2003 Technical Memorandum, page 15 of 15

Source: California Urban Water Conservation Council

The CUWCC reporting system for reductions in water used by member agencies reflects 2004 BMP achievements for BMPs with quantifiable results.[88] The energy savings for these measures, both annual and life cycle, are shown for each of these measures in Table C-10.

88 Data was obtained from public access CUWCC website http://bmp.cuwcc.org/bmp/summaries/public/bmpsavings.lasso

Table C-10 Energy Resource Value in Water Use Efficiency (2006-2008 (E3) Avoided Cost)[89]

Northern California (PG&E/SMUD)	MG	Annual Savings kWh	Useful Life	Life-Cycle kWh Savings	NPV Electric Avoided Cost
BMP 1 Water Survey Programs MF/SF	802	3,208,000	5	16,040,000	1,251,113
BMP 2 Residential Plumbing Retrofit	132	528,000	5	2,640,000	205,919
BMP 4 Metering & Commodity Rates	671	2,684,000	11	29,524,000	1,929,737
BMP 5 Large Landscape Conservation Programs	2,249	3,261,050	10	32,610,500	2,190,009
BMP 6 High-Efficiency Washing Machine Rebate	134	536,000	15	8,040,000	474,057
BMP 9 Conservation Programs CII	2,035	8,140,000	12	97,680,000	6,217,380
BMP 9a CII ULFT	109	436,000	25	10,900,000	430,340
BMP 14 Residential ULFT	5,490	21,960,000	25	549,000,000	21,674,941
Total Northern California	11,621	40,753,050			$34,373,496
Southern California (SCE/LADWP/SDG&E)					
BMP 1 Water Survey Programs MF/SF	1,095	13,906,500	5	69,532,500	4,969,753
BMP 2 Residential Plumbing Retrofit	180	2,286,000	5	11,430,000	816,946
BMP 4 Metering & Commodity Rates	916	11,633,200	11	127,965,200	7,543,053
BMP 5 Large Landscape Conservation Programs	3,072	31,334,400	10	313,344,000	18,959,692
BMP 6 High-Efficiency Washing Machine Rebate Program	183	2,324,100	15	34,861,500	1,872,831
BMP 9 Conservation Programs CII	2,779	35,293,300	12	423,519,600	24,350,142
BMP 9a CII ULFT	149	1,892,300	25	47,307,500	2,092,023
BMP 14 Residential ULFT	7,498	95,224,600	25	2,380,615,000	105,275,069
Total Southern California	15,871	193,894,400			$165,879,509
Total Statewide Impacts	27,492	234,647,450			$200,253,005

Source: CUWCC Reporting Database, April 2005 with 86 of 269 Reporting Units (32%) reporting BMP expenditures in 2004 Reporting Units include: Water utility districts, water agencies, irrigation districts, city and county water departments and, water service companies implementing BMPs.

The numbers shown in Table C-10 reflect the variability in water conservation impacts on water related energy requirements, depending upon measure location.[90] The energy values have been obtained based on the multipliers for Northern and Southern California. The landscape numbers assume that the applied water is not treated as wastewater. In addition to the more than 27 million gallons saved from the 2004 BMPs, 234 million kWh were also saved that year, worth more than $200 million over their useful lives.

At this time it is reasonable to use the energy intensity values contained in this appendix as proxy values to support program planning. Future analyses of water energy intensity should be refined geographically by applying characteristics of hydrologic regions, planning areas or detailed analysis units as required, and finally

[89] See footnote 83.

[90] Water conservation activity is reported by CUWCC aggregated; to support disaggregating between SoCal and NorCal, electric service customer populations were used to establish approximately 60 percent - 40 percent shares for SoCal and NorCal, respectively.

applied to a structure that will align with energy efficiency planning climate zones[91] (See Suggested Research Topics).

The need to measure location-specific water-energy efficiency impact does not constitute a programmatic barrier for energy efficiency planners. This treatment is consistent with current energy efficiency program planning practices. For example, all current weather-dependent energy efficiency measure savings reflect location-specific savings across 16 climate zones - for example heating; ventilation and air-conditioning as well as building envelope measures; insulation; window glazing; and infiltration. Therefore, adopting savings for water-energy efficiency reflecting regional water energy intensity could be readily incorporated into current energy efficiency program planning protocols. The key point is that regional variability in water energy intensity should not defeat integrated planning. Energy efficiency planning already addresses many efficiency measures with varying degrees of savings in 16 geographic climate zones.

Statewide Water Use Efficiency (WUE) Potential

While the energy saving potential of 2004 BMP results are significant, they in no way indicate statewide potential. As related above, this appendix relied on the CUWCC's reporting database and used CUWCC's BMP reporting structure to provide visibility for associated energy benefits. CUWCC stresses that the reported savings are conservative and "the database does not include water efficiency for a whole series of BMPs for which CUWCC did not have a method to calculate water savings"[92].

The Pacific Institute, in its November 2003 report *Waste Not, Want Not: The Potential for Urban Water Conservation in California*, cites water savings potential, reflected in Table C-11. The 2004 BMP reported results in Table C-10 that represent approximately 4 percent of the minimum potential cost-effective savings identified here.

[91] The California Department of Water Resources subdivides the state into 10 hydrological regions, 56 planning areas plus a more detailed breakdown into 278 detailed analysis units. Existing spatial analysis (GIS) readily supports integration of water measures into energy-efficiency program planning climate zones to ensure regional values align with energy-efficiency program planning protocols.

[92] Comments of Mary Ann Dickinson, Executive Director of the California Urban Water Conservation Council at the California Energy Commission Energy-Water Relationship Comment Workshop, Docket No. 04-IEP-01-H, June 21, 2005; Proceeding Minutes page 22.

Table C-11 California Urban Water Use in 2000

Potential to Improve Water Use Efficiency and Conservation

California Urban Water Use by Sector	Current (2000) Water Use (AF/year)	Best Estimate of Conservation (AF/year)	Potential to Reduce Use (%)	Minimum Cost-Effective Conservation (AF/year)
Residential Indoor	2,300,000	893,000	39	893,000
Residential Outdoor	983,000 to 1,900,000 (b)	360,000 to 580,000 (c)	25 to 40	470,000
Commercial/ Institutional	1,850,000	714,000	39	Combined CII: 658,000
Industrial	665,000	260,000	39	(e)
Unaccounted-for Water	695,000	(d)	(d)	(d)
Total	**6,960,000** (+/- 10%)	2,337,000	34	2,020,000

Source: The Pacific Institute

The question is really how much energy savings can actually be achieved through this much water use efficiency. The following calculations were performed to make this determination:

1. The average of *Best Estimate of [Water] Conservation* and *Minimum Cost-Effective Conservation* (Table C-11 above) is 2,178,500 acre feet per year, rounded to 2,150,000.
2. As shown in Table C-6 (and applied in Table C-11), the average energy intensity for Northern and Southern California is 4,000 and 12,700 kWh/MG, respectively; the weighted average based on customer populations is 9,220 kWh per MG[93].
3. 2,150,000 AF or 700,580 MG of California's achievable water conservation, multiplied by the 9,220 kWh per MG (the state's weight average water use cycle energy intensity), yields equivalent energy savings of 6,450 GWh, rounded to 6,500 GWh.

[93] The weight average of water use cycle energy intensity is based on year 2000 customer populations for Northern California of 5.167 million customers (PG&E and SMUD) and for Southern California of 7.057 million customers (SCE, LADWP and SDG&E) representing 92 percent of California's electric customers. This yields a customer allocation of 42.3 percent for Northern and 57.7 percent for Southern California. Applying the rounded allocation of 40 percent and 60 percent to respective energy intensities of 4,000 and 12,700 kWh per MG yields a population based weighted average of 9,220 kWh per MG.

4. 6,500 GWh and an 85 percent load factor yield a demand reduction of 873 MW, rounded to 850 MW.

   In Summary:

   - ✓ Annual water use efficiency water savings:
     - 700,580 MG
   - ✓ Water use cycle energy requirements:
     - 9,220 kWh/MG
   - ✓ Water use efficiency energy savings:
     700,580 (MG) X 9,220 (kWh/MG) = 6,459,344,373 kWh or 6,459 GWh
     Assumed Water Use Cycle Energy Savings = 6,500 GWh
   - ✓ Water use efficiency demand reduction:
     Peak Load (kW) = kWh / (Load Factor * 8760)
     Peak Load (kW) = 6,500,000,000 / (.85 * 8760) =
     873,000 kW or 873 MW
     Assumed Peak Load Reduction = 850 MW

5. Information from multiple sources shows that the cost of most water use efficiency measures ranges from about $58 to $710 per acre-foot or $178 to $2,179 per MG, depending upon the program. These costs include the full cost to manage the programs, capital investments, and required staffing[94]. Assuming an average of this range, or $384 per acre-foot ($1,178 per MG), the approximate cost in terms of energy efficiency is $0.13 per annualized kWh (700,580 MG X $1,178/MG = $825.6 million / 6,500,000,000 kWh = $0.127/kWh, rounded to $0.13/kWh).

Table C-12 presents the results of these calculations and compares them to the California's energy efficiency programs for 2004-2005 and those planned for 2006-2008.

[94] Department of Water Resources 2005 Water Plan Update, Volume 2, page 22-2, Potential Benefits of Urban Water Use Efficiency, and; Potential Costs of Urban Water Use Efficiency

Table C-12 Comparison of Water Use Efficiency to Energy Efficiency Resource Value

	2004-2005 [1]	2006-2008 [2]	WUE [3]
GWh (Annualized)	2,745	6,812	6,500
MW	690	1,417	850
Funding ($ million)	$762	$1,500	$826
Cost per Annual kWh	$0.28	$0.22	$0.13
WUE Relative Cost	46%	58%	

[1] CPUC Rulemaking R.01-08-028, Decision D.03-12-060
[2] CPUC Rulemaking R.-01-08-0228, Decision D.04-09-060
[3] California Water Plan Update 2005, Bulletin 160-05 California Department of Water Resources, page 22-2

The table shows that the estimated energy savings from statewide water use efficiency is more than double the energy savings from the 2004-2005 energy efficiency programs and almost as large as those planned for 2006-2008. The estimated peak reduction from water use efficiency falls between the values for these years. From a program cost standpoint, water use efficiency is roughly one-half the cost of energy efficiency programs.

These estimates are reasonably robust. If the energy savings were only half as much or if the costs were twice as much, water use efficiency would be as cost-effective as current and planned energy efficiency programs.

One of the questions that came up during the California Energy Commission's (Energy Commission) *Integrated Energy Policy Report (Energy Report)* proceedings was concerned with the different ways that water and energy programs address the useful life of the same measures. To evaluate the potential impact of this difference, Table C-13 compares several measures that are common to both energy efficiency and water use efficiency programs. The Estimated Useful Life (EUL) and energy savings from water heating and from savings in the water use cycle (cold water savings) are presented for four common measures:

Table C-13 Energy Efficiency – Water Use Efficiency Common Measures

	Energy - EUL	Water – EUL	Heating Annual Savings (kWh)	Cold Water Savings (kWh)
Low-Flow Showerhead[1]	10	5	202	16
Faucet Aerator[2]	10	2	78	4
Clothes Washer[3]	15	15	644	100
Pre-Rinse Spray Valve[4]	5	5	12,310	1,106

[1] Measure #504 California Statewide Residential Sector Energy Efficiency Potential Study #SW063
[2] Measure #506 ibid
[3] Measure #601 ibid
[4] PG&E CPUC Application for Approval of 2006-2008 Energy Efficiency Programs and Budget (U 39 M), Advice Letter 05-06-004 ATTACHMENT 4, ERRATA FOR PROGRAM DESCRIPTIONS, Workpapers

As shown above, water use efficiency planners apply estimated useful lives to the same measures that are either equal to or lower than those applied by energy efficiency planners. For purposes of consistency with the energy savings calculations shown later in this appendix, the EULs used by the energy planners were adopted.

Another concern was that these four measures represent the full potential for additional water use efficiency gains. However, the small set of overlapping measures represents less than 2 percent of the *known* energy savings and resource value that can be created through cold water savings. These additional savings – 98 percent - will come from measures that have been generally overlooked by energy efficiency planners.

At one time water use efficiency was narrowly viewed as a temporary source of water supply in response to drought or emergency water shortage situations. However, this analysis shows that water use efficiency is a viable long-term water and energy resource supply option. In short, significant, attainable energy savings can be realized in the form of water use efficiency.

Comparing Water and Energy Efficiency Programs

Comparing water and energy efficiency programs reveals differences in treatment in the following areas: program oversight, resource valuation, technical potential, budgets (trends), planning, implementation and evaluation, measurement, and verification. This section examines how both programs address these areas.

Program Oversight and Compliance

There is significant variability between water and energy efficiency program targets, regulatory oversight, and compliance. Targets for water conservation are referenced to a 10-year reporting period. Performance requirements for the BMPs with quantifiable results follow in Table C-14:

Table C-14 Best Management Practices

BMP	Requirements
BMP 01: Water Survey Programs for Single-Family and Multi-Family Residential Customers	Survey 15 percent of residential customers within 10 years
BMP 02: Residential Plumbing Retrofit	Retrofit 75 percent of residential housing constructed prior to 1992 with low-flow showerheads, toilet displacement devices, toilet flappers and faucet aerators
BMP 04: Metering with Commodity Rates for all New Connections and Retrofit of Existing	Install meters in 100 percent of existing un-metered accounts within 10 years; bill by volume of water use; assess feasibility of installing dedicated landscape meters
BMP 05: Large Landscape Conservation Programs and Incentives	Prepare water budgets for 90 percent of commercial and industrial accounts with dedicated meters; provide irrigation surveys to 15 percent of mixed-metered customers
BMP 06: High-Efficiency Washing Machine Rebate Programs	Provide cost-effective customer incentives, such as rebates, to encourage purchase of machines that use 40 percent less water per load
BMP 09: Conservation Programs for CII Accounts	Provide a water survey of 10 percent of these customers within 10 years and identify retrofitting options; OR reduce water use by an amount equal to 10 percent of the baseline use within 10 years
BMP 14: Residential ULFT Replacement Programs	Replace older toilets for residential customers at a rate equal to that of an ordinance requiring retrofit upon resale

Source: California Urban Water Conservation Council

A consistent and broadly acceptable method to evaluate (water use efficiency) cost-effectiveness and water savings is needed[95]. Documentation and evaluation of the achievements attributable to water use efficiency projects and programs, vital elements of successful water use efficiency efforts, need to be improved. The quantification of benefits for many projects lacks a necessary level of scientific

95 Ibid

rigor[96]. Implementation of the BMPs by the water agencies is voluntary, and water efficiency program performance is self-reported, monitored by the CUWCC[97]. CUWCC is a non-profit agency with its governance administered by a committee comprising six representatives: three representatives from member water agencies and three representatives from public advocacy organizations[98]. Not all water agencies have signed onto the MOU agreement, and not all signatories are fully implementing the BMPs[99].

In contrast, the state's investor-owned utilities (IOU) energy efficiency programs are regulated by the CPUC[100]. The requirements include:

- ✓ Administrative structure for efficiency programs
- ✓ Program evaluation, measurement, and verification (EM&V)
- ✓ Separation between "those who do" and "those who evaluate" programs
- ✓ Protocols for measuring efficiency programs are defined in the *Protocols and Procedures for the Verification of Costs, Benefits, and Shareholder Earnings from Demand-Side Management Programs* [101]
- ✓ EM&V integration into the program planning process
- ✓ EM&V funding guidelines
- ✓ The type and frequency of EM&V studies conducted for each program and the major study parameters utilized for each study, including sample design, monitoring duration and schedule, and approaches undertaken to evaluate and minimize bias
- ✓ Cost-effectiveness tests used to evaluate program performance and proposed programs including:

[96] Department of Water Resources 2005 Water Plan Update, Volume 2, page 22-4, WUE Challenges – Data Collection.

[97] CUWCC Governance Policies Section 10. Access to BMP Reporting Data: 10.1a.: "The Council will regard any data stored in the Council BMP Reporting Database that has been formally 'submitted as final" as public information', and; Section 10.1c.: "All publicly-released reports shall carry a disclaimer indicating that reports are based on self-reported data that has not been 100% validated by the Council."

[98] CUWCC Governance Policies Section 6.1, "The Council's Governance Committee shall be responsible for initiating the Executive Director's Annual Performance Review. The committee shall be responsible for oversight of Council governance, including review of bylaws, policies, membership development and training, communication (internal and external), strategic planning and meeting protocol." "The Governance Committee shall be composed of three Group 1 representatives (urban water supplier representatives) and three Group 2 representatives (public advocacy organizations) from the Steering Committee.

[99] Department of Water Resources 2005 Water Plan Update, Volume 2, page 22-3

[100] See CPUC Rulemaking 01-08-028, Decision 05-04-051 April 21, 2005

[101] As adopted by California Public Utilities Commission Decision 93-05-063 Revised March 1998 Pursuant to Decisions 94-05-063, 94-10-059, 94-12-021,95-12-054, 96-12-079, D.98-03-063, and D.99-06-052.

– program costs and participation levels
– number and type of measures
– environmental adders informed by and coordinated with the Climate Change Action Registry
– continuity of the input assumptions and calculations for the tests of cost-effectiveness (California Standard Practice Manual[102])
– *ex post* (after-installation) measurement of lifecycle savings inform and update *ex ante* (pre-installation) assumptions for future programs
– values for the weighted cost of capital (instead of using different values for each implementer). The current authorized cost of capital for the IOUs ranges between 7.6 percent and 8.7 percent, depending upon the IOU.

Program Funding

Variations in program oversight and compliance might reflect, in part, energy efficiency program ratepayer funding and funding levels. California electric industry deregulation legislation and other regulation established minimum levels of energy efficiency funding from 1998 through 2001, and are currently used by both IOUs and local publicly owned electric utilities[103].

Additionally, in 2003 the CPUC ordered IOUs to file plans to include energy efficiency as part of their long-term procurement supply portfolios for the first year, five years, and twenty years[104].

---

[102] http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/03eeproposalinfo.htm

[103] Electric Industry restructuring legislation Assembly Bill 1890 (Brulte, 1996) codified in Public Utilities Code (PU Code) under Division 1, Part 1, Chapter 2.3. Electrical Restructuring. Under Article 7 Research, Environmental, and Low-Income Funds, Section 381 directed the CPUC to require each IOU to identify a separate rate component to collect revenues used to fund cost-effective energy efficiency and conservation activities. Herein the IOUs were directed to fund not less than the following levels commencing January 1998 through 2001 ($ million dollars):

	1998	1999	2000	2001	Total
SDG&E	$32	$32	$32	$32	$128
SCE	$90	$90	$90	$50	$320
PG&E	$106	$106	$106	$106	$424
Total	$228	$228	$228	$188	$872

Article 8, Section 385 (a) directs each local publicly owned electric utility to establish a non-bypassable, usage based charge on local distribution service of not less than the lowest expenditure level of the three largest IOUs on a percent of revenue basis, calculated using the utility's total revenue requirement for the year ended December 31, 1994, and IOU total annual expenditures described above under section 381 (approximately 3 percent).

[104] CPUC Decision D.0312062 directs IOUs recover authorized procurement-related energy efficiency [costs] through its existing non-bypassable Public Purpose Programs Charge (PPPC), which applies to all IOU retail customers. Additionally, CPUC D.03-12-062 directs that incremental procurement

Table C-15 shows projected procurement costs for utility energy efficiency programs for the years 2004 through 2008 ($ millions):

Table C-15 IOU Supply Portfolio of Electric Energy Efficiency Procurement

Utility	2004	2005	2006	2007	2008	Total
PG&E	25	50	50	75	100	300
SCE	60	60	60	60	60	300
SDG&E	25	25	25	25	25	125
Total	**110**	**135**	**135**	**160**	**185**	**725**

Table C-16 shows the effect of combining the procurement budget with the budget for electric energy efficiency programs directed under the Public Goods Charge (PGC) funds for 2004 and 2005 ($ millions). This increases the total electric energy efficiency budget for 2004-2005 by $245 million, bringing the total to more than $760 million.

Table C-16 IOU Combined Electric Energy Efficiency Budgets 2004-2005

	PGC Budget	Procurement Budget	Total Budget
PG&E	258	75	333
SCE	183	120	303
SDG&E	77	50	127
Total	**518**	**245**	**763**

Current Energy Efficiency Program Funding

- $763 million was allocated to 2004-2005 electric energy efficiency programs, an increase of $245 million (43 percent) over statutory levels
- The 2006 – 2008 funding cycle was approved at just under $2 billion, of which approximately $1.5 billion is for electric energy efficiency, with the balance for natural gas.

Current Water Efficiency Program Funding

- In 2002 voters approved Proposition 50, which provides $180 million for water use efficiency programs in the years 2003 – 2007[105]. Proposition 50 annual

energy efficiency costs be subject to recovery though a non-bypassable charge to all customers and orders IOUs to establish the Procurement Energy Efficiency and Balancing Account (PEEBA) to track costs and revenues.

[105] Proposition 50 Chapter 7 provides $180 million for water use efficiency programs per year as follows: Urban water use efficiency $60 million; Agricultural water use efficiency $60 million; Water

funding for water efficiency is estimated at $36 million (actual program funds provided water agencies is reported to be an average of approximately $30 million per year[106]).

- Funding for water efficiency programs also comes from several other sources, including the implementing water agency, the state's General Fund, federal funds, and general obligation bonds. While these sources add to the available funds, the total is significantly less than that committed to energy efficiency programs.
- Funding has fallen below commitments made in 2000 through the CALFED Record of Decisions, Stage 1 2000-2007. By 2003 investments lagged by $235 million[107].

Integrated Resource Planning

Currently, water efficiency programs receive no credit for, and planners do not quantify, the large energy savings associated with water saving measures that are implemented. Additionally, until energy efficiency regulation and policy are changed, energy utilities cannot include or target these significant energy-efficiency gains. Neither water nor energy efficiency program planners address or target these potential efficiency gains, and a significant gap exists in statewide water and energy resource planning.

Water, wastewater, and energy efficiency program planners acknowledge the importance of comprehensive resource management. Water efficiency programs are based on the same cost-benefit methodology as energy efficiency programs and reference the Standard Practice Manual.[108] This common methodology recognizes the importance of clearly understanding the following four cost-effectiveness perspectives:

1. Water, wastewater or energy program participants
2. The water, wastewater or energy utility
3. The water, wastewater or energy supply system
4. Society

---

recycling $60,000. The Bond law was passed in November 2002, and the funding will be allocated through 2007 (five years). Proposition 13 also had funding for water use efficiency but in form of loan. DWR Water Use Efficiency Office is funded partially through the general fund; annual budget less than $1 million. In addition to Statewide funding, local agencies also budget for water use efficiency programs.

[106] See footnote 72, Proceeding Minutes page 23.

[107] Department of Water Resources 2005 Water Plan Update, Volume 2, page 22-2.

[108] "A Guide to Customer Incentives for Water Conservation" Prepared by Barakat and Chamberlain for CUWA, CUWCC, and US EPA, February 1994 (EPA # 230R94001).

However, water, wastewater, and energy efficiency cost-benefit valuation is performed from the utility and, in the best cases, the electric supply system ***or*** the water supply system ***or*** the wastewater collection system perspective (See 2 or 3 above). Ultimately the suboptimal affects of this discrete or isolated water, wastewater, and energy resource management is borne by the consumer who must pay the water, the wastewater, and the energy utility bills.

Under the broader societal perspective, transfer payments between the water utility and participating customers are canceled out; also eliminated are transfer payments among the water utility and other utilities. The costs that are avoided by the electric, gas, water, or wastewater utilities are viewed as societal benefits, and any additional costs that are incurred by these utilities as a result of a water efficiency program are societal costs. Drawing the boundary around the entire water use cycle and including all end users and affected utilities facilitates this societal valuation.

Analysis contained in this appendix has demonstrated that the state's water, wastewater and energy resources are inextricably entwined. Incomplete accounting understates the resource value of water use efficiency. Integrated resource planning of water, wastewater and energy must be performed from *society's* perspective and answer the question, "What mix of water and energy efficiency measures will create the greatest return on the combined ratepayer investment?"

An integrated water-energy societal total resource cost valuation would include the avoided marginal cost of water and wastewater treatment, related environmental externalities, and the associated marginal cost of energy (kWh), capacity (kW), transmission, distribution (including line losses), and environmental externalities. Environmental externalities related to avoiding water and energy use need to be itemized (to remove potential double-counting) and combined to reflect composite environmental impacts.

With a more complete avoided cost-based justification, improved cost-benefit ratios and corollary increased program funding, water-efficiency program market penetration could significantly increase. Integrated water and energy demand-side management would increase both water and energy efficiency program impacts.

Suggested Research Topics

1. Regional Cold Water Energy Intensity (near-term):

    a. Research and develop regional cold water energy intensities. Adopt proxy values and establish linkage to forecasting climate zones. The information being developed by the University of California, Santa Barbara and the Pacific Institute will help develop a proxy that can be relied upon to develop pilot water-energy programs while more detailed studies are being conducted. In particular, while studies of urban water uses indicate that significant energy can be saved by reducing water consumption, the drivers for these opportunities are not well understood. A comprehensive inventory, characterization, and assessment of the primary types of water-related energy consumption by type of water source, system, function, and end use will eventually be needed to develop the detailed methodologies upon which cost-effective programs can be based. Water-related energy consumption can then be mapped from its source through various categories of end use to develop a comprehensive understanding of the points and relative magnitudes of energy consumption along the water supply chain, and the types of systems, processes, equipment, and measures that could reduce water and energy consumption at these points.

b. For existing cold ,water measures develop base case unit energy consumption (UEC), high-efficiency (HE) UEC, Base and HE Peak watt and demand savings, volume sensitive installed measure costs, and expected useful life values.
c. Identify opportunities for participating in demand response programs.
d. Identify and evaluate new cold water measures targeted to create resource value specifically suited to integrated water-energy resource planning not previously addressed under the discrete/isolated water/energy resource management regime.
e. For cold water measures found to be viable under item d., above, develop planning data identified for existing cold water measures.
f. Incorporate research elements (steps a. through d., above) into the Database for Energy Efficiency Resources (DEER) for use by energy efficiency program planners consistent with program planning protocols enunciated in CPUC Rulemaking 01-08-028, Decision 05-04-051.

2. Pilot Projects that Document and Quantify the State’s Primary Water-Energy Interdependencies (longer-term):

    a. Select water utilities that collectively represent most of the primary types of water-energy interdependencies in California to include in the pilot. Several water utilities have already indicated interest in participating in such a pilot. These include the Metropolitan Water District (MWD), Inland Empire Utilities Agency (IEUA), the Los Angeles Department of Water and Power (LADWP), Palo Alto Utilities, and Sonoma County Water Agency.
    b. Conduct pilot projects to document the specific relationships.
    c. Inform and adjust proxy values developed above.

3. Seasonal Demand Shifting

    a. In Southern California, groundwater pumping uses approximately 30 percent of the energy required to import water from Northern

California. Groundwater aquifer source production and recharge requirements are fixed and finite. During periods of seasonal peak energy demand water agencies might rely on groundwater sources and recharge the aquifers using imported water months later in the off-peak season. In this manner ground water storage capacities could be used to encourage large-scale and long-term seasonal peak demand shifting.

b. Identify groundwater aquifers where groundwater pumping and recharge is being performed by water agencies.
c. Identify groundwater aquifers that are not currently being tapped for groundwater pumping.
d. Assess the operational feasibility and associated costs and benefits to encourage the seasonal demand shifting described above (item a.).

4. Conveyance-Related Peak Demand Reduction (State Water Project and other systems)

    a. Water agencies undertake projects to increase pumping and storage capacities based upon the given agency's operational cost-benefit perspective. Assess and report incremental cost-effective measures that can be implemented to increase pumping capacities and storage to reduce peak energy demands that are cost-effective, based upon a more comprehensive societal cost-benefit evaluation.
    b. Evaluate opportunities to reduce peak demand through the coordinated operation of federal and state water projects.

APPENDIX D: EXCERPT FROM CALIFORNIA WATER PLAN UPDATE 2005

VOLUME 1, STRATEGIC PLAN, CHAPTER 2, A FRAMEWORK FOR ACTION

Sustaining Our Water Resources

Fundamental Lessons

The Framework for Action embodies the following fundamental lessons, learned by California's water community through the experience of recent decades.

- The practice of water conservation and recycling in California has grown dramatically and must continue as a fundamental strategy for all regions and individual water users in California. The cumulative effect of each decision to use water more efficiently has an enormous impact on future water supplies and water quality.
- California must protect the quality of its water and use available supplies with great efficiency because water will always be a precious resource.
- Science and technology are providing new insights into threats to our watersheds, including our waterways and groundwater basins. California must use this knowledge to take protective actions and manage water in ways that protect and restore the environment.
- Sustainable development and water use foster a strong economy, protect public health and the environment, and enhance our quality of life. Sustainable development relies on the full consideration of social, economic, and environmental issues in policy- and decision-making. Sustainable water use assures that we develop and manage our water and related resources in a way that meets the needs of the present while protecting our environment and assuring the ability to meet the needs of the future.
- Solutions to California's water management issues are best planned and carried out on a regional basis. Hydrological, demographic, geopolitical, socioeconomic, and other differences among California's regions demand that the mix of water management strategies be suited to meet each region's needs for the long term.
- California needs additional groundwater and surface water storage capacity. Storage gives water managers tremendous flexibility to meet multiple needs and provide vital reserves in drier years.

Foundational Actions

To ensure that our water resource use is sustainable, water management at all levels – State, federal, regional, and local - must achieve these three foundational actions:

1. Use water efficiently.
2. Protect water quality.
3. Support environmental stewardship.

A number of resource management strategies that can be used to accomplish the foundational actions are listed in the following sections and described in more detail in Volume 2 Resource Management Strategies.

Use Water Efficiently

To minimize the impacts of water management on California's natural environment and ensure that our state continues to have the water supplies it needs, Californians must use water efficiently to get maximum utility from existing supplies. Californians are already leaders in water use efficiency measures such as conservation and recycling. Because competition for California's limited water resources is growing, we must continue these efforts and be innovative in our pursuit of efficiency. Water use efficiency will continue to be a primary way that we meet increased demand.
In the future, we must broaden our definition of efficient water use to include other ways of getting the most utility out of our groundwater and surface water resources and water management systems:

- Increase levels of urban and agricultural water use efficiency.
- Increase recycled municipal water and expand its uses.
- Reoperate water facilities to improve their operation and efficiency.
- Facilitate environmentally, economically, and socially sound transfers.
- Reduce and eliminate groundwater overdraft.

As California's population grows from 36.5 million to a projected 48 million in 2030, there is bound to be an effect on California's environment. By wringing every bit of utility from every drop of water, Californians can stretch water supplies and help ensure continued economic and environmental health.

Protect Water Quality

California must also protect and improve water quality to safeguard public and environmental health and secure the state's water supplies for their intended uses. Water supply and water quality are inseparable in water management. While implementing projects to reduce water demand or to augment supply, water managers must employ methods and strategies that protect and improve water quality:

- Protect surface waters and aquifers from contamination.
- Explore new treatment technologies for drinking water and groundwater remediation.

- Match water quality to its intended uses.
- Improve management of urban and agricultural runoff.
- Improve watershed management.

Support Environmental Stewardship

To ensure sustainability, California must also manage water in ways that protect and restore the environment. Water is a vital natural resource for people and the environment, so water management activities must occur in the context of resource management and environmental protection. Water development in California has a rich history of conflict, at times pitting water supply projects against ecosystem protection. Water supplies and the environment must both be considered together. Water managers must support environmental stewardship as part of their management responsibilities. As managers develop and deliver reliable water supplies, environmental stewardship can be incorporated in many ways:

- Integrate ecosystem restoration with water planning and land use planning.
- Restore and maintain the structure and function of aquatic ecosystems.
- Minimize the alteration of ecosystems by water management actions.
- Improve watershed management.
- Protect public trust resources.
- Integrate flood management with water supply management.

Recommendations

California Water Plan Update 2005 provides recommendations for the next 25 years. These recommendations are directed at decision-makers throughout the state (referred to as California), the executive and legislative branches of State government, and DWR and other State agencies. (See Chapter 5 Implementation Plan for details.)

1. California needs to invest in reliable, high quality, sustainable, and affordable water conservation, efficient water management, and development of water supplies to protect public health, and to maintain and improve California's economy, environment, and standard of living.

2. State government must provide incentives and assist regional and local agencies and governments and private utilities to prepare integrated resource and drought contingency plans on a watershed basis; to diversify their regional resource management strategies; and to empower them to implement their plans.

3. State government must lead an effort with local agencies and governments to inventory, evaluate, and propose management strategies to remediate the causes and effects of contaminants on surface and groundwater quality.

4. California needs to rehabilitate and maintain its aging water infrastructure, especially drinking water and sewage treatment facilities, operated by State, federal, and local entities.

5. State government must continue to provide leadership for the CALFED Bay-Delta Program to ensure continued and balanced progress on greater water supply reliability, water quality, ecosystem restoration, and levee system integrity.

6. State government needs to take the lead in water planning and management activities that: (a) regions cannot accomplish on their own, (b) the State can do more efficiently, (c) involve interregional, interstate, or international issues, or (d) have broad public benefits.

7. California needs to define and articulate the respective roles, authorities, and responsibilities of State, federal, and local agencies and governments responsible for water.

8. California needs to develop broad and realistic funding strategies that define the role of public investments for water and other water-related resource needs over the next quarter century.

9. State government should invest in research and development to help local agencies and governments implement promising water technologies more cost effectively.

APPENDIX E: A WATER-ENERGY ROADMAP

Recommendations of the Water-Energy Relationship Working Group

Presently, water and energy utilities seek to separately optimize their respective resource portfolios. Since energy is typically their second largest cost,[109] water utilities already proactively seek opportunities to reduce energy consumption and increase energy production to reduce the net cost of their water supplies. However, the search for opportunities typically does not extend beyond their own systems and facilities. This is more a significant opportunity than a problem.

Stakeholder input for this staff paper indicates that the greatest potential for positively affecting the state's energy circumstance is beyond current best practices. Specifically, the primary opportunity is in the integrated value of water, energy, and externalities - like societal value - embedded in a unit of saved water. The incremental benefit of these integrated values can be realized by arranging the systems and operations of both the state's water and energy utilities around this holistic valuation approach.

For example, the state's single largest consumer of energy, the State Water Project (SWP), already strives to maximize off-peak and minimize on-peak pumping. However, if the goal were instead to minimize total and peak water-related energy consumption throughout the state, what options might be considered that would otherwise remain unconsidered? Below is a sample of the types of opportunities that could be possible if the planning perspective were broadened to include the optimization of water and energy resources statewide.

- <u>Shift water pumping to off- and partial-peak time periods</u>. Both DWR and the State Water Contractors (SWC) – 29 water agencies that purchase water from the SWP -- note that the SWP is designed to deliver water 24 hours a day, 365 days a year. Purchasers of SWP water need to take delivery when it comes down the aqueduct. Additional storage at strategic points along the aqueduct, whether owned by SWP or any of its customers, could increase operating flexibility and allow additional shifting of both SWP and SWC pumping loads to partial-and off-peak periods.[110]

- <u>Shift water pumping to non-summer periods</u>. Some water agencies in Southern California already rely heavily on groundwater pumping during the

[109] Salaries are usually first.
[110] Any increase in storage increases operational flexibility. This can be accomplished by oversizing aqueducts and canals, off-stream storage, and pipelines. SWP agricultural customers' systems are presently optimized for 24-hour deliveries. With proper incentives, it may be possible to modify these agricultural customers' systems to increase flexibility in SWP deliveries.

summer, and recharge their wells with imported SWP water during other times of the year. This groundwater production and recharge could be coordinated to create seasonal load-shifting.[111]

- Increase use of recycled water. While use of recycled water has nearly tripled since 1970, it still accounts for a very small percentage of the state's water supplies.[112] At a minimum, recycled water should be used wherever possible for landscape irrigation, though the high cost of dual distribution networks has been a major barrier.[113] When viewed from a societal perspective, significant investment in programs to reduce landscape irrigation is warranted on the basis of their energy benefits alone.

- Capture energy in water systems. Water utilities purchase significant amounts of energy to transport water though their systems. There are opportunities to recapture some of this energy through in-conduit turbines. The effect of this in-conduit hydropower production would be to decrease a water utility's net energy requirements. While opportunities exist to capture this energy, there are few incentives (and many disincentives) for development. Viewed on a holistic basis, the efficient utilization of energy within an existing pipeline or conduit would be viewed as an efficiency retrofit that qualifies for funding support by energy utilities.[114]

- Reduce energy for water pumping. Oversizing and/or lining pipelines can reduce friction and the amount of energy needed to transport water.

- Reduce energy for treatment. Both potable and wastewater systems could be reconfigured to incorporate storage, allowing treatment to be deferred to off-peak periods.

In addition to opportunities for reducing and shifting water utilities' energy consumption, stakeholders identified an important new opportunity – saving energy by saving water. When a unit of water is saved, so too is the energy required to convey, treat, deliver, and safely dispose of that unit of water.

In order to employ this value in designing cost-effective programs, this water ***energy intensity*** must take into account all of the steps in the water cycle. The energy

---

[111] The state's highest electric demand is on hot summer days. If significant water activities could be shifted to other months, the state may need to build less generation and transmission capacity. In addition, electric reliability would be increased, and the adverse public health, safety, and economic impacts of rotating outages avoided.
[112] *California Water Plan Update* 2005, public review draft, April 2005.
[113] During summer months, as much as 50-70 percent of residential water use in Central and Southern California is for landscape irrigation.
[114]In-conduit hydropower does not presently qualify as an energy efficiency retrofit for purposes of energy utilities' programs. While in-conduit hydropower is RPS-eligible and could qualify for supplemental energy payments (SEPs), it would not be feasible to develop mini- and micro-hydro under the same rules as utility-scale generation.

intensity of cold-water energy savings is presently not considered in water or energy efficiency program planning. When a saved unit of water is valued from a societal cost perspective, significant energy-efficiency, embedded in water efficiency, is clear. The following example shows the electric energy resource value of just one water efficiency measure, BMP14[115]:

> An ultra-low-flow toilet saves 11,340 gallons of water per year and has a service life of 25 years. This results in potable cold-water energy savings of 91 kilowatt hours (kWh) per year, or 2,275 kWh over its useful life. The present value of electricity's avoided cost is $141. In 2004, water utility programs installed 1.8 million ultra-low-flow toilets in California residences, resulting in cold water savings of 60 million kWh per year, or 1.5 billion kWh over the program's life. The present avoided cost value through this single BMP is $119 million[116].

This simple analysis shows how energy can be saved by saving water. However, energy utilities are not currently authorized to invest in cold water savings. This raises some important questions:

- How much water or energy could be saved with existing technology, without basing their cost-effectiveness upon a single resource like the avoided cost of water or electricity, natural gas, or diesel?

- What incremental energy benefits would be realized if saved water were valued on a societal basis, and energy utilities were allowed to participate in programs that save energy by saving water?

Regarding a comprehensive statewide water and energy program:

- How can programs and incentives be structured to both encourage collaboration across utility systems and boundaries and allow energy utilities to share the costs of water conservation and efficiency programs (to access water savings not deemed cost-effective on a single utility resource cost test)?

The following table describes some actions that could facilitate a statewide shift toward integrating the water and energy resource planning and management needed to achieve incremental societal benefits.

---

[115] See discussion of water conservation and efficiency "best management practices" (BMPs) in Appendix C.
[116] See Appendix C for full discussion of this issue and information source references.

ENERGY OBJECTIVE	APPROACH	OPTIONS
Optimize the state's water and energy resources & assets on an integrated basis	Build policy framework & infrastructure	1. Identify synergistic benefits that make business sense to both water & energy stakeholders. 2. Revise both water & energy utilities' investment criteria to incorporate a societal perspective. 3. Adjust resource pricing methodologies to reflect total societal values. 4. Authorize energy utilities to invest in programs for cold water savings. 5. Structure funding & incentives to attain targeted responses. 6. Provide low-interest loans & grants for incremental water infrastructure that produce benefits to the electric grid. 7. Create a joint agency task force to establish protocols for sharing costs, benefits and responsibilities among multiple stakeholders subject to different jurisdictional rules and regulations. 8. Coordinate water and energy capital programs to maximize infrastructure investments for benefit of both resources.
Increase energy supplies	Support development of additional hydropower capacity	1. Resolve conflicts with FERC relicensing process. 2. Modify Renewable Portfolio Standards to include all new and increased hydropower capacity. 3. Provide access to Supplemental Energy Payments. 4. Establish incentives for re-powering for incremental pumped storage capacity.[117] 5. Allow in-conduit hydropower to qualify for funding as an energy recovery facility, qualified as an energy efficiency retrofit.
	Remove disincentives to energy self-sufficiency	1. Allow water utilities to wheel self-produced power to themselves, anywhere on their systems. 2. Streamline the interconnection process and reduce costs. 3. Remove net metering caps.
	Encourage production of excess power	1. Provide technical & funding support for development of renewable resources & distributed generation. 2. Encourage partnering between water & energy utilities in power development. 3. Establish long-term power purchase agreement for such excess production that exceeds bulk wholesale markets and

[117] Hetch Hetchy implemented system improvements that increased peak hydropower capacity by 48 MW at a capital cost of $8 million, 83 percent less than the cost of installing a new unit of comparable capacity.

ENERGY OBJECTIVE	APPROACH	OPTIONS
		assures payments that support project financing. 4. Provide a ready market for purchasing any over-production of power (e.g., require investor-owned utilities to include in their energy supply portfolios).
Increase energy efficiency and demand side management	Help water utilities develop & implement comprehensive energy management	Provide technical, funding & other support.
	Reduce peak energy consumption (seasonal & time-of-use)	Increase system & operating flexibility (e.g., increase capacity for pumping groundwater during summer, deferring water imports to fall and winter).
	Establish incentives for shifting seasonal use	Compensate water utilities for deferring water imports from summer to fall.[118]
Increase operating flexibility	Maximize ancillary services benefits of the state's hydropower resources	1. Increase pump storage capacity. 2. Use hydro to shape wind & other intermittent resources (e.g., solar).
	Increase storage	Support development of new and incremental storage wherever possible.[119]
Increase water conservation & efficiency	Increase investments that attain statewide energy benefits	1. Incorporate a societal perspective into water utilities' investment criteria. 2. Allow energy utilities to invest in water system improvements that attain benefits for energy ratepayers. 3 Create a Public Goods Charge equivalent for water utilities.

A Conceptual Road Map

Following is a conceptual road map for a five-year program structured to achieve the above objectives. The plan considers a three-phase approach:

Phase 1 – Policy Framework and Infrastructure
Phase 2 – Pilot Programs
Phase 3 – Implementation

The process of building the policy framework and infrastructure needed to support a major policy shift of this kind would begin in *Phase 1*. *Phase 2* would be triggered by adoption of interim policies and pilot programs by energy utilities, and their regulator(s), in recognition of the energy value of saved water. *Phase 3* would begin with adoption of permanent policies and programs by energy utilities and their regulator(s) that will invest in saving water to save energy.

---

[118] Incentives already exist to encourage shifting loads from on-peak to partial- and off-peak periods.
[119] Water remains the most effective means of storing energy.

The work in each phase is generally described below.

Phase 1 – Policy Framework and Infrastructure [8-12 months]

During the initial phase, three distinct activities would proceed concurrently:

- Task 1: Increase access to existing energy programs and resources by water and wastewater utilities.

- Task 2: Develop a policy roadmap for statewide integrated water and energy planning and management.

- Task 3: Conduct studies of California's water-energy relationships.

Activities included in each task could include, but are not limited to, the following:

Task 1: Increase access by water and wastewater utilities to existing energy programs and resources. Energy utilities already offer programs where water utilities can participate. These include traditional energy efficiency programs such as retrofits of lighting and HVAC and programs for increasing the efficiency of pumps and motors. In addition, the state's investor-owned utilities (IOU) offer energy-performance contracts (EPCs) that provide customized cash incentives for projects that demonstrate real energy savings.

The following tasks are designed to increase access to existing programs and resources, identify additional resources, and facilitate identification of opportunities for attaining incremental benefits through increased collaboration, and, potentially, the joint operation of multi-utilities' systems, resources, and assets.

1.1 Develop a clearinghouse of water-related energy information for water professionals and others concerned about energy and water use in California. The clearinghouse should include the leading references and studies that highlight energy best practices for water utilities; creative approaches to system design and operations that provide operating flexibility to moderate peak energy consumption; opportunities to become energy self-sufficient; and sources of technical, funding and other types of support.

1.2 Develop a pilot assistance program for water utilities to help individual water agencies integrate comprehensive energy planning and management into their activities.

1.2.1 Establish the baseline of current practices. Provide direct and active technical assistance for best practices for reducing energy consumption by water systems and processes. Encode these best practices into benchmarking tools and make them available to practitioners, enabling them to compare their current practices with what is possible. Develop a clearinghouse of information on a range from current to best practices. Establish measurement and evaluation protocols to verify savings and share lessons learned.

1.2.2 Provide incentives for incremental and/or joint infrastructure improvements that reduce total and peak energy requirements for water transport and processing. These incremental facilities would likely include storage (reservoirs, groundwater wells, and oversized pipelines) that both increases system flexibility and facilitates time-of-use (TOU) and/or seasonal load shifting.

1.2.3 Identify long-term funding opportunities for both ongoing existing programs and for funding retrofits that exceed single utility resource cost-effectiveness tests.[120]

1.2.4 Assist in identifying opportunities for peak-load reductions and seasonal load shifting.

1.2.5 Provide technical and funding assistance in identifying and implementing self-generation opportunities, especially renewable resources and emerging technologies.

1.2.6 Facilitate opportunities for collaborating with local energy distribution companies on all aspects of energy management and energy self-sufficiency, including strategies to meet projected load growth.

Depending upon the results of the pilot, successful programs could be quickly ramped up to provide assistance to water agencies statewide.

<u>Task 2: Develop a policy roadmap for statewide integrated water and energy planning and management</u>. A policy shift of this magnitude requires thoughtful consideration of the barriers and hurdles that need to be overcome before successful implementation. A policy roadmap identifying key changes to laws and regulations that would help facilitate the shift would be very beneficial when embarking upon this effort. The types of activities within this task could include:

2.1 <u>Establish a statewide multi-agency Water-Energy Task Force</u>. This task force would provide consistent, long-term leadership, policy direction, and technical and resource support for a comprehensive statewide water-energy program. The Water-Energy Task Force would include staff from the Energy Commission, Department of Water Resources, California Public Utilities Commission, Air Resources Board, State Water Resources Control Board, and the California Department of Health Services.

The goal of the task force would be to achieve the benefits of *statewide integrated planning and management of the state's water and energy resources*. Specific tasks include the following:

[120] Long-term funding was identified as an important factor in gaining support from water utilities.

- Collaboratively build a knowledge base of water and energy interdependencies. Investigate beneficial statewide integrated water and energy planning and management practices and recommend policies, programs, and funding for successful programs.

- Expand the Water-Energy Relationship (WER) Working Group created through this process to include strong participation by all key stakeholder groups needed for successful implementation of the program. The WER Working Group will provide technical advice to the Water-Energy Task Force.

- Designate a Water-Energy Liaison at the Energy Commission. This person or group would be responsible for coordinating policy, research, and programmatic efforts within the Energy Commission and act as liaison to the Water-Energy Task Force, other state agencies, local jurisdictions, and water, wastewater, and energy utilities. Similar people or groups should be identified at other agencies on the Task Force.

- Collaborate with other parties and entities with compatible goals. These include DWR's Office of Water Use Efficiency, the Recycling Task Force, and the Desalination Task Force.

- Develop a roadmap that establishes goals for increasing water efficiency and demand-side management. Among other things, the roadmap should prioritize investments in programs and measures that have the highest resource value and impact. In recognizing that every unit of water saved allows displacement of higher-energy intensity water supplies, high priority should be assigned to reductions in agricultural water use and urban landscape irrigation, both residential and commercial.

- Charge the Water-Energy Task Force with monitoring technology changes that affect the energy intensity of the water cycle, and identify potentially feasible and cost-effective applications.[121] A mechanism should be established to continually identify and incorporate new technologies wherever beneficial and feasible.

2.2 *Build the policy framework and infrastructure.* The concept that there are statewide benefits from "saving water to save energy" needs to be emphasized and regularly underscored. *Energy Report* findings and recommendations should be presented to the CPUC, water and energy utilities, key water and energy

[121] For example, new tunneling equipment and techniques may one day make it possible to drill through mountains instead of transporting water over mountains, significantly reducing energy used for water pumping. In addition, improvements in desalination and other water supply development techniques may become more cost-effective than transporting water from Northern California to Southern California. Further, technologies such as cloud seeding may become more successful in producing local supplies that could reduce Southern California's need for water imports.

policymakers, and other key stakeholders. The bases for computing potential benefits needs to be widely and clearly understood.

Policies, procedures, business processes, analytical methods, investment criteria, and decision making tools all need to be adjusted to support a policy and planning shift of this magnitude. To support this shift, the importance of the state's water-energy relationship needs to be better understood. Preliminary studies show the complexities of the water supply balance and cycle, and geographic, source, end user and other diversities – all of which must be documented, quantified, and modeled to assure that programs and strategies achieve their intended results. Thereafter, policies, rules, regulations, protocols, methodologies, programs, and funding need to be brought into alignment.

- Establish a valuation methodology for the societal value of water. We are just beginning to understand the water-energy relationship. Preliminary studies of the water supply-use-disposal cycle and overall water supply balance show distinctly different energy intensities of water in various regions of the state, depending upon climate, topography, and water storage/recovery/delivery options and methods. In addition, different uses have different energy intensities. A valuation methodology is needed to capture these diversities in a manner that will help planners prioritize their investments.[122]

- Leverage developmental work already in progress by others, including the U.S. Department of Energy National Laboratories' Water-Energy Nexus Program, Pacific Institute, California Urban Water Conservation Council, and the Irrigation Training and Research Center. Collaborate with these (and other) entities, to:

  - Inventory, characterize, and measure California's types of water and energy interdependencies.

  - Develop pilot programs to test tools and methodologies for evaluating tradeoffs among these interdependencies.

  - Develop analytical models for policymakers, regulators, utilities, and other key stakeholders in developing cost effective joint water and energy programs.

- Facilitate joint investment to attain societal benefits. As opportunities are identified that could produce incremental energy benefits but are not deemed

[122] For example, while it may be possible to increase total groundwater capacity in Southern California, unique geological characteristics create uncertainties as to both ultimate capacity (groundwater doesn't behave predictably) and impacts on production capacity of other wells in the vicinity. Similarly, displacing SWP imports with increased seawater desalination in Southern California may not produce a net benefit; nor would over-pumping of groundwater supplies and reducing drought reserves be desirable. All of the interdependencies – water to energy, energy to water, and water to water -- need to be evaluated to determine how best to attain positive net benefits.

cost-effective on a single utility resource cost test, mechanisms are needed that facilitate joint investment to attain those incremental benefits.

- Incorporate a societal valuation approach in both water and energy utilities' resource pricing methodologies, water and energy efficiency program portfolios, and investment criteria.

- To facilitate early results, establish a proxy for the societal value while a detailed methodology is developed.

- Establish a water resource loading order that incorporates the societal value of an avoided unit of water consumption and that mirrors the preferred energy resource loading order in the Joint Agency Energy Action Plan for energy.[123]

- Establish a public goods charge equivalent for public purpose water conservation and efficiency programs.

- Provide incentives for water, wastewater, and energy utilities to optimize their joint resources beyond traditional discrete single utility service boundaries (water or energy).[124]

- Require the state's energy and water planners to collaborate on plans and strategies to reduce net water sector energy consumption and to meet projected energy load growth.

2.3 <u>Identify changes to existing laws and regulations</u>. Examples of some proposed changes are provided in the table of potential actions on pp. 4-5.

2.4 <u>Request that DWR provide input to the IEPR with respect to projected energy load growth in the water sector and potential energy impacts of drought risk mitigation measures</u>. Similarly, request Energy Commission's participation in DWR's Water Plan Update process to provide assumptions as to energy supply availability and price forecasts.[125] Energy Commission and DWR should also synchronize planning assumptions for dry, wet and average hydrology years, as well as

[123] The California Water Plan Update 2005 already identifies a prioritized resource strategy. In order to attain results that optimize the state's water and energy resources on a joint basis, societal values should also be considered in the resource loading order. For example, least-cost water supply options at low electricity prices (e.g., desalination and water transfers) may become expensive when electricity prices are high. Since high electricity prices typically coincide with electricity supply shortages, water resource planning that does not consider energy impacts during times of shortage can create electric reliability risks that affect all California ratepayers. Integrated planning of water and energy resources provides the policy perspective needed to develop contingency plans and strategies for mitigating these types of risks.
[124] For example, the SWP could work with the water agencies that take water from the aqueduct to identify incremental infrastructure and changes to operations that can shift more water pumping to off-peak periods and/or non-summer months.
[125] This could result in a water supply equivalent of the state Energy Action Plan's resource load order.

assumptions as to the duration and magnitude of a multi-year drought for contingency planning purposes.

2.5 Expand the 14 water conservation best management practices (BMPs) to include new measures that meet the broader goals of statewide integrated water and energy planning and management.[126] Prioritize investments in BMPs in accordance with cost-effectiveness from a societal perspective.

2.6 Resurrect long-term purchase commitments (e.g., "standard offer contracts") that provide a ready market for excess power produced by water agencies after meeting all of their own energy requirements. One option might be to merely include such default purchase mechanisms in investor-owned utilities' procurement baselines.

2.7 Increase collaboration among state agencies to assure a consistent policy perspective. Unintended consequences result when multiple regulators seek to discharge their separate responsibilities in absence of a consistent policy framework. For example, while the state is encouraging increased energy production, the Department of Fish and Game restricted operational flows at Silverwood, a man-made reservoir, to protect non-native fish. The WER Working Group identified a need for consistent policy in which state agencies collaborate regularly to assure that energy, water and environmental benefits are continually balanced.

Task 3: Conduct studies of California's water-energy relationships. There is a near-term opportunity to access California ratepayer funds to support the policy shift to statewide integrated water and energy planning and management. Specifically, the state's investor-owned utilities are challenged to attain the targeted energy efficiency goals established by the CPUC for the 2006-2008 round of ratepayer investments. The opportunity to save water to save energy has significant promise to deliver, and potentially to exceed, system benefits targeted by the CPUC. In fact, water-energy programs may well represent the most promising opportunity for "second generation" energy efficiency measures.

The purpose of this task is to establish the foundation for an interim water-energy program that will demonstrate the expected benefits of statewide integrated water and energy resource management, prior to establishing permanent programs. The following work will need to be accomplished to support design of one or more interim programs.

3.1 Establish an interim methodology and proxy for the societal value of a unit of water saved. Design of cost effective programs requires computation of the societal value of a saved unit of water. The computation needs to be performed over the

[126] See Appendix C for a discussion about water conservation BMPs.

entire water use cycle (i.e., the total costs of water, externalities and energy incurred during the entire life of a unit of water[127]).

Ultimately, a comprehensive methodology is needed that recognizes the diversity of water supplies, treatment processes, types of end use, and other factors. The number and complexity of variables will need to be analyzed to determine which are most significant in computing the societal value. In the meantime, a proxy can be employed to allow interim water-energy programs to go forward while detailed studies of the water-energy relationship continue in parallel. There is precedent at the CPUC for utilizing proxies while formal methodologies are being debated and refined.[128]

[Note: The "triple bottom line" concept captures the full spectrum of economic and societal values that today's organizations must address. In developing the proxy, it may be desirable to consider aligning the components of the societal value of water with this evolving concept that is gaining increased acceptance.]

3.2 Inventory needs. Prior to designing the studies, a needs assessment should be conducted to inventory the spectrum of primary water-energy relationships in California, and the current body of data, models, tools, policies, programs, practices, funding, legislation and regulations. Water-related energy consumption will be benchmarked by type of water system, function, and end use. Water-related energy consumption will then be mapped from source through various categories of end use to develop a comprehensive understanding of the points and relative magnitudes of energy consumption along the supply chain, and the types of systems, processes, equipment and measures that could reduce energy consumption at these points.

3.3 Conduct detailed studies. The final task under Phase 1 is to conduct detailed studies of California's water-energy interdependencies and to integrate these data into analytical models and tools that can help both water and energy utilities develop cost-effective joint water-energy programs. The scope of these studies will include establishing baseline water use by all sectors and then linking this to the energy baseline. In addition, technologies will be researched for their water and energy savings potential, and the associated environmental benefits.

Studies will proceed in parallel with commencement of Phase 2 – Pilot Programs. The Pilot Programs will employ a proxy until more detailed data and methods become available to support adoption of a formal methodology for valuing the energy and societal value of an avoided unit of water. The types of studies needed are described more fully at the end of this appendix.

---

[127] Water collection, transmission, treatment, distribution, wastewater treatment, and ultimate disposal or recycling.

[128] In recent years, for example, proxies were established and relied upon by the CPUC for both the market price referent and avoided costs of energy.

Phase 2 – Pilot Programs [12-24 months]
During Phase 2, a proxy will be adopted and applied to develop pilot water-energy programs in which the projected incremental benefits of joint water and energy planning and management can be verified. Concurrently, Phase 1 studies to perfect the data, methods, and tools needed to establish a reliable methodology for supporting development of cost effective programs on an ongoing basis will continue in parallel.

Several water-energy pilot programs are recommended:

- A pilot for investor-owned and municipal utilities that targets specific types of water use reduction to demonstrate and measure the expected economic and reliability benefits to energy ratepayers and the California electric grid. The pilot would employ a proxy for the societal value of each type of water use reduction based on a preliminary methodology, pending completion of further studies and analyses. The scope of such a pilot could include:

    - ➢ Direct co-investment by energy utilities in water conservation and efficiency programs with high potential for energy savings. (The Pacific Institute, in its November 2003 study "Waste Not, Want Not: The Potential for Urban Water Conservation in California", estimated a remaining annual potential for cost effective urban water conservation as high as 2 million acre feet (651.7 billion gallons). Assuming a conservative estimate of 5,000 kWhrs/mg[129], this quantity of saved water could reduce energy consumption by 3,258 Gwh per year. This is about 1.8% of the state's total energy consumption.)

[129] Refer Appendix C, Energy Impact Analysis of Existing Water Management Practices. For the sole purpose of illustrating the potential magnitude of impacts, we have assumed a statewide average value of 5,000 kWhrs/mg.

California Urban Water Use in 2000
and the Potential to Improve Efficiency and Conservation

California Urban Water Use by Sector	Current (2000) Water Use (AF/year)	Best Estimate of Conservation (AF/year)	Potential to Reduce Use (%)	Minimum Cost-Effective Conservation (AF/year)
Residential Indoor	2,300,000	893,000	39	893,000
Residential Outdoor	983,000 to 1,900,000 (b)	360,000 to 580,000 (c)	25 to 40	470,000
Commercial/ Institutional	1,850,000	714,000	39	Combined CII: 658,000
Industrial	665,000	260,000	39	(e)
Unaccounted-for Water	695,000	(d)	(d)	(d)
Total	**6,960,000** (+/- 10%)	2,337,000	34	2,020,000

Source: "Waste Not, Want Not: The Potential for Urban Water Conservation in California", The Pacific Institute, November 2003.

- Subsidized investments in incremental water infrastructure that are expected to attain significant energy benefits (e.g., increasing capacity of, or adding new reservoirs, pipelines, and groundwater wells).

- A pilot that investigates the potential incremental benefits attainable by optimizing joint water and energy resource management of the state's largest water utilities on a combined basis. For example, the pilot could investigate incremental water and/or energy infrastructure (water storage, delivery, power production, etc.) that could increase the operating flexibility of combined large water systems (SWP, SWC, CVP and/or the Colorado River System, as well as other large water systems that are now or could become interconnected).

Phase 3 – Implementation
Phase 3 will be defined by completion of most of the detailed studies of the state's water-energy interdependencies, and of the analytical models and tools that employ these data to design cost effective joint water-energy efficiency programs. During Phase 3, proxies for the societal value of saved water will be replaced with permanent methodologies, and long-lived (5-10 years) water-energy programs will be established and funded.

Implementation Challenges

While some opportunities could be accessed now for early results, there are some challenges to implementation of joint investments that attain the incremental energy resource and reliability benefits of fully integrated water and energy resource planning and management.

1. Water and energy utilities are regulated, operated and managed separately. Short of a few programs in which end users can earn energy incentives for reducing consumption of hot water, there presently is little incentive for water, wastewater, and energy utilities to even coordinate their resource planning activities and much less to share investments in programs and infrastructure.

2. Program goals and incentives will need to be aligned. Societal values are derived from reducing or avoiding the buildup of costs along the water cycle. In this case, water and wastewater utilities and their ratepayers will need to make the investments that attain energy resource and reliability values that benefit other ratepayers and the state overall. This presents challenges with respect to equitable sharing of joint program costs. For example:

   - Increasing use of recycled water in Southern California to reduce high-energy water imports from Northern California may well provide a benefit to all water and energy ratepayers.[130] However, the incremental investment in recycled water distribution facilities needs to be made by a local government or wastewater utility that must then seek recovery of its investment. If the costs of such incremental facilities are allocated only to users of that recycled water, the cost of recycled water may far exceed the cost of potable water.

   - During summer months, as much as 50 to 70 percent of residential water use in central and Southern California is for landscape irrigation. When viewed from a societal perspective, significant investments in programs to reduce landscape irrigation are warranted on the basis of the energy benefits alone. However, water utilities' investments are limited to those that benefit their own ratepayers (i.e., not on the basis of benefits that may accrue to the entire water supply chain or to other stakeholders). Further, there presently is no mechanism that allows energy utilities to invest in programs that reduce water use to save energy.

Allocating incentives to the stakeholder(s) who need to make the investment on behalf of all California ratepayers, both water and energy, is not a trivial task.

---

[130]Water ratepayers benefit by avoiding investments in higher cost water supplies and increasing water supply reliability. Energy ratepayers benefit from associated reductions in energy procurement, as well as by avoiding investments in additional electric infrastructure and by increased electric system reliability.

Additional Needs for Research and Assistance

Integrating water and energy resource management will require additional knowledge in a number of key areas to develop the analytical methods, tools, and data needed to develop and implement cost effective water-energy projects and programs.

Building on Present Knowledge

Considerable work is already being performed in this area. Some current efforts are described in Appendix A.

Additional information is needed to facilitate a statewide policy shift to comprehensive planning and management of the state's water and energy resources. In particular, more accurate information about the nature and magnitude of the state's water and energy relationships -- including the spectrum of opportunities for realizing the synergies of integrated water and energy resource management, the amount of needed investments, and the relative costs vs. benefits of each type of measure – is needed to prioritize investments and develop methods, models, and tools that support cost-effective program design.

The following ***conceptual*** research and development plan describes the primary research activities needed to support the program objectives identified in the table in the first section of this appendix. The plan is structured to allow near- and long-term initiatives to proceed in parallel to provide opportunities for early benefits.

CONCEPTUAL Research and Development Plan

R+D Program Objectives	Near-Term Strategies	Long-Term Strategies
1. Proactively manage water-related energy consumption	Synchronize the state's water & energy planning assumptions and strategies to meet projected energy load growth	Develop comprehensive programs for technical & resource assistance that attain water utilities' energy management best practices
2. Increase understanding of the state's water-energy relationship	Demonstrate primary water-energy interdependencies; develop prototypical values by Forecasting Climate Zones	Inventory, document & quantify the state's primary water-energy interdependencies for input to detailed models & tools
3. Implement statewide integrated water and energy resource management	Develop proxy for interim societal valuation methodology for cold water savings for discussion with CPUC[131], policymakers, other interested stakeholders	Develop data, analytical tools and methodology for computing the societal value of saved water for different water sources, end uses, climate zones, etc. for valuation of societal costs in long-term cold water savings programs
4. Increase water utilities' energy self-sufficiency	Investigate potential for revising existing programs, policies, methods & practices to reduce water utilities' net energy consumption ('net' of power production)	Develop studies, methods, tools & techniques to assist water utilities in becoming energy self-sufficient, and potentially becoming net exporters of power
5. Increase water efficiency and demand-side management	Develop preliminary valuation of existing cold-water efficiency measures	Identify & evaluate new cold-water measures; develop cost-effective programs

Primary research and assistance needs identified to-date are described in more detail below by program objective.

.

Objective 1: Proactively manage water-related energy consumption.

1. Establish baseline of current practices. Research "best practices" for reducing energy consumption by water systems and processes. Encode "best practices" into benchmarking tools and make them available to practitioners, enabling them to compare their current practices to what is possible. Populate the "Clearinghouse" with information on the range from current to best practices. Establish measurement and evaluation protocols to verify savings and provide lessons learned.

2. Conduct an assessment of the penetration and adoption of "best energy practices" by water and wastewater utilities, and barriers and hurdles that prevent or restrict adoption, to support development of targeted assistance programs that incorporate workarounds to identified barriers and hurdles.

3. Track and evaluate energy use by function to enable development of targeted measures and retrofits with high benefit potential. For example, a better

[131] CPUC could adopt a proxy for the societal value of cold water savings that would allow pilot programs to go forward in the 2006-2008 energy efficiency funding cycle.

understanding is needed as to how recycled water fits into the water supply portfolio and water balance. While increasingly stringent federal discharge rules are pressing water utilities to upgrade secondary treatment to higher energy intensive tertiary treatment, incremental energy consumption attributable to the higher level of treatment should be offset (at least in part) by using recycled water to displace higher energy intensity water supplies.

4. Continue to monitor and plan for projected changes in energy usage by water systems and treatment processes. Continue to study the projected energy requirements of changed federal water treatment and discharge regulations as these evolve, and develop approaches to help energy and water utilities manage the energy impacts of these changes.

5. Continue to identify and evaluate opportunities to reduce energy consumption in targeted high-use sectors, such as agriculture. Work with interested stakeholders to identify and evaluate opportunities to reduce energy use by the agricultural sector and to conduct various studies. Potential projects might, for example, include tracking energy-use trends associated with changes in crop-planting and harvesting patterns; evaluating impacts of pressurized irrigation systems (drip and spray) on fields now irrigated by gravity; and converting diesel-engine pumps to motor-driven pumps.

6. Evaluate the potential energy impacts of increased water transfer transactions. Little is known about whether changes in conveyance patterns will have a noticeable impact on water-related energy consumption. The Energy Commission could work with water utilities involved in contracting for or providing conveyance services, to first determine the likely extent of such transactions, and make a rough estimate of the magnitude of change in electricity use patterns. If warranted, staff could recommend further study of methods to track such transactions, and determine and prepare for their expected energy impact.

7. Continue studies with AwwaRF and others to reduce energy consumption by desalination technologies, and to coordinate water and energy planning for dry years. Though the WER Staff Paper identified only fairly modest impacts on the electric system from known planned desalination plant development, the number of planned facilities could increase quickly if one or both of two things occur: an extended drought or other scenario that significantly curtails surface water deliveries, and/or a significant decrease in the cost of operating such facilities.

8. Develop a comprehensive program to study groundwater-related energy use. Groundwater is a particularly significant area of study, since use of groundwater storage has potentially significant impacts, both positive and negative, on water-related energy consumption. On one hand, increased groundwater storage provides significant operating flexibility that could allow

more SWP water deliveries to be shifted from summer to fall. On the other hand, over-pumping groundwater basins could increase energy consumption at undesirable times and also reduce critical drought supplies.

Less is known about groundwater than any other water source. This is due to the fact that each groundwater basin is unique, and production characteristics of wells are often interlinked. Further, since use of groundwater is largely unregulated, the actual quantity of energy used for groundwater pumping statewide is undeterminable. The complexities of groundwater warrants a comprehensive monitoring approach that tracks groundwater levels, pump production, electricity use, and other data over multiple years.[132]

9. Assist water utilities in developing less energy intensive water supplies. For example, increased reliance on recycled water to displace need for desalted water.

10. Continue to build on PIER/AwwaRF's Water and Wastewater Technology Roadmap.

Objective 2: Increase understanding of the state's water-energy relationship.

1. Conduct pilots and studies that document and quantify the state's primary water-energy interdependencies. The information being developed by UCSB and Pacific Institute will help develop a proxy that can be relied upon to develop pilot water-energy programs while more detailed studies are being conducted. In particular, while studies of urban water uses indicate significant energy can be saved by reducing water consumption, the drivers for such opportunities are not well understood. A comprehensive inventory, characterization, and assessment of the primary types of water-related energy consumption by type of water

[132] The Irrigation Training and Research Center (ITRC) study on agricultural energy requirements perhaps goes farther than any other, and bases much of its information on real-world geographical information system (GIS) data; but it must make many assumptions concerning average pump lift (groundwater levels), distribution uniformity, surface water availability (timing factor), irrigation type, average drawdown, discharge pressure, and so forth. It uses the real-world results of the pump efficiency tests conducted for the Agricultural Peak Load Reduction Program by the Center for Irrigation Technology, but those data did not include static or pumping water levels and primarily covered only wells in PG&E's territory.

Considerable additional study is needed in order to facilitate detailed modeling of groundwater supplies. The ITRC study also is the result of at least two levels of computer modeling: that by Department of Water Resources to estimate groundwater levels in Northern California and ITRC's own crop water model, which produced the energy use estimates in its groundbreaking study. Much of ITRC's results are based on what can only be described as rough calculated estimates by DWR for Central and Southern California groundwater volumes, which is especially critical in the Kings and Kern River Basins, where more than 50 percent of the energy used for agriculture-related groundwater pumping occurs. (A detailed discussion of ITRC's model can be found in their report No. 02-001, available on their Web site at www.itrc.org) source, system, function, and end use will eventually be needed to develop the detailed methodologies on which cost-effective programs can be based.

Water-related energy consumption can then be mapped from the source through various categories of end use to develop a comprehensive understanding of the points and relative magnitudes of energy consumption along the water supply chain, and the types of systems, processes, equipment, and measures that could reduce water and energy consumption at these points. Ideally, a sampling of water utilities that collectively represent most of the primary types of water-energy interdependencies in California would be included in such a pilot. Several water utilities have already indicated interest in participating in such a pilot. These include MWD, IEUA, LADWP, Palo Alto Utilities, Sonoma County Water Agency, and Semitropic Water District.

2. <u>Construct a valuation methodology that accounts for the societal cost (water, energy and externalities) of avoided water consumption for various types of water sources and end uses</u>. Relying upon the data and knowledge gained from detailed studies, quantify the water-energy tradeoffs of various resource decisions through computation of the "Regional Cold-Water Energy Intensity".

    - Research and develop regional cold-water energy intensities (or co-opt existing research), adopt prototypical values, and establish linkage to Forecasting Climate Zones;

    - For existing "cold-water measures" develop base case Unit Energy Consumption (UEC), High-Efficiency (HE) UEC, Base and HE Peak watt and demand savings, volume-sensitive installed measure costs and expected useful life values;

    - Identify and evaluate new cold-water measures targeted to create resource value specifically suited to integrated water/energy resource planning not previously addressed under the discrete/isolated water/energy resource management regime;

    - For new cold-water measures deemed viable, develop planning data identified for existing cold-water measures, and;

    - Incorporate research elements into the Database for Energy Efficiency Resources (DEER) for use by energy-efficiency program planners consistent with program planning protocols enunciated in CPUC Rulemaking 01-08-028, Decision 05-04-051.

The above described methodology is consistent with that employed by the CPUC in its regulation of investor-owned utilities' energy efficiency programs, thus allowing proposed investments in water saving measures to be considered on an equivalent basis.

Objective 3: Implement statewide integrated water and energy resource management.

1. Develop tools and techniques for identifying potential infrastructure upgrades that extend beyond a single utility's service boundaries. The goal of implementing statewide integrated water and energy resource planning and management opens up new opportunities that heretofore have not been considered. Specifically, water and energy utilities presently attempt to optimize their separate resources and systems. Many of these utilities have calibrated their models and tools to simulate their own systems' operations. New analytical models, tools, and methods will be needed to help water and energy utilities look beyond their system boundaries, looking for opportunities to optimize their systems and resources on a joint basis with other water and energy utilities with which they may now be interconnected (or potentially could be interconnected). The underlying premise of joint optimization is that it is at this level of fully integrated planning – i.e., the "nexus" – that the most beneficial incremental benefits will be found.

   Potential opportunities include optimizing the systems and operations of the SWP and the 29 member agencies that comprise its sole customer, the SWC, as well as the CVP, the Colorado River system, and any other points of interconnection along the way.

2. Develop analytical models and tools that:

   - Assist both water and energy utilities in developing joint programs that are cost-effective from a societal point of view;

   - Assist wholesale water utilities in evaluating the net benefits of system reconfigurations or retrofits that exceed their own boundaries[133];

   - Assist both water and energy utilities in assessing the net water supply and associated energy and externalities benefits of proposed measures and retrofits (e.g., assessing the net impact on the water supply balance);l

   - Other analytical models and tools needed to support development and implementation of cost-effective joint water-energy programs.

[133] These may include those that assist the State Water Project operator in making determinations as to how to optimize energy consumption for itself and its customer, the SWC, (and potentially other interconnected systems such as CVP and the Colorado River system) on a combined basis.

Objective 4: Increase water utilities' energy self-sufficiency.

Reduce Energy Consumption:

1. Identify opportunities to reduce conveyance-related peak demand reduction (State Water Project and other large water systems). The State Water Contractors and DWR observed that it might be possible to increase off-peak pumping at Edmonston Pumping Station; however, additional pumping capacity would be needed. In addition, they noted that while there may be opportunities to further increase operational flexibility, additional storage would be needed at points along the aqueduct.[134] In order to assess the statewide opportunity to support such incremental capital expenditures that may be beneficial to the state overall, but are not deemed cost-effective from the perspective of a single entity, the Energy Commission could:

    - Assess and report incremental cost-effective measures that can be implemented to increase pumping capacities and storage to reduce peak energy demands that are cost effective based upon a more comprehensive societal cost-benefit evaluation.

    - Evaluate opportunities to reduce peak demands through coordinated operation of federal and state water projects.

2. Assist water utilities in identifying methods to increase operational flexibility such that energy intensive pumping and water treatment processes could be shifted from on-peak periods, to partial- and off-peak periods.

    - According to ACWA, installation of sensors and other equipment could substantially increase water utilities' flexibility in operating their systems. This flexibility could allow water utilities to maintain minimal pumping loads during peak periods, either by delaying such use into the evening hours or at least by cycling such loads sequentially to minimize peak use.

[134] Reservoirs, depending on location and size, including intake and discharge capacities, provide opportunities for pumping load and generation time-shifting -- hourly/daily shifts for small reservoirs, and sometimes monthly/seasonal shifts for larger reservoirs. For large river reservoirs, like Lake Mead, a downstream re-regulation reservoir such as Lake Mojave could support optimum water deliveries and peak generation. However, Lakes Mead and Mojave increase evaporative losses and incur greater costs and environmental concerns.

Urban hillside tank storage reservoirs that provide system pressure for urban retail water users can be oversized to emphasize off-peak pumping to fill the reservoirs if the pumping capacity in the supply system (say, groundwater wells) is simultaneously increased to produce needed water yield in the less-than-24-hours window. (Note: the pumps can wear out sooner and incur increased operations and maintenance costs if the frequency stop/starts increase to match daily Flex-Your-Power objectives.)

- IEUA has designed its systems to allow water to be "detained" during critical peak periods and held for processing during partial- and off-peak periods.

3. Explore increased use of groundwater storage to allow shifting of summer SWP deliveries to fall. In Southern California, groundwater pumping uses approximately 30 percent of the energy required to import water from Northern California. Groundwater aquifer source production and recharge requirements are fixed and finite. During periods of seasonal peak energy demand, water agencies might rely on groundwater sources and recharge the aquifers using imported water months later in the off-peak season. As noted previously, some Southern California water utilities already choose to pump groundwater during summer and recharge groundwater wells during fall. In this manner groundwater storage capacities could be employed to affect large-scale and long-term seasonal peak demand shifting.

   The potential of increasing groundwater storage capacity to further defer seasonal deliveries should be studied. These studies are complicated, due to unique hydrogeology of groundwater basins and potential linkages among wells. The scope would include:

   - Identification of groundwater aquifers where groundwater pumping and recharge is being performed by water utilities;

   - Identification of groundwater aquifers that are not currently being tapped for groundwater pumping that could be used to affect the aforementioned, and;

   - Assessment of the operational feasibility and associated costs and benefits of potential incremental seasonal demand shifting.

   Analytical tools and techniques will be needed to help determine the efficacy and relative costs vs. benefits of this approach. The study should include consideration of who should develop, fund, own, and operate such assets, which potentially may be constructed primarily for energy benefits (i.e., the value of shifting summer demand to other months).

Increase Power Production:

1. Conduct studies of potential for incremental power production through in-conduit hydropower, pumped storage, and repowering. In-conduit hydropower is a very attractive option since it produces energy as a by-product of water operations. Pumped storage has unique capabilities to produce power during peak periods. The Hetchy Hetchy example illustrated a potential for increasing the state's hydropower capacity by as much as 10 percent at a fraction of the cost of installing new units and much more quickly.

There are multiple barriers to water utilities' energy self-sufficiency. The statewide potential for increased hydropower and pumped storage capacity should be assessed, and a roadmap developed for attaining this potential that includes potential work-arounds to the policy, regulatory, economic, technical, and other barriers that will need to be overcome.

2. Develop mitigation strategies to reduce lost hydropower capacity during FERC relicensing. As discussed previously, the National Hydropower Association reported that an average of 8 percent of the nation's total hydropower capacity is being lost through relicensing. The Energy Commission could evaluate causes and identify potential mitigation strategies that consider the societal value of associated hydropower capacity.

3. Develop models and tools to evaluate the energy water tradeoff for reservoir storage. Detailed modeling studies of reservoir operations should be performed to evaluate the additional hydropower generated by changing average year reservoir releases. Similarly, conduct studies detailing the decrease in groundwater pump electricity demand associated with a change in average and dry-year reservoir releases.

4. Develop analytical models and tools that assist both water and energy utilities in assessing power production potential by water utilities including, but not limited to:

    - Self-generation utilizing local renewable resources (digester gas[135], agricultural wastes and other biomass, solar,[136] and hydropower).

    - Renewable resource potential for utility scale generation facilities on watershed lands and rights-of-way.[137]

5. Conduct demonstration projects that allow testing of workarounds to barriers and hurdles and verification of net energy and other benefits of water projects that produce energy. In particular, demonstrate means for water utilities to produce energy as a by-product of water delivery and treatment processes (e.g., in-line conduit applications for water and wastewater utilities), and extrapolate statewide potential for these types of opportunities.

---

[135]Biogas potential need not be restricted to that produced by sewage digesters. Studies are underway to test the energy potential of blending sewage sludge with other biosolids, such as dairy animal waste and food refuse. In addition to increasing power production, this process provides an attractive means for disposing of other types of waste products. In addition, some parties are investigating development of a sludge-derived solid fuel that could be burned in power plants.

[136] Solar power is well suited to meeting small pumping loads in water distribution systems.

[137] Water utilities' extensive watershed land holdings could provide good opportunities for utility-scale wind and concentrating solar power development.

6. Conduct a comprehensive resource assessment of the renewable resource potential of watershed lands and rights-of-way and determine the barriers and hurdles that would need to be overcome.

Objective 5: Increase water efficiency and demand-side management.

1. Develop a pilot program that evaluates societal benefits of water conservation and efficiency programs presently deemed non-cost-effective under traditional water utility planning criteria. Potential items include: new balanced irrigation systems, weather based-irrigation systems, drought tolerant plant/low runoff landscape retrofits, synthetic turf retrofits, free water brooms for every school, connectionless water steamers, digital x-ray machines or x-ray water recirculation systems for doctors and hospitals, free cooling tower conductivity controllers for all public schools and buildings (may be commercial uses too), small scale water recycling projects for communities and golf courses, incentives for new home owners to buy water/energy efficient new homes, large-scale irrigation controllers and landscape retrofits for parks and greenbelts, water softeners[138], etc.

2. Expand the 14 BMPs to include other water conservation measures that meet the more comprehensive "societal" resource test. Building on the important work by CUWCC and its members, Pacific Institute, and other key stakeholders, identify and value incremental measures that can help meet the goals for a comprehensive statewide water-energy program. These measures should then be ranked alongside other feasible water and energy efficiency options on the basis of highest benefit:cost ratio, and then incorporated into joint water-energy programs.

3. Continually improve agricultural water use efficiency.
   - Continue to implement the PIER Agricultural Irrigation Technology Roadmap calling for research and development efforts improve irrigation efficiency. Possible studies include:
     - Reduce the total pressure required to operate drip irrigation technologies; this includes the filter system as well as the pipe and micro-sprayer technologies.
     - Advance the use of longer lasting materials for pump components.
     - Work with the SWP, the CVP and the irrigation districts to increase the flexibility of water deliveries to farms.

[138] One California water agency performed an analysis of retrofits of water softeners. The program did not meet the cost-effectiveness threshold on water alone, but the societal benefits are potentially large.

- Learn more about the increasing trend to adopt drip/micro systems, the implications to energy consumption, and the energy management benefits the systems provide.

- Work with irrigation districts to understand the ramifications increased reliance on groundwater.

- Work with the CPUC to ensure appropriate implementation of Critical Peak Pricing and other TOU rates.

- Work with the CPUC, the utilities, the irrigation districts, and the farmers to ensure widespread use of available energy efficiency programs.

4. Reduce outdoor water consumption. In the context of greatest near-term benefit, there is no dispute among stakeholders: The single largest opportunity for saving a lot of water quickly is through reductions of outdoor water use, both in agricultural and landscape irrigation.

   - Pacific Institute stated that more than 75 percent of the state's total water consumption is used by agriculture.

   - IEUA stated that during summer, outdoor water use for landscape irrigation accounts for 50 to 70 percent of all water consumed by the residential sector. Regions along the coast tend to use less; hotter interior uses more. Seasonal factor translates into even bigger impacts. Overall, reducing residential usage from 200 gal per capita daily down to 80 gal per capita daily (SF/LA numbers).

   - MWD stated that the biggest opportunity for outdoor water savings is in landscape replacement with native plants and synthetic turf.

5. Reduce industrial water use. Pacific Institute estimates that as much as 658,000 AF/year could be saved by the commercial and industrial sectors. Opportunities include joint investment in existing water savings programs, as well as potential joint investment in new technologies. MWD, for example, suggests joint investigation of innovative conservation program investments in industrial process water improvements, such as optimal approaches to industrial recirculation. In addition, this program could include investigation of new water efficiency technologies for various types of industrial processes.

6. Explore a "Golden Carrot" equivalent for water conservation programs. Develop joint investment opportunities in use funds to conduct innovative conservation program investigations into new technology and to kick start methods of obtaining water customer responses to these opportunities. One or more cash and other prizes could be awarded through a competitive innovation program that includes, for example, a call for water and energy-efficient home water heating systems and improvements.

Glossary

acre-foot (AF) - a quantity or volume of water covering one acre to a depth of one foot; equal to 43,560 cubic feet or 325,851 gallons.

active storage capacity - the total usable reservoir capacity available for seasonal or cyclic water storage. It is gross reservoir capacity minus inactive storage capacity.

adjudication - the act of judging or deciding by law. In the context of an adjudicated groundwater basin, landowners or other parties have turned to the courts to settle disputes over how much groundwater can be extracted by each party to the decision.

afterbay - a reservoir that regulates fluctuating discharges from a hydroelectric power plant or a pumping plant.

alluvium - a stratified bed of sand, gravel, silt, and clay deposited by flowing water.

aquifer - a geologic formation that stores and transmits water and yields significant quantities of water to wells and springs.

artificial recharge - the addition of water to a groundwater reservoir by human activity, such as putting surface water into dug or constructed spreading basins or injecting water through wells.

average annual runoff - the average value of annual runoff amounts for a specified area calculated for a selected period of record that represents average hydrologic conditions.

brackish water - water containing dissolved minerals in amounts that exceed normally acceptable standards for municipal, domestic, and irrigation uses. Considerably less saline than sea water.

conjunctive use - the coordinated and planned management of both surface and groundwater resources in order to maximize the efficient use of the resource; that is, the planned and managed operation of a groundwater basin and a surface water storage system combined through a coordinated conveyance infrastructure. Water is stored in the groundwater basin for later and planned use by intentionally recharging the basin during years of above-average surface water supply.

contaminant - any substance or property preventing the use or reducing the usability of the water for ordinary purposes such as drinking, preparing food, bathing washing, recreation, and cooling. Any solute or cause of change in physical properties that renders water unfit for a given use. (Generally considered synonymous with pollutant.)

conveyance - provides for the movement of water and includes the use of natural and constructed facilities including open channels, pipelines, diversions, fish screens distribution systems, and pumplifts.

cost-effective - means that the benefit-to-cost ratio of a proposed program or measure exceeds 1.0. As applied to this test, both costs and benefits are measured either over the life of the program or in terms of societal cost. Water and energy utilities currently include only costs and benefits that affect their respective ratepayers in their cost-effectiveness computations. The conclusion of this staff paper is that a cost-effectiveness test should expand to include all economic, environmental, and societal costs and benefits over the entire water use cycle - even those extending beyond the boundaries of a utility's service territory, resources, and assets - in order to identify opportunities to benefit the state as a whole.[139]

desalination - water treatment process for the removal of salt from water for beneficial use. Source water can be brackish (low salinity) or seawater.

drainage basin - the area of land from which water drains into a river; for example, the Sacramento River Basin, in which all land area drains into the Sacramento River. Also called, "catchment area," "watershed," or "river basin."

drip irrigation - a method of microirrigation wherein water is applied to the soil surface as drops or small streams through emitters. Discharge rates are generally less than 8 L/h (2 gal/h) for a single outlet emitters and 12 L/h (3 gal/h) per meter for line-source emitters.

drought - the magnitude and probability of economic, social or environmental consequences that would occur as a result of a sustained drought under a given study plan. Measures the "drought tolerance" of study plans.

energy consumption - the energy consumption required to facilitate water management-related actions such as desalting, pump-storage, groundwater extraction, conveyance, or treatment. This criterion pertains to the economic feasibility of a proposed action in terms of O&M costs.

energy costs - refers to the cost of energy use related to producing, conveying and applying water. It also refers to the cost of energy use for processes and inputs not directly related to water, but which can affect the demand for water (e.g., the cost of nitrogen fertilizer, tractor manufacturing, etc.).

energy production - both instantaneous capacity (megawatt) and energy produced (kilowatt hours).

[139] Eventually, the issue as to who pays for such incremental statewide benefits will also need to be addressed.

energy self-sufficiency – Refers to an entity that self-supplies its own energy requirements. This would typically be done through a combination of energy efficiency and self-provision of power, whether purchased or produced. Current regulatory barriers prevent water and wastewater utilities from becoming energy self-sufficient.[140]

effluent - wastewater or other liquid, partially or completely treated or in its natural state, flowing from a treatment plant.

end use – the use of energy or water for specific activities such as heating, cooling, toilets, or irrigation.

end users – the consumers of energy or water.

estuary - the lower course of a river entering the sea influenced by tidal action where the tide meets the river current.

evapotranspiration (ET) - the quantity of water transpired (given off), retained in plant tissues, and evaporated from plant tissues and surrounding soil surfaces. Quantitatively, it is usually expressed in terms of depth of water per unit area during a specified period of time.

forebay - a reservoir or pond situated at the intake of a pumping plant or power plant to stabilize water levels; also a storage basin for regulating water for percolation into ground water basins.

gigawatt (GW) - one thousand megawatts (1,000 MW) or one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

gigawatt-hour (GWh) - one million kilowatt-hours of electric power. California's electric utilities generated a total of about 250,000 gigawatt-hours in 2001.

gross reservoir capacity - the total storage capacity available in a reservoir for all purposes, from the streambed to the normal maximum operating level. Includes

[140] Barriers to energy self-sufficiency include:
(a) Long lead-time, complicated and costly interconnections;
(b) Prohibitive stand-by charges for grid-connected self-generation facilities:
(c) Net metering caps that discourage self-production of power at any site in an amount greater than 1MW (or the then current cap);
(d) Inability to “wheel” self-produced and/or purchased power to themselves anywhere on their own system (causing excess power to be either “lost” or sold at uneconomic wholesale prices that do not recover costs;
(e) Lack of standardized contracts, rates and terms for purchasing self-produced power that exceeds water and wastewater utilities’ needs at prices that at least recover costs; and
(f) Prohibitive exit fees assessed to entities departing from bundled electric utility service.

dead (or inactive) storage, but excludes surcharge (water temporarily stored above the elevation of the top of the spillway).

groundwater - water that occurs beneath the land surface and completely fills all pore spaces of the alluvium, soil or rock formation in which it is situated. It excludes soil moisture, which refers to water held by capillary action in the upper unsaturated zones of soil or rock.

groundwater basin - a groundwater reservoir, defined by an overlying land surface and the underlying aquifers that contain water stored in the reservoir.

groundwater overdraft - the condition of a groundwater basin in which the amount of water withdrawn by pumping exceeds the amount of water that recharges the basin over a period of years during which water supply conditions approximate average.

groundwater recharge - increases in groundwater storage by natural conditions or by human activity.

groundwater table - the upper surface of the zone of saturation, except where the surface is formed by an impermeable body.

hydraulic barrier - a barrier developed in the estuary by release of fresh water from upstream reservoirs to prevent intrusion of sea water into the body of fresh water.

hydrologic balance - an accounting of all water inflow to, water outflow from, and changes in water storage within a hydrologic unit over a specified period of time.

hydrologic basin - the complete drainage area upstream from a given point on a stream.

hydrologic region - a study area, consisting of one or more planning subareas.

infiltration - the flow of water downward from the land surface into and through the upper soil layers.

irrigation efficiency (IE) - the efficiency of water application and use, calculated by dividing a portion of applied water that is beneficially used by the total applied water, expressed as a percentage The two main beneficial uses are crop water use (evapotranspiration, etc.) and leaching to maintain a salt balance.

kilovolt (kV) - one-thousand volts (1,000). Distribution lines in residential areas usually are 12 kv (12,000 volts).

kilowatt (kW) - one thousand (1,000) watts. A unit of measure of the amount of electricity needed to operate given equipment. On a hot summer afternoon a typical home, with central air conditioning and other equipment in use, might have a demand of 4 kW each hour.

kilowatt-hour (kWh) - the most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt of electricity supplied for one hour. In 1989, a typical California household consumes 534 kWh in an average month.

land subsidence - the lowering of the natural land surface due to groundwater (or oil and gas) extraction.

maximum contaminant level (MCL) - the highest drinking water contaminant concentration allowed under federal and State Safe Drinking Water Act regulations.

megawatt (MW) - one thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough energy to power 1,000 average California homes.

methane (CH4) - the simplest of hydrocarbons and the principal constituent of natural gas. Pure methane has a heating value of 1,1012 Btu per standard cubic foot.

methanol (also known as Methyl Alcohol, Wood Alcohol, CH3OH) - a liquid formed by catalytically combining carbon monoxide (CO) with hydrogen (H2) in a 1:2 ratio, under high temperature and pressure. Commercially it is typically made by steam reforming natural gas. Also formed in the destructive distillation of wood.

microirrigation - the frequent application of small quantities of water as drops, tiny streams, or miniature spray through emitters or applicators placed along a water delivery line. Microirrigation encompasses a number of methods or concepts such as bubbler, drip, trickle, mist, or spray.

minimum pool - the reservoir or lake level at which water can no longer flow into any conveyance system connected to it.

natural recharge - natural replenishment of an aquifer generally from snowmelt and runoff; through seepage from the surface.

percolation - process in which water moves through a porous material, usually surface water migrating through soil toward a groundwater aquifer.

photovoltaic cell - a semiconductor that converts light directly into electricity.

public water system - a system for the provision of water for human consumption through pipes or other constructed conveyances that has 15 or more service connections or regularly serves at least 25 individuals daily at least 60 days out of the year.

recharge - water added to an aquifer or the process of adding water to an aquifer. Groundwater recharge occurs either naturally as the net gain from precipitation or artificially as the result of human influence.

recycled water - the process of treating municipal, industrial, and agricultural wastewater to produce water that can be productively reused.

riparian right - a right to use surface water, such right derived from the fact that the land in question abuts the banks of streams.

runoff - the volume of surface flow from an area.

salinity - generally, the concentration of mineral salts dissolved in water. Salinity may be expressed in terms of a concentration or as electrical conductivity. When describing salinity influenced by seawater, salinity often refers to the concentration of chlorides in the water.

seawater intrusion barrier - a system designed to retard, cease or repel the advancement of seawater intrusion into potable groundwater supplies along coastal portions of California. The system may be a series of specifically placed injection wells where water is injected to form a hydraulic barrier.

single utility resource cost test - refers to resource optimization from the perspective of a single utility - for example, a water utility already seeking optimization of its own water resources. Energy costs embedded in delivered wholesale water are included when considering cost-effectiveness. However, the single utility resource cost test does not evaluate the impact of these water resource decisions on either water or energy utilities, or on statewide water and energy resources and infrastructure. Similarly, neither water nor energy utilities consider the energy intensity embedded in a unit of avoided water over the entire water use cycle.

societal cost or societal value - refers to the total resource cost, including water <u>and</u> energy <u>and</u> externalities, embedded in a unit of water. For purposes of this staff paper, this term is consistent with that used by the California Public Utilities Commission when determining the cost-effectiveness of energy efficiency programs and measures, and by water utilities when determining the cost-effectiveness of their water conservation incentive programs.[141]

[141] The CPUC’s Energy Efficiency Policy Manual, Chapter 4 Cost-Effectiveness Methodology, relies upon a “Total Resource Cost (TRC) test - Societal Version" as "articulated [in] the California Standard Practices Manual: Economic Analysis of Demand-Side Management Programs." The California Standard Practices Manual states that "The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total cost of the program, including both the participant's and the utility's costs." "A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities, excludes tax credit benefits, and uses a different (societal) discount rate." Water conservation incentives are typically valued in accordance with the February 1994 EPA manual, “A Guide to Customer Incentives

surface supply - water supply obtained from streams, lakes, and reservoirs.

surplus water - water that is not being used directly or indirectly to benefit the environmental, agricultural or urban use sectors.

tailwater – the excess water that was applied for agricultural irrigation water. This water is either returned to the environment or reused for irrigation.

transpiration - an essential physiological process in which plant tissues give off water vapor to the atmosphere.

Urban Water Management Planning Act – Sections 10610 through 10657 of the California Water Code. The Act requires urban water suppliers to prepare urban water management plans which describe and evaluate sources of water supplies, efficient uses of water, demand management measures, implementation strategies and schedules, and other relevant information and programs within their water service areas. Urban water suppliers (CWC Section 10617) are either publicly or privately owned and provide water for municipal purposes, either directly or indirectly, to more than 3,000 customers or supply more than 3,000 acre-feet of water annually.

volt - a unit of electromotive force. It is the amount of force required to drive a steady current of one ampere through a resistance of one ohm. Electrical systems of most homes and office have 120 volts.

water balance - an analysis of the total developed/dedicated supplies, uses, and operational characteristics for a region.

water quality - description of the chemical, physical, and biological characteristics of water, usually in regard to its suitability for a particular purpose or use.

watershed - the land area from which water drains into a stream, river, or reservoir.

---

for Water Conservation" which incorporates by reference the societal valuation approach adopted in the California Standard Practice Manual.

A report accepted by Working Group I of the Intergovernmental Panel on Climate Change but not approved in detail

"Acceptance" of IPCC Reports at a Session of the Working Group or Panel signifies that the material has not been subject to line-by-line discussion and agreement, but nevertheless presents a comprehensive, objective and balanced view of the subject matter.

Technical Summary

Coordinating Lead Authors:

Susan Solomon (USA), Dahe Qin (China), Martin Manning (USA, New Zealand)

Lead Authors:

Richard B. Alley (USA), Terje Berntsen (Norway), Nathaniel L. Bindoff (Australia), Zhenlin Chen (China), Amnat Chidthaisong (Thailand), Jonathan M. Gregory (UK), Gabriele C. Hegerl (USA, Germany), Martin Heimann (Germany, Switzerland), Bruce Hewitson (South Africa), Brian J. Hoskins (UK), Fortunat Joos (Switzerland), Jean Jouzel (France), Vladimir Kattsov (Russia), Ulrike Lohmann (Switzerland), Taroh Matsuno (Japan), Mario Molina (USA, Mexico), Neville Nicholls (Australia), Jonathan Overpeck (USA), Graciela Raga (Mexico, Argentina), Venkatachalam Ramaswamy (USA), Jiawen Ren (China), Matilde Rusticucci (Argentina), Richard Somerville (USA), Thomas F. Stocker (Switzerland), Ronald J. Stouffer (USA), Penny Whetton (Australia), Richard A. Wood (UK), David Wratt (New Zealand)

Contributing Authors:

J. Arblaster (USA, Australia), G. Brasseur (USA, Germany), J.H. Christensen (Denmark), K.L. Denman (Canada), D.W. Fahey (USA), P. Forster (UK), J. Haywood (UK), E. Jansen (Norway), P.D. Jones (UK), R. Knutti (Switzerland), H. Le Treut (France), P. Lemke (Germany), G. Meehl (USA), D. Randall (USA), D.A. Stone (UK, Canada), K.E. Trenberth (USA), J. Willebrand (Germany), F. Zwiers (Canada)

Review Editors:

Kansri Boonpragob (Thailand), Filippo Giorgi (Italy), Bubu Pateh Jallow (The Gambia)

This Technical Summary should be cited as:

Solomon, S., D. Qin, M. Manning, R.B. Alley, T. Berntsen, N.L. Bindoff, Z. Chen, A. Chidthaisong, J.M. Gregory, G.C. Hegerl, M. Heimann, B. Hewitson, B.J. Hoskins, F. Joos, J. Jouzel, V. Kattsov, U. Lohmann, T. Matsuno, M. Molina, N. Nicholls, J. Overpeck, G. Raga, V. Ramaswamy, J. Ren, M. Rusticucci, R. Somerville, T.F. Stocker, P. Whetton, R.A. Wood and D. Wratt, 2007: Technical Summary. In: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Table of Contents

TS.1 Introduction

In the six years since the IPCC's Third Assessment Report (TAR), significant progress has been made in understanding past and recent climate change and in projecting future changes. These advances have arisen from large amounts of new data, more sophisticated analyses of data, improvements in the understanding and simulation of physical processes in climate models and more extensive exploration of uncertainty ranges in model results. The increased confidence in climate science provided by these developments is evident in this Working Group I contribution to the IPCC's Fourth Assessment Report.

While this report provides new and important policy-relevant information on the scientific understanding of climate change, the complexity of the climate system and the multiple interactions that determine its behaviour impose limitations on our ability to understand fully the future course of Earth's global climate. There is still an incomplete physical understanding of many components of the climate system and their role in climate change. Key uncertainties include aspects of the roles played by clouds, the cryosphere, the oceans, land use and couplings between climate and biogeochemical cycles. The areas of science covered in this report continue to undergo rapid progress and it should be recognised that the present assessment reflects scientific understanding based on the peer-reviewed literature available in mid-2006.

The key findings of the IPCC Working Group I assessment are presented in the Summary for Policymakers. This Technical Summary provides a more detailed overview of the scientific basis for those findings and provides a road map to the chapters of the underlying report. It focuses on key findings, highlighting what is new since the TAR. The structure of the Technical Summary is as follows:

- Section 2: an overview of current scientific understanding of the natural and anthropogenic drivers of changes in climate;
- Section 3: an overview of observed changes in the climate system (including the atmosphere, oceans and cryosphere) and their relationships to physical processes;
- Section 4: an overview of explanations of observed climate changes based on climate models and physical understanding, the extent to which climate change can be attributed to specific causes and a new evaluation of climate sensitivity to greenhouse gas increases;
- Section 5: an overview of projections for both near- and far-term climate changes including the time scales of responses to changes in forcing, and probabilistic information about future climate change; and
- Section 6: a summary of the most robust findings and the key uncertainties in current understanding of physical climate change science.

Each paragraph in the Technical Summary reporting substantive results is followed by a reference in curly brackets to the corresponding chapter section(s) of the underlying report where the detailed assessment of the scientific literature and additional information can be found.

TS.2 Changes in Human and Natural Drivers of Climate

The Earth's global mean climate is determined by incoming energy from the Sun and by the properties of the Earth and its atmosphere, namely the reflection, absorption and emission of energy within the atmosphere and at the surface. Although changes in received solar energy (e.g., caused by variations in the Earth's orbit around the Sun) inevitably affect the Earth's energy budget, the properties of the atmosphere and surface are also important and these may be affected by climate feedbacks. The importance of climate feedbacks is evident in the nature of past climate changes as recorded in ice cores up to 650,000 years old.

Changes have occurred in several aspects of the atmosphere and surface that alter the global energy budget of the Earth and can therefore cause the climate to change. Among these are increases in greenhouse gas concentrations that act primarily to increase the atmospheric absorption of outgoing radiation, and increases in aerosols (microscopic airborne particles or droplets) that act to reflect and absorb incoming solar radiation and change cloud radiative properties. Such changes cause a radiative forcing of the climate system.[1] Forcing agents can differ considerably from one another in terms of the magnitudes of forcing, as well as spatial and temporal features. Positive and negative radiative forcings contribute to increases and decreases, respectively, in

[1] 'Radiative forcing' is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system and is an index of the importance of the factor as a potential climate change mechanism. Positive forcing tends to warm the surface while negative forcing tends to cool it. In this report, radiative forcing values are for changes relative to a pre-industrial background at 1750, are expressed in Watts per square metre (W m^{-2}) and, unless otherwise noted, refer to a global and annual average value. See Glossary for further details.

Box TS.1: Treatment of Uncertainties in the Working Group I Assessment

The importance of consistent and transparent treatment of uncertainties is clearly recognised by the IPCC in preparing its assessments of climate change. The increasing attention given to formal treatments of uncertainty in previous assessments is addressed in Section 1.6. To promote consistency in the general treatment of uncertainty across all three Working Groups, authors of the Fourth Assessment Report have been asked to follow a brief set of guidance notes on determining and describing uncertainties in the context of an assessment.[2] This box summarises the way that Working Group I has applied those guidelines and covers some aspects of the treatment of uncertainty specific to material assessed here.

Uncertainties can be classified in several different ways according to their origin. Two primary types are 'value uncertainties' and 'structural uncertainties'. Value uncertainties arise from the incomplete determination of particular values or results, for example, when data are inaccurate or not fully representative of the phenomenon of interest. Structural uncertainties arise from an incomplete understanding of the processes that control particular values or results, for example, when the conceptual framework or model used for analysis does not include all the relevant processes or relationships. Value uncertainties are generally estimated using statistical techniques and expressed probabilistically. Structural uncertainties are generally described by giving the authors' collective judgment of their confidence in the correctness of a result. In both cases, estimating uncertainties is intrinsically about describing the limits to knowledge and for this reason involves expert judgment about the state of that knowledge. A different type of uncertainty arises in systems that are either chaotic or not fully deterministic in nature and this also limits our ability to project all aspects of climate change.

The scientific literature assessed here uses a variety of other generic ways of categorising uncertainties. Uncertainties associated with 'random errors' have the characteristic of decreasing as additional measurements are accumulated, whereas those associated with 'systematic errors' do not. In dealing with climate records, considerable attention has been given to the identification of systematic errors or unintended biases arising from data sampling issues and methods of analysing and combining data. Specialised statistical methods based on quantitative analysis have been developed for the detection and attribution of climate change and for producing probabilistic projections of future climate parameters. These are summarised in the relevant chapters.

The uncertainty guidance provided for the Fourth Assessment Report draws, for the first time, a careful distinction between levels of confidence in scientific understanding and the likelihoods of specific results. This allows authors to express high confidence that an event is extremely unlikely (e.g., rolling a dice twice and getting a six both times), as well as high confidence that an event is about as likely as not (e.g., a tossed coin coming up heads). Confidence and likelihood as used here are distinct concepts but are often linked in practice.

The standard terms used to define levels of confidence in this report are as given in the IPCC Uncertainty Guidance Note, namely:

Confidence Terminology	**Degree of confidence in being correct**
Very high confidence	At least 9 out of 10 chance
High confidence	About 8 out of 10 chance
Medium confidence	About 5 out of 10 chance
Low confidence	About 2 out of 10 chance
Very low confidence	Less than 1 out of 10 chance

Note that 'low confidence' and 'very low confidence' are only used for areas of major concern and where a risk-based perspective is justified.

Chapter 2 of this report uses a related term 'level of scientific understanding' when describing uncertainties in different contributions to radiative forcing. This terminology is used for consistency with the Third Assessment Report, and the basis on which the authors have determined particular levels of scientific understanding uses a combination of approaches consistent with the uncertainty guidance note as explained in detail in Section 2.9.2 and Table 2.11.

(continued)

[2] The IPCC Uncertainty Guidance Note is included in Supplementary Material for this report.

The standard terms used in this report to define the likelihood of an outcome or result where this can be estimated probabilistically are:

Likelihood Terminology	Likelihood of the occurrence/ outcome
Virtually certain	> 99% probability
Extremely likely	> 95% probability
Very likely	> 90% probability
Likely	> 66% probability
More likely than not	> 50% probability
About as likely as not	33 to 66% probability
Unlikely	< 33% probability
Very unlikely	< 10% probability
Extremely unlikely	< 5% probability
Exceptionally unlikely	< 1% probability

The terms 'extremely likely', 'extremely unlikely' and 'more likely than not' as defined above have been added to those given in the IPCC Uncertainty Guidance Note in order to provide a more specific assessment of aspects including attribution and radiative forcing.

Unless noted otherwise, values given in this report are assessed best estimates and their uncertainty ranges are 90% confidence intervals (i.e., there is an estimated 5% likelihood of the value being below the lower end of the range or above the upper end of the range). Note that in some cases the nature of the constraints on a value, or other information available, may indicate an asymmetric distribution of the uncertainty range around a best estimate. In such cases, the uncertainty range is given in square brackets following the best estimate.

global average surface temperature. This section updates the understanding of estimated anthropogenic and natural radiative forcings.

The overall response of global climate to radiative forcing is complex due to a number of positive and negative feedbacks that can have a strong influence on the climate system (see e.g., Sections 4.5 and 5.4). Although water vapour is a strong greenhouse gas, its concentration in the atmosphere changes in response to changes in surface climate and this must be treated as a feedback effect and not as a radiative forcing. This section also summarises changes in the surface energy budget and its links to the hydrological cycle. Insights into the effects of agents such as aerosols on precipitation are also noted.

TS.2.1 Greenhouse Gases

The dominant factor in the radiative forcing of climate in the industrial era is the increasing concentration of various greenhouse gases in the atmosphere. Several of the major greenhouse gases occur naturally but increases in their atmospheric concentrations over the last 250 years are due largely to human activities. Other greenhouse gases are entirely the result of human activities. The contribution of each greenhouse gas to radiative forcing over a particular period of time is determined by the change in its concentration in the atmosphere over that period and the effectiveness of the gas in perturbing the radiative balance. Current atmospheric concentrations of the different greenhouse gases considered in this report vary by more than eight orders of magnitude (factor of 10^8), and their radiative efficiencies vary by more than four orders of magnitude (factor of 10^4), reflecting the enormous diversity in their properties and origins.

The current concentration of a greenhouse gas in the atmosphere is the net result of the history of its past emissions and removals from the atmosphere. The gases and aerosols considered here are emitted to the atmosphere by human activities or are formed from precursor species emitted to the atmosphere. These emissions are offset by chemical and physical removal processes. With the important exception of carbon dioxide (CO_2), it is generally the case that these processes remove a specific fraction of the amount of a gas in the atmosphere each year and the inverse of this removal rate gives the mean lifetime for that gas. In some cases, the removal rate may vary with gas concentration or other atmospheric properties (e.g., temperature or background chemical conditions).

Long-lived greenhouse gases (LLGHGs), for example, CO_2, methane (CH_4) and nitrous oxide (N_2O), are chemically stable and persist in the atmosphere over time scales of a decade to centuries or longer, so that their emission has a long-term influence on climate. Because these gases are long lived, they become well mixed throughout the atmosphere much faster than they are removed and their global concentrations can be accurately estimated from data at a few locations. Carbon dioxide does not have a specific lifetime because it is continuously cycled between the atmosphere, oceans and land biosphere and its net removal from the atmosphere involves a range of processes with different time scales.

Short-lived gases (e.g., sulphur dioxide and carbon monoxide) are chemically reactive and generally removed by natural oxidation processes in the atmosphere, by removal at the surface or by washout in precipitation; their concentrations are hence highly variable. Ozone is a significant greenhouse gas that is formed and destroyed by chemical reactions involving other species in the atmosphere. In the troposphere, the human influence on ozone occurs primarily through changes in precursor gases that lead to its formation, whereas in the stratosphere, the human influence has been primarily through changes in ozone removal rates caused by chlorofluorocarbons (CFCs) and other ozone-depleting substances.

TS.2.1.1 Changes in Atmospheric Carbon Dioxide, Methane and Nitrous Oxide

Current concentrations of atmospheric CO_2 and CH_4 far exceed pre-industrial values found in polar ice core records of atmospheric composition dating back 650,000 years. Multiple lines of evidence confirm that the post-industrial rise in these gases does not stem from natural mechanisms (see Figure TS.1 and Figure TS.2). {2.3, 6.3–6.5, FAQ 7.1}

The total radiative forcing of the Earth's climate due to increases in the concentrations of the LLGHGs CO_2, CH_4 and N_2O, and *very likely* the rate of increase in the total forcing due to these gases over the period since 1750, are unprecedented in more than 10,000 years (Figure TS.2). It is *very likely* that the sustained rate of increase in the combined radiative forcing from these greenhouse gases of about +1 W m^{-2} over the past four decades is at least six times faster than at any time during the two millennia before the Industrial Era, the period for which ice core data have the required temporal resolution. The radiative forcing due to these LLGHGs has the highest level of confidence of any forcing agent. {2.3, 6.4}

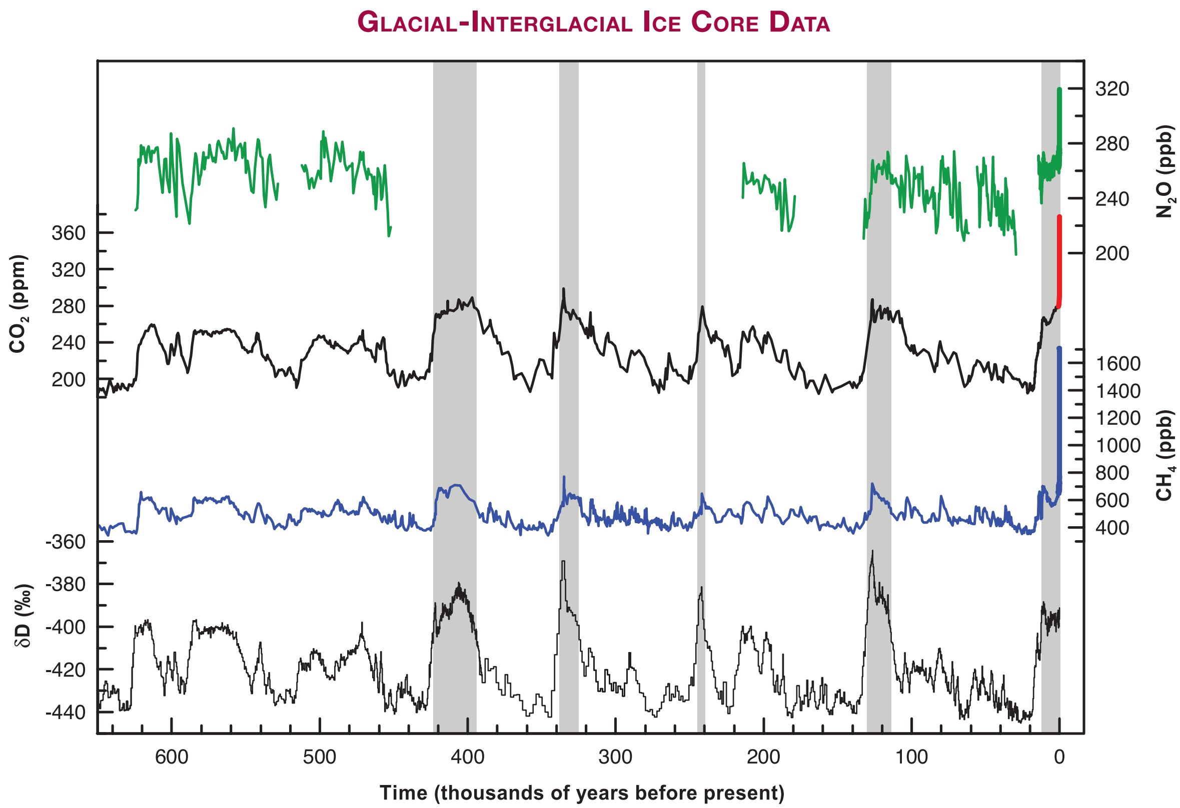


Figure TS.1. *Variations of deuterium (δD) in antarctic ice, which is a proxy for local temperature, and the atmospheric concentrations of the greenhouse gases carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) in air trapped within the ice cores and from recent atmospheric measurements. Data cover 650,000 years and the shaded bands indicate current and previous interglacial warm periods. {Adapted from Figure 6.3}*

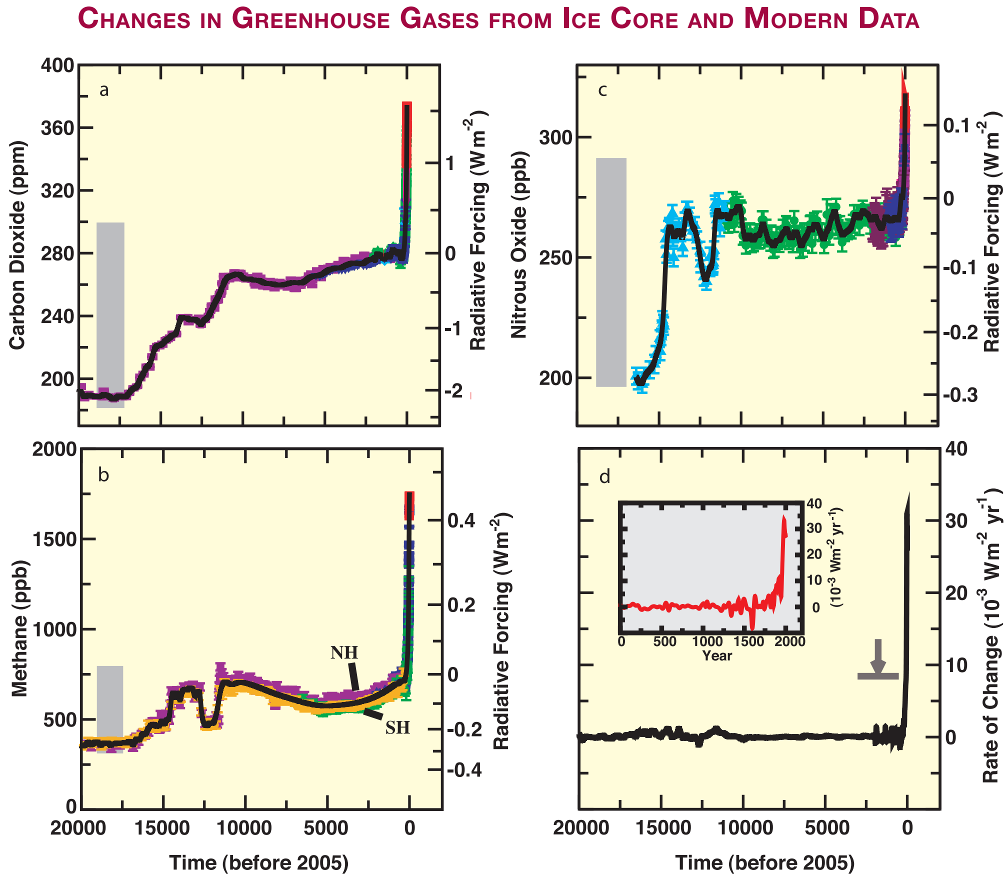


Figure TS.2. *The concentrations and radiative forcing by (a) carbon dioxide (CO_2), (b) methane (CH_4), (c) nitrous oxide (N_2O) and (d) the rate of change in their combined radiative forcing over the last 20,000 years reconstructed from antarctic and Greenland ice and firn data (symbols) and direct atmospheric measurements (panels a,b,c, red lines). The grey bars show the reconstructed ranges of natural variability for the past 650,000 years. The rate of change in radiative forcing (panel d, black line) has been computed from spline fits to the concentration data. The width of the age spread in the ice data varies from about 20 years for sites with a high accumulation of snow such as Law Dome, Antarctica, to about 200 years for low-accumulation sites such as Dome C, Antarctica. The arrow shows the peak in the rate of change in radiative forcing that would result if the anthropogenic signals of CO_2, CH_4, and N_2O had been smoothed corresponding to conditions at the low-accumulation Dome C site. The negative rate of change in forcing around 1600 shown in the higher-resolution inset in panel d results from a CO_2 decrease of about 10 ppm in the Law Dome record. {Figure 6.4}*

The concentration of atmospheric CO_2 has increased from a pre-industrial value of about 280 ppm to 379 ppm in 2005. Atmospheric CO_2 concentration increased by only 20 ppm over the 8000 years prior to industrialisation; multi-decadal to centennial-scale variations were less than 10 ppm and *likely* due mostly to natural processes. However, since 1750, the CO_2 concentration has risen by nearly 100 ppm. The annual CO_2 growth rate was larger during the last 10 years (1995–2005 average: 1.9 ppm yr^{-1}) than it has been since continuous direct atmospheric measurements began (1960–2005 average: 1.4 ppm yr^{-1}). {2.3, 6.4, 6.5}

Increases in atmospheric CO_2 since pre-industrial times are responsible for a radiative forcing of +1.66 ± 0.17 W m^{-2}; a contribution which dominates all other radiative forcing agents considered in this report. For the decade from 1995 to 2005, the growth rate of CO_2 in the atmosphere led to a 20% increase in its radiative forcing. {2.3, 6.4, 6.5}

Emissions of CO_2 from fossil fuel use and from the effects of land use change on plant and soil carbon are the primary sources of increased atmospheric CO_2. Since 1750, it is estimated that about 2/3rds of anthropogenic CO_2 emissions have come from fossil fuel burning and about 1/3rd from land use change. About 45% of this CO_2 has remained in the atmosphere, while about 30% has been taken up by the oceans and the remainder has been taken up by the terrestrial biosphere. About half of a CO_2 pulse to the atmosphere is removed over a time scale of 30 years; a further 30% is removed within a few centuries; and the remaining 20% will typically stay in the atmosphere for many thousands of years. {7.3}

In recent decades, emissions of CO_2 have continued to increase (see Figure TS.3). Global annual fossil

CO_2 emissions[3] increased from an average of 6.4 ± 0.4 GtC yr^{-1} in the 1990s to 7.2 ± 0.3 GtC yr^{-1} in the period 2000 to 2005. Estimated CO_2 emissions associated with land use change, averaged over the 1990s, were[4] 0.5 to 2.7 GtC yr^{-1}, with a central estimate of 1.6 Gt yr^{-1}. Table TS.1 shows the estimated budgets of CO_2 in recent decades. {2.3, 6.4, 7.3, FAQ 7.1}

Since the 1980s, natural processes of CO_2 uptake by the terrestrial biosphere (i.e., the residual land sink in Table TS.1) and by the oceans have removed about 50% of anthropogenic emissions (i.e., fossil CO_2 emissions and land use change flux in Table TS.1). These removal processes are influenced by the atmospheric CO_2 concentration and by changes in climate. Uptake by the oceans and the terrestrial biosphere have been similar in magnitude but the terrestrial biosphere uptake is more variable and was higher in the 1990s than in the 1980s by about 1 GtC yr^{-1}. Observations demonstrate that dissolved CO_2 concentrations in the surface ocean (pCO_2) have been increasing nearly everywhere, roughly following the atmospheric CO_2 increase but with large regional and temporal variability. {5.4, 7.3}

Carbon uptake and storage in the terrestrial biosphere arise from the net difference between uptake due to vegetation growth, changes in reforestation and sequestration, and emissions due to heterotrophic respiration, harvest, deforestation, fire, damage by pollution and other disturbance factors affecting biomass and soils. Increases and decreases in fire frequency in different regions have affected net carbon uptake, and in boreal regions, emissions due to fires appear to have increased over recent decades. Estimates of net CO_2 surface fluxes from inverse studies using networks of atmospheric data demonstrate significant land uptake in the mid-latitudes of the Northern Hemisphere (NH) and near-zero land-atmosphere fluxes in the tropics, implying that tropical deforestation is approximately balanced by regrowth. {7.3}

Short-term (interannual) variations observed in the atmospheric CO_2 growth rate are primarily controlled by changes in the flux of CO_2 between the atmosphere and the terrestrial biosphere, with a smaller but significant fraction due to variability in ocean fluxes (see Figure TS.3). Variability in the terrestrial biosphere flux is driven by climatic fluctuations, which affect the uptake of CO_2 by plant growth and the return of CO_2 to the atmosphere by the decay of organic material through heterotrophic respiration and fires. El Niño-Southern Oscillation (ENSO) events are a major source of interannual variability in atmospheric CO_2 growth rate, due to their effects on fluxes through land and sea surface temperatures, precipitation and the incidence of fires. {7.3}

The direct effects of increasing atmospheric CO_2 on large-scale terrestrial carbon uptake cannot be quantified reliably at present. Plant growth can be stimulated by increased atmospheric CO_2 concentrations and by nutrient deposition (fertilization effects). However, most experiments and studies show that such responses appear to be relatively short lived and strongly coupled

Table TS.1. *Global carbon budget. By convention, positive values are CO_2 fluxes (GtC yr^{-1}) into the atmosphere and negative values represent uptake from the atmosphere (i.e., 'CO_2 sinks'). Fossil CO_2 emissions for 2004 and 2005 are based on interim estimates. Due to the limited number of available studies, for the net land-to-atmosphere flux and its components, uncertainty ranges are given as 65% confidence intervals and do not include interannual variability (see Section 7.3). NA indicates that data are not available.*

	1980s	1990s	2000–2005
Atmospheric increase	3.3 ± 0.1	3.2 ± 0.1	4.1 ± 0.1
Fossil carbon dioxide emissions	5.4 ± 0.3	6.4 ± 0.4	7.2 ± 0.3
Net ocean-to-atmosphere flux	–1.8 ± 0.8	–2.2 ± 0.4	–2.2 ± 0.5
Net land-to-atmosphere flux	–0.3 ± 0.9	–1.0 ± 0.6	–0.9 ± 0.6
Partitioned as follows			
Land use change flux	1.4 (0.4 to 2.3)	1.6 (0.5 to 2.7)	NA
Residual land sink	–1.7 (–3.4 to 0.2)	–2.6 (–4.3 to –0.9)	NA

[3] Fossil CO_2 emissions include those from the production, distribution and consumption of fossil fuels and from cement production. Emission of 1 GtC corresponds to 3.67 $GtCO_2$.

[4] As explained in Section 7.3, uncertainty ranges for land use change emissions, and hence for the full carbon cycle budget, can only be given as 65% confidence intervals.

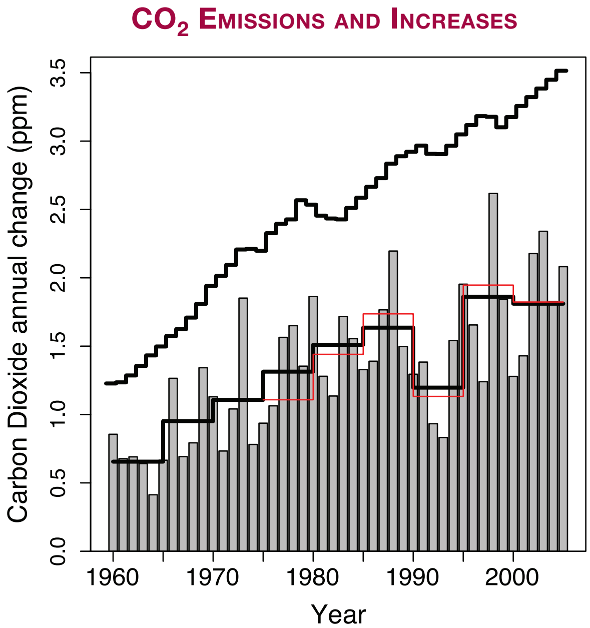


Figure TS.3. *Annual changes in global mean CO_2 concentration (grey bars) and their five-year means from two different measurement networks (red and lower black stepped lines). The five-year means smooth out short-term perturbations associated with strong ENSO events in 1972, 1982, 1987 and 1997. Uncertainties in the five-year means are indicated by the difference between the red and lower black lines and are of order 0.15 ppm. The upper stepped line shows the annual increases that would occur if all fossil fuel emissions stayed in the atmosphere and there were no other emissions. {Figure 7.4}*

to other effects such as availability of water and nutrients. Likewise, experiments and studies of the effects of climate (temperature and moisture) on heterotrophic respiration of litter and soils are equivocal. Note that the effect of climate change on carbon uptake is addressed separately in section TS.5.4. {7.3}

The CH_4 abundance in 2005 of about 1774 ppb is more than double its pre-industrial value. Atmospheric CH_4 concentrations varied slowly between 580 and 730 ppb over the last 10,000 years, but increased by about 1000 ppb in the last two centuries, representing the fastest changes in this gas over at least the last 80,000 years. In the late 1970s and early 1980s, CH_4 growth rates displayed maxima above 1% yr^{-1}, but since the early 1990s have decreased significantly and were close to zero for the six-year period from 1999 to 2005. Increases in CH_4 abundance occur when emissions exceed removals. The recent decline in growth rates implies that emissions now approximately match removals, which are due primarily to oxidation by the hydroxyl radical (OH). Since the TAR, new studies using two independent tracers (methyl chloroform and ^{14}CO) suggest no significant long-term change in the global abundance of OH. Thus, the slowdown in the atmospheric CH_4 growth rate since about 1993 is *likely* due to the atmosphere approaching an equilibrium during a period of near-constant total emissions. {2.3, 7.4, FAQ 7.1}

Increases in atmospheric CH_4 concentrations since pre-industrial times have contributed a radiative forcing of +0.48 ± 0.05 W m^{-2}. Among greenhouse gases, this forcing remains second only to that of CO_2 in magnitude. {2.3}

Current atmospheric CH_4 levels are due to continuing anthropogenic emissions of CH_4, which are greater than natural emissions. Total CH_4 emissions can be well determined from observed concentrations and independent estimates of removal rates. Emissions from individual sources of CH_4 are not as well quantified as the total emissions but are mostly biogenic and include emissions from wetlands, ruminant animals, rice agriculture and biomass burning, with smaller contributions from industrial sources including fossil fuel-related emissions. This knowledge of CH_4 sources, combined with the small natural range of CH_4 concentrations over the past 650,000 years (Figure TS.1) and their dramatic increase since 1750 (Figure TS.2), make it *very likely* that the observed long-term changes in CH_4 are due to anthropogenic activity. {2.3, 6.4, 7.4}

In addition to its slowdown over the last 15 years, the growth rate of atmospheric CH_4 has shown high interannual variability, which is not yet fully explained. The largest contributions to interannual variability during the 1996 to 2001 period appear to be variations in emissions from wetlands and biomass burning. Several studies indicate that wetland CH_4 emissions are highly sensitive to temperature and are also affected by hydrological changes. Available model estimates all indicate increases in wetland emissions due to future climate change but vary widely in the magnitude of such a positive feedback effect. {7.4}

The N_2O concentration in 2005 was 319 ppb, about 18% higher than its pre-industrial value. Nitrous oxide increased approximately linearly by about 0.8 ppb yr^{-1} over the past few decades. Ice core data show that the atmospheric concentration of N_2O varied by less than about 10 ppb for 11,500 years before the onset of the industrial period. {2.3, 6.4, 6.5}

The increase in N_2O since the pre-industrial era now contributes a radiative forcing of +0.16 ± 0.02 W m^{-2} and is due primarily to human activities, particularly agriculture and associated land use change. Current estimates are that about 40% of total N_2O emissions are anthropogenic but individual source estimates remain subject to significant uncertainties. {2.3, 7.4}

TS.2.1.3 Changes in Atmospheric Halocarbons, Stratospheric Ozone, Tropospheric Ozone and Other Gases

CFCs and hydrochlorofluorocarbons (HCFCs) are greenhouse gases that are purely anthropogenic in origin and used in a wide variety of applications. Emissions of these gases have decreased due to their phase-out under the Montreal Protocol, and the atmospheric concentrations of CFC-11 and CFC-113 are now decreasing due to natural removal processes. Observations in polar firn cores since the TAR have now extended the available time series information for some of these greenhouse gases. Ice core and *in situ* data confirm that industrial sources are the cause of observed atmospheric increases in CFCs and HCFCs. {2.3}

The Montreal Protocol gases contributed +0.32 ± 0.03 W m^{-2} to direct radiative forcing in 2005, with CFC-12 continuing to be the third most important long-lived radiative forcing agent. These gases as a group contribute about 12% of the total forcing due to LLGHGs. {2.3}

The concentrations of industrial fluorinated gases covered by the Kyoto Protocol (hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6)) are relatively small but are increasing rapidly. Their total radiative forcing in 2005 was +0.017 W m^{-2}. {2.3}

Tropospheric ozone is a short-lived greenhouse gas produced by chemical reactions of precursor species in the atmosphere and with large spatial and temporal variability. Improved measurements and modelling have advanced the understanding of chemical precursors that lead to the formation of tropospheric ozone, mainly carbon monoxide, nitrogen oxides (including sources and possible long-term trends in lightning) and formaldehyde. Overall, current models are successful in describing the principal features of the present global tropospheric ozone distribution on the basis of underlying processes. New satellite and *in situ* measurements provide important global constraints for these models; however, there is less confidence in their ability to reproduce the changes in ozone associated with large changes in emissions or climate, and in the simulation of observed long-term trends in ozone concentrations over the 20th century. {7.4}

Tropospheric ozone radiative forcing is estimated to be +0.35 [+0.25 to +0.65] W m^{-2} with a *medium* level of scientific understanding. The best estimate of this radiative forcing has not changed since the TAR. Observations show that trends in tropospheric ozone during the last few decades vary in sign and magnitude at many locations, but there are indications of significant upward trends at low latitudes. Model studies of the radiative forcing due to the increase in tropospheric ozone since pre-industrial times have increased in complexity and comprehensiveness compared with models used in the TAR. {2.3, 7.4}

Changes in tropospheric ozone are linked to air quality and climate change. A number of studies have shown that summer daytime ozone concentrations correlate strongly with temperature. This correlation appears to reflect contributions from temperature-dependent biogenic volatile organic carbon emissions, thermal decomposition of peroxyacetylnitrate, which acts as a reservoir for nitrogen oxides (NO_x), and association of high temperatures with regional stagnation. Anomalously hot and stagnant conditions during the summer of 1988 were responsible for the highest surface-level ozone year on record in the north-eastern USA. The summer heat wave in Europe in 2003 was also associated with exceptionally high local ozone at the surface. {Box 7.4}

The radiative forcing due to the destruction of stratospheric ozone is caused by the Montreal Protocol gases and is re-evaluated to be –0.05 ± 0.10 W m^{-2}, weaker than in the TAR, with a medium level of scientific understanding. The trend of greater and greater depletion of global stratospheric ozone observed during the 1980s and 1990s is no longer occurring; however, global stratospheric ozone is still about 4% below pre-1980 values and it is not yet clear whether ozone recovery has begun. In addition to the chemical destruction of ozone, dynamical changes may have contributed to NH mid-latitude ozone reduction. {2.3}

Direct emission of water vapour by human activities makes a negligible contribution to radiative forcing. However, as global mean temperatures increase, tropospheric water vapour concentrations increase and this represents a key feedback but not a forcing of climate change. Direct emission of water to the atmosphere by anthropogenic activities, mainly irrigation, is a possible forcing factor but corresponds to less than 1% of the natural sources of atmospheric water vapour. The direct injection of water vapour into the atmosphere from fossil fuel combustion is significantly lower than that from agricultural activity. {2.5}

Based on chemical transport model studies, the radiative forcing from increases in stratospheric water vapour due to oxidation of CH_4 is estimated to be +0.07 ± 0.05 W m^{-2}. The level of scientific understanding is low because the contribution of CH_4 to the corresponding vertical structure of the water vapour change near the tropopause is uncertain. Other potential human causes of stratospheric water vapour increases that could contribute to radiative forcing are poorly understood. {2.3}

TS.2.2 Aerosols

Direct aerosol radiative forcing is now considerably better quantified than previously and represents a major advance in understanding since the time of the TAR, when several components had a very low level of scientific understanding. A total direct aerosol radiative forcing combined across all aerosol types can now be given for the first time as –0.5 ± 0.4 W m^{-2}, with a medium-low level of scientific understanding. Atmospheric models have improved and many now represent all aerosol components of significance. Aerosols vary considerably in their properties that affect the extent to which they absorb and scatter radiation, and thus different types may have a net cooling or warming effect. Industrial aerosol consisting mainly of a mixture of sulphates, organic and black carbon, nitrates and industrial dust is clearly discernible over many continental regions of the NH. Improved *in situ*, satellite and surface-based measurements (see Figure TS.4) have enabled verification of global aerosol model simulations. These improvements allow quantification of the total direct aerosol radiative forcing for the first time, representing an important advance since the TAR. The direct radiative forcing for individual species remains less certain and is estimated from models to be –0.4 ± 0.2 W m^{-2} for sulphate, –0.05 ± 0.05 W m^{-2} for fossil fuel organic carbon, +0.2 ± 0.15 W m^{-2} for fossil fuel black carbon, +0.03 ± 0.12 W m^{-2} for biomass burning, –0.1 ± 0.1 W m^{-2} for nitrate and –0.1 ± 0.2 W m^{-2} for mineral dust. Two recent emission inventory studies support data from ice cores and suggest that global anthropogenic sulphate emissions decreased over the 1980 to 2000 period and that the geographic distribution of sulphate forcing has also changed. {2.4, 6.6}

Significant changes in the estimates of the direct radiative forcing due to biomass-burning, nitrate and mineral dust aerosols have occurred since the TAR. For biomass-burning aerosol, the estimated direct radiative forcing is now revised from being negative to near zero due to the estimate being strongly influenced by the occurrence of these aerosols over clouds. For the first time, the radiative forcing due to nitrate aerosol is given. For mineral dust, the range in the direct radiative forcing is reduced due to a reduction in the estimate of its anthropogenic fraction. {2.4}

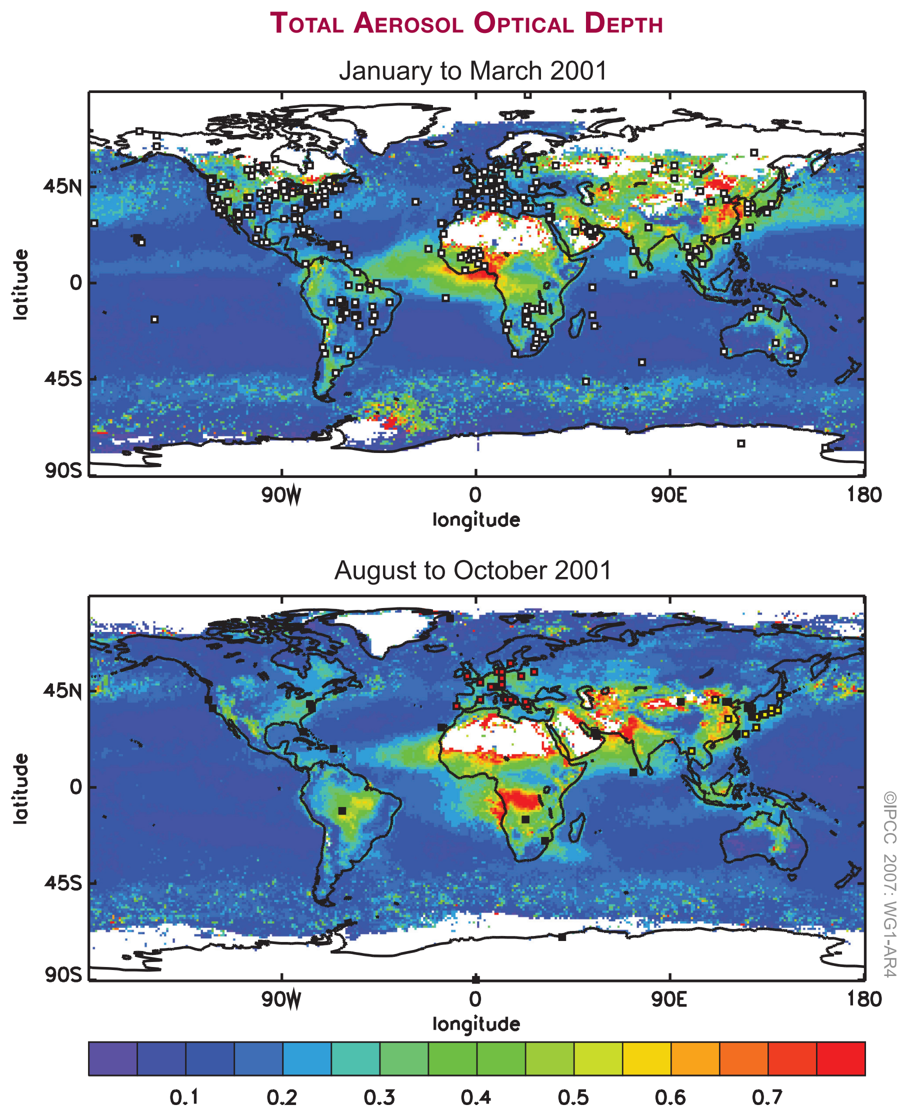


Figure TS.4. *(Top) The total aerosol optical depth (due to natural plus anthropogenic aerosols) at a mid-visible wavelength determined by satellite measurements for January to March 2001 and (bottom) August to October 2001, illustrating seasonal changes in industrial and biomass-burning aerosols. Data are from satellite measurements, complemented by two different kinds of ground-based measurements at locations shown in the two panels (see Section 2.4.2 for details). {Figure 2.11}*

Anthropogenic aerosols effects on water clouds cause an indirect cloud albedo effect (referred to as the first indirect effect in the TAR), which has a best estimate for the first time of –0.7 [–0.3 to –1.8] W m^{-2}. The number of global model estimates of the albedo effect for liquid water clouds has increased substantially since the TAR, and the estimates have been evaluated in a more rigorous way. The estimate for this radiative forcing comes from multiple model studies incorporating more aerosol species and describing aerosol-cloud interaction processes in greater detail. Model studies including more aerosol species or constrained by satellite observations tend to yield a relatively weaker cloud albedo effect. Despite the advances and progress since the TAR and the reduction in the spread of the estimate of the forcing, there remain large uncertainties in both measurements and modelling of processes, leading to a low level of scientific understanding, which is an elevation from the very low rank in the TAR. {2.4, 7.5, 9.2}

Other effects of aerosol include a cloud lifetime effect, a semi-direct effect and aerosol-ice cloud interactions. These are considered to be part of the climate response rather than radiative forcings. {2.4, 7.5}

TS.2.3 Aviation Contrails and Cirrus, Land Use and Other Effects

Persistent linear contrails from global aviation contribute a small radiative forcing of +0.01 [+0.003 to +0.03] W m^{-2}, with a low level of scientific understanding. This best estimate is smaller than the estimate in the TAR. This difference results from new observations of contrail cover and reduced estimates of contrail optical depth. No best estimates are available for the net forcing from spreading contrails. Their effects on cirrus cloudiness and the global effect of aviation aerosol on background cloudiness remain unknown. {2.6}

Human-induced changes in land cover have increased the global surface albedo, leading to a radiative forcing of –0.2 ± 0.2 W m^{-2}, the same as in the TAR, with a medium-low level of scientific understanding. Black carbon aerosols deposited on snow reduce the surface albedo and are estimated to yield an associated radiative forcing of +0.1 ± 0.1 W m^{-2}, with a low level of scientific understanding. Since the TAR, a number of estimates of the forcing from land use changes have been made, using better techniques, exclusion of feedbacks in the evaluation and improved incorporation of large-scale observations. Uncertainties in the estimate include mapping and characterisation of present-day vegetation and historical state, parametrization of surface radiation processes and biases in models' climate variables. The presence of soot particles in snow leads to a decrease in the albedo of snow and a positive forcing, and could affect snowmelt. Uncertainties are large regarding the manner in which soot is incorporated in snow and the resulting optical properties. {2.5}

The impacts of land use change on climate are expected to be locally significant in some regions, but are small at the global scale in comparison with greenhouse gas warming. Changes in the land surface (vegetation, soils, water) resulting from human activities can significantly affect local climate through shifts in radiation, cloudiness, surface roughness and surface temperatures. Changes in vegetation cover can also have a substantial effect on surface energy and water balance at the regional scale. These effects involve non-radiative processes (implying that they cannot be quantified by a radiative forcing) and have a very low level of scientific understanding. {2.5, 7.2, 9.3, Box 11.4}

The release of heat from anthropogenic energy production can be significant over urban areas but is not significant globally. {2.5}

TS.2.4 Radiative Forcing Due to Solar Activity and Volcanic Eruptions

Continuous monitoring of total solar irradiance now covers the last 28 years. The data show a well-established 11-year cycle in irradiance that varies by 0.08% from solar cycle minima to maxima, with no significant long-term trend. New data have more accurately quantified changes in solar spectral fluxes over a broad range of wavelengths in association with changing solar activity. Improved calibrations using high-quality overlapping measurements have also contributed to a better understanding. Current understanding of solar physics and the known sources of irradiance variability suggest comparable irradiance levels during the past two solar cycles, including at solar minima. The primary known cause of contemporary irradiance variability is the presence on the Sun's disk of sunspots (compact, dark features where radiation is locally depleted) and faculae (extended bright features where radiation is locally enhanced). {2.7}

The estimated direct radiative forcing due to changes in the solar output since 1750 is +0.12 [+0.06 to +0.3] W m^{-2}, which is less than half of the estimate given in the TAR, with a low level of scientific understanding. The reduced radiative forcing estimate comes from a re-evaluation of the long-term change in solar irradiance since 1610 (the Maunder Minimum) based upon: a new reconstruction using a model of solar magnetic flux variations that does not invoke geomagnetic, cosmogenic or stellar proxies; improved understanding of recent solar variations and their relationship to physical processes; and re-evaluation of the variations of Sun-like stars. While this leads to an elevation in the level of scientific understanding from very low in the TAR to low in this assessment, uncertainties remain large because of the lack of direct observations and incomplete understanding of solar variability mechanisms over long time scales. {2.7, 6.6}

Empirical associations have been reported between solar-modulated cosmic ray ionization of the atmosphere and global average low-level cloud cover but evidence for a systematic indirect solar effect remains ambiguous. It has been suggested that galactic cosmic rays with sufficient energy to reach the troposphere could alter the population of cloud condensation nuclei and hence microphysical cloud properties (droplet number and concentration), inducing changes in cloud processes analogous to the indirect cloud albedo effect of tropospheric aerosols and thus causing an indirect solar forcing of climate. Studies have probed various correlations with clouds in particular regions or using limited cloud types or limited time periods; however, the cosmic ray time series does not appear to correspond to global total cloud cover after 1991 or to global low-level cloud cover after 1994. Together with the lack of a proven physical mechanism and the plausibility of other causal factors affecting changes in cloud cover, this makes the association between galactic cosmic ray-induced changes in aerosol and cloud formation controversial. {2.7}

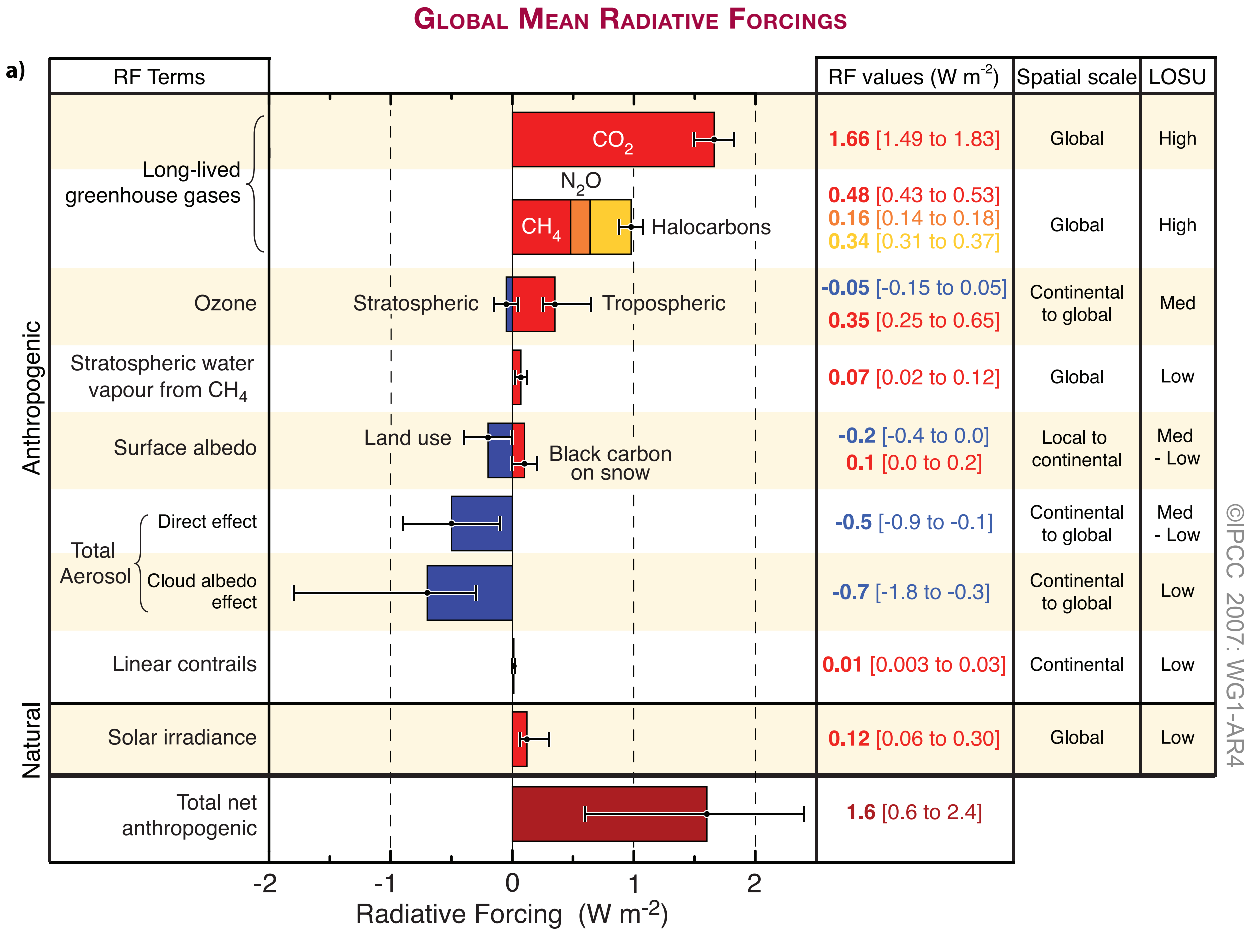
Explosive volcanic eruptions greatly increase the concentration of stratospheric sulphate aerosols. A single eruption can thereby cool global mean climate for a few years. Volcanic aerosols perturb both the stratosphere and surface/troposphere radiative energy budgets and climate in an episodic manner, and many past events are evident in ice core observations of sulphate as well as temperature records. There have been no explosive volcanic events since the 1991 Mt. Pinatubo eruption capable of injecting significant material to the stratosphere. However, the potential exists for volcanic eruptions much larger than the 1991 Mt. Pinatubo eruption, which could produce larger radiative forcing and longer-term cooling of the climate system. {2.7, 6.4, 6.6, 9.2}

TS.2.5 Net Global Radiative Forcing, Global Warming Potentials and Patterns of Forcing

The understanding of anthropogenic warming and cooling influences on climate has improved since the TAR, leading to *very high confidence* that the effect of human activities since 1750 has been a net positive forcing of +1.6 [+0.6 to +2.4] W m^{-2}. Improved understanding and better quantification of the forcing mechanisms since the TAR make it possible to derive a combined net anthropogenic radiative forcing for the first time. Combining the component values for each forcing agent and their uncertainties yields the probability distribution of the combined anthropogenic radiative forcing estimate shown in Figure TS.5; the most likely value is about an order of magnitude larger than the estimated radiative forcing from changes in solar irradiance. Since the range in the estimate is +0.6 to +2.4 W m^{-2}, there is very high confidence in the net positive radiative forcing of the climate system due to human activity. The LLGHGs together contribute +2.63 ± 0.26 W m^{-2}, which is the dominant radiative forcing term and has the highest level of scientific understanding. In contrast, the total direct aerosol, cloud albedo and surface albedo effects that contribute negative forcings are less well understood and have larger uncertainties. The range in the net estimate is increased by the negative forcing terms, which have larger uncertainties than the positive terms. The nature of the uncertainty in the estimated cloud albedo effect introduces a noticeable asymmetry in the distribution. Uncertainties in the distribution include structural aspects (e.g., representation of extremes in the component values, absence of any weighting of the radiative forcing mechanisms, possibility of unaccounted for but as yet unquantified radiative forcings) and statistical aspects (e.g., assumptions about the types of distributions describing component uncertainties). {2.7, 2.9}

The Global Warming Potential (GWP) is a useful metric for comparing the potential climate impact of the emissions of different LLGHGs (see Table TS.2). Global Warming Potentials compare the integrated radiative forcing over a specified period (e.g., 100 years) from a unit mass pulse emission and are a way of comparing the potential climate change associated with emissions of different greenhouse gases. There are well-documented shortcomings of the GWP concept, particularly in using it to assess the impact of short-lived species. {2.10}

For the magnitude and range of realistic forcings considered, evidence suggests an approximately linear relationship between global mean radiative forcing and global mean surface temperature response. The spatial patterns of radiative forcing vary between different forcing agents. However, the spatial signature of the climate response is not generally expected to match that of the forcing. Spatial patterns of climate response



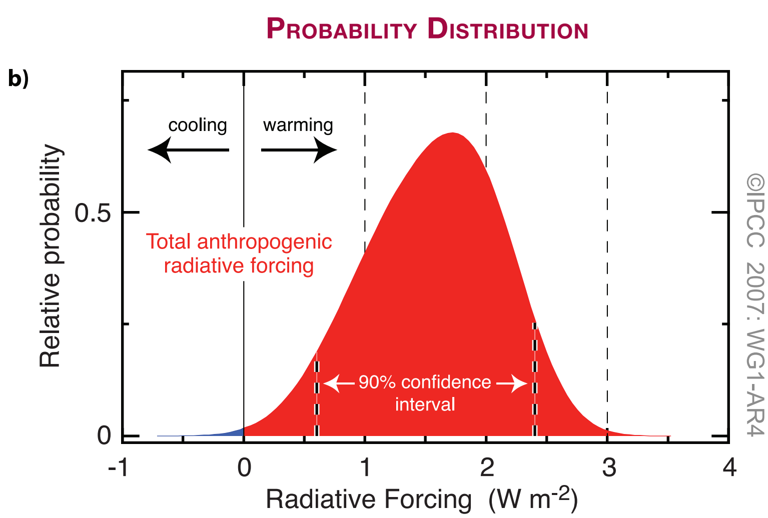


Figure TS.5. *(a) Global mean radiative forcings (RF) and their 90% confidence intervals in 2005 for various agents and mechanisms. Columns on the right-hand side specify best estimates and confidence intervals (RF values); typical geographical extent of the forcing (Spatial scale); and level of scientific understanding (LOSU) indicating the scientific confidence level as explained in Section 2.9. Errors for CH_4, N_2O and halocarbons have been combined. The net anthropogenic radiative forcing and its range are also shown. Best estimates and uncertainty ranges can not be obtained by direct addition of individual terms due to the asymmetric uncertainty ranges for some factors; the values given here were obtained from a Monte Carlo technique as discussed in Section 2.9. Additional forcing factors not included here are considered to have a very low LOSU. Volcanic aerosols contribute an additional form of natural forcing but are not included due to their episodic nature. The range for linear contrails does not include other possible effects of aviation on cloudiness. (b) Probability distribution of the global mean combined radiative forcing from all anthropogenic agents shown in (a). The distribution is calculated by combining the best estimates and uncertainties of each component. The spread in the distribution is increased significantly by the negative forcing terms, which have larger uncertainties than the positive terms. {2.9.1, 2.9.2; Figure 2.20}*

Table TS.2. *Lifetimes, radiative efficiencies and direct (except for CH_4) global warming potentials (GWP) relative to CO_2. {Table 2.14}*

Industrial Designation or Common Name (years)	Chemical Formula	Lifetime (years)	Radiative Efficiency ($W\ m^{-2}\ ppb^{-1}$)	Global Warming Potential for Given Time Horizon			
				SAR‡ (100-yr)	20-yr	100-yr	500-yr
Carbon dioxide	CO_2	See below[a]	[b]$1.4x10^{-5}$	1	1	1	1
Methane[c]	CH_4	12[c]	$3.7x10^{-4}$	21	72	25	7.6
Nitrous oxide	N_2O	114	$3.03x10^{-3}$	310	289	298	153
Substances controlled by the Montreal Protocol							
CFC-11	CCl_3F	45	0.25	3,800	6,730	4,750	1,620
CFC-12	CCl_2F_2	100	0.32	8,100	11,000	10,900	5,200
CFC-13	$CClF_3$	640	0.25		10,800	14,400	16,400
CFC-113	CCl_2FCClF_2	85	0.3	4,800	6,540	6,130	2,700
CFC-114	$CClF_2CClF_2$	300	0.31		8,040	10,000	8,730
CFC-115	$CClF_2CF_3$	1,700	0.18		5,310	7,370	9,990
Halon-1301	$CBrF_3$	65	0.32	5,400	8,480	7,140	2,760
Halon-1211	$CBrClF_2$	16	0.3		4,750	1,890	575
Halon-2402	$CBrF_2CBrF_2$	20	0.33		3,680	1,640	503
Carbon tetrachloride	CCl_4	26	0.13	1,400	2,700	1,400	435
Methyl bromide	CH_3Br	0.7	0.01		17	5	1
Methyl chloroform	CH_3CCl_3	5	0.06		506	146	45
HCFC-22	$CHClF_2$	12	0.2	1,500	5,160	1,810	549
HCFC-123	$CHCl_2CF_3$	1.3	0.14	90	273	77	24
HCFC-124	$CHClFCF_3$	5.8	0.22	470	2,070	609	185
HCFC-141b	CH_3CCl_2F	9.3	0.14		2,250	725	220
HCFC-142b	CH_3CClF_2	17.9	0.2	1,800	5,490	2,310	705
HCFC-225ca	$CHCl_2CF_2CF_3$	1.9	0.2		429	122	37
HCFC-225cb	$CHClFCF_2CClF_2$	5.8	0.32		2,030	595	181
Hydrofluorocarbons							
HFC-23	CHF_3	270	0.19	11,700	12,000	14,800	12,200
HFC-32	CH_2F_2	4.9	0.11	650	2,330	675	205
HFC-125	CHF_2CF_3	29	0.23	2,800	6,350	3,500	1,100
HFC-134a	CH_2FCF_3	14	0.16	1,300	3,830	1,430	435
HFC-143a	CH_3CF_3	52	0.13	3,800	5,890	4,470	1,590
HFC-152a	CH_3CHF_2	1.4	0.09	140	437	124	38
HFC-227ea	CF_3CHFCF_3	34.2	0.26	2,900	5,310	3,220	1,040
HFC-236fa	$CF_3CH_2CF_3$	240	0.28	6,300	8,100	9,810	7,660
HFC-245fa	$CHF_2CH_2CF_3$	7.6	0.28		3,380	1030	314
HFC-365mfc	$CH_3CF_2CH_2CF_3$	8.6	0.21		2,520	794	241
HFC-43-10mee	$CF_3CHFCHFCF_2CF_3$	15.9	0.4	1,300	4,140	1,640	500
Perfluorinated compounds							
Sulphur hexafluoride	SF_6	3,200	0.52	23,900	16,300	22,800	32,600
Nitrogen trifluoride	NF_3	740	0.21		12,300	17,200	20,700
PFC-14	CF_4	50,000	0.10	6,500	5,210	7,390	11,200
PFC-116	C_2F_6	10,000	0.26	9,200	8,630	12,200	18,200

Table TS.2 (continued)

Industrial Designation or Common Name (years)	Chemical Formula	Lifetime (years)	Radiative Efficiency ($W\ m^{-2}\ ppb^{-1}$)	Global Warming Potential for Given Time Horizon SAR‡ (100-yr)	20-yr	100-yr	500-yr
Perfluorinated compounds *(continued)*							
PFC-218	C_3F_8	2,600	0.26	7,000	6,310	8,830	12,500
PFC-318	$c\text{-}C_4F_8$	3,200	0.32	8,700	7,310	10,300	14,700
PFC-3-1-10	C_4F_{10}	2,600	0.33	7,000	6,330	8,860	12,500
PFC-4-1-12	C_5F_{12}	4,100	0.41		6,510	9,160	13,300
PFC-5-1-14	C_6F_{14}	3,200	0.49	7,400	6,600	9,300	13,300
PFC-9-1-18	$C_{10}F_{18}$	>1,000[d]	0.56		>5,500	>7,500	>9,500
trifluoromethyl sulphur pentafluoride	SF_5CF_3	800	0.57		13,200	17,700	21,200
Fluorinated ethers							
HFE-125	CHF_2OCF_3	136	0.44		13,800	14,900	8,490
HFE-134	CHF_2OCHF_2	26	0.45		12,200	6,320	1,960
HFE-143a	CH_3OCF_3	4.3	0.27		2,630	756	230
HCFE-235da2	$CHF_2OCHClCF_3$	2.6	0.38		1,230	350	106
HFE-245cb2	$CH_3OCF_2CHF_2$	5.1	0.32		2,440	708	215
HFE-245fa2	$CHF_2OCH_2CF_3$	4.9	0.31		2,280	659	200
HFE-254cb2	$CH_3OCF_2CHF_2$	2.6	0.28		1,260	359	109
HFE-347mcc3	$CH_3OCF_2CF_2CF_3$	5.2	0.34		1,980	575	175
HFE-347pcf2	$CHF_2CF_2OCH_2CF_3$	7.1	0.25		1,900	580	175
HFE-356pcc3	$CH_3OCF_2CF_2CHF_2$	0.33	0.93		386	110	33
HFE-449sl (HFE-7100)	$C_4F_9OCH_3$	3.8	0.31		1,040	297	90
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	0.77	0.3		207	59	18
HFE-43-10pccc124 (H-Galden 1040x)	$CHF_2OCF_2OC_2F_4OCHF_2$	6.3	1.37		6,320	1,870	569
HFE-236ca12 (HG-10)	$CHF_2OCF_2OCHF_2$	12.1	0.66		8,000	2,800	860
HFE-338pcc13 (HG-01)	$CHF_2OCF_2CF_2OCHF_2$	6.2	0.87		5,100	1,500	460
Perfluoropolyethers							
PFPMIE	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	800	0.65		7,620	10,300	12,400
Hydrocarbons and other compounds – Direct Effects							
Dimethylether	CH_3OCH_3	0.015	0.02		1	1	<<1
Methylene chloride	CH_2Cl_2	0.38	0.03		31	8.7	2.7
Methyl chloride	CH_3Cl	1.0	0.01		45	13	4

Notes:

‡ SAR refers to the IPCC Second Assessment Report (1995) used for reporting under the UNFCCC.

a The CO_2 response function used in this report is based on the revised version of the Bern Carbon cycle model used in Chapter 10 of this report (Bern2.5CC; Joos et al. 2001) using a background CO_2 concentration value of 378 ppm. The decay of a pulse of CO_2 with time t is given by

$a_0 + \sum_{i=1}^{3} a_i \cdot e^{-t/\tau_i}$ where $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, $a_3 = 0.186$, $\tau_1 = 172.9$ years, $\tau_2 = 18.51$ years, and $\tau_3 = 1.186$ years, for $t < 1{,}000$ years.

b The radiative efficiency of CO_2 is calculated using the IPCC (1990) simplified expression as revised in the TAR, with an updated background concentration value of 378 ppm and a perturbation of +1 ppm (see Section 2.10.2).

c The perturbation lifetime for CH_4 is 12 years as in the TAR (see also Section 7.4). The GWP for CH_4 includes indirect effects from enhancements of ozone and stratospheric water vapour (see Section 2.10) .

d The assumed lifetime of 1000 years is a lower limit.

are largely controlled by climate processes and feedbacks. For example, sea ice-albedo feedbacks tend to enhance the high-latitude response. Spatial patterns of response are also affected by differences in thermal inertia between land and sea areas. {2.8, 9.2}

The pattern of response to a radiative forcing can be altered substantially if its structure is favourable for affecting a particular aspect of the atmospheric structure or circulation. Modelling studies and data comparisons suggest that mid- to high-latitude circulation patterns are *likely* to be affected by some forcings such as volcanic eruptions, which have been linked to changes in the Northern Annular Mode (NAM) and North Atlantic Oscillation (NAO) (see Section 3.1 and Box TS.2). Simulations also suggest that absorbing aerosols, particularly black carbon, can reduce the solar radiation reaching the surface and can warm the atmosphere at regional scales, affecting the vertical temperature profile and the large-scale atmospheric circulation. {2.8, 7.5, 9.2}

The spatial patterns of radiative forcings for ozone, aerosol direct effects, aerosol-cloud interactions and land use have considerable uncertainties. This is in contrast to the relatively high confidence in the spatial pattern of radiative forcing for the LLGHGs. The net positive radiative forcing in the Southern Hemisphere (SH) *very likely* exceeds that in the NH because of smaller aerosol concentrations in the SH. {2.9}

TS 2.6 Surface Forcing and the Hydrologic Cycle

Observations and models indicate that changes in the radiative flux at the Earth's surface affect the surface heat and moisture budgets, thereby involving the hydrologic cycle. Recent studies indicate that some forcing agents can influence the hydrologic cycle differently than others through their interactions with clouds. In particular, changes in aerosols may have affected precipitation and other aspects of the hydrologic cycle more strongly than other anthropogenic forcing agents. Energy deposited at the surface directly affects evaporation and sensible heat transfer. The instantaneous radiative flux change at the surface (hereafter called 'surface forcing') is a useful diagnostic tool for understanding changes in the heat and moisture surface budgets and the accompanying climate change. However, unlike radiative forcing, it cannot be used to quantitatively compare the effects of different agents on the equilibrium global mean surface temperature change. Net radiative forcing and surface forcing have different equator-to-pole gradients in the NH, and are different between the NH and SH. {2.9, 7.2, 7.5, 9.5}

TS.3 Observations of Changes in Climate

This assessment evaluates changes in the Earth's climate system, considering not only the atmosphere, but also the ocean and the cryosphere, as well as phenomena such as atmospheric circulation changes, in order to increase understanding of trends, variability and processes of climate change at global and regional scales. Observational records employing direct methods are of variable length as described below, with global temperature estimates now beginning as early as 1850. Observations of extremes of weather and climate are discussed, and observed changes in extremes are described. The consistency of observed changes among different climate variables that allows an increasingly comprehensive picture to be drawn is also described. Finally, palaeoclimatic information that generally employs indirect proxies to infer information about climate change over longer time scales (up to millions of years) is also assessed.

TS.3.1 Atmospheric Changes: Instrumental Record

This assessment includes analysis of global and hemispheric means, changes over land and ocean and distributions of trends in latitude, longitude and altitude. Since the TAR, improvements in observations and their calibration, more detailed analysis of methods and extended time series allow more in-depth analyses of changes including atmospheric temperature, precipitation, humidity, wind and circulation. Extremes of climate are a key expression of climate variability, and this assessment includes new data that permit improved insights into the changes in many types of extreme events including heat waves, droughts, heavy precipitation and tropical cyclones (including hurricanes and typhoons). {3.2–3.4, 3.8}

Furthermore, advances have occurred since the TAR in understanding how a number of seasonal and long-term anomalies can be described by patterns of climate variability. These patterns arise from internal interactions and from the differential effects on the atmosphere of land and ocean, mountains and large changes in heating. Their response is often felt in regions far removed from their physical source through atmospheric teleconnections associated with large-scale waves in the atmosphere. Understanding temperature and precipitation anomalies associated with the dominant patterns of climate variability is essential to understanding many regional climate anomalies and why these may differ from those at the global scale. Changes in storm tracks, the jet streams, regions of preferred blocking anticyclones and changes in monsoons can also occur in conjunction with these preferred patterns of variability. {3.5–3.7}

TS.3.1.1 Global Average Temperatures

2005 and 1998 were the warmest two years in the instrumental global surface air temperature record since 1850. Surface temperatures in 1998 were enhanced by the major 1997–1998 El Niño but no such strong anomaly was present in 2005. Eleven of the last 12 years (1995 to 2006) – the exception being 1996 – rank among the 12 warmest years on record since 1850. {3.2}

The global average surface temperature has increased, especially since about 1950. The updated 100-year trend (1906–2005) of 0.74°C ± 0.18°C is larger than the 100-year warming trend at the time of the TAR (1901–2000) of 0.6°C ± 0.2°C due to additional warm years. The total temperature increase from 1850-1899 to 2001-2005 is 0.76°C ± 0.19°C. The rate of warming averaged over the last 50 years (0.13°C ± 0.03°C per decade) is nearly twice that for the last 100 years. Three different global estimates all show consistent warming trends. There is also consistency between the data sets in their separate land and ocean domains, and between sea surface temperature (SST) and nighttime marine air temperature (see Figure TS.6). {3.2}

Recent studies confirm that effects of urbanisation and land use change on the global temperature record are negligible (less than 0.006°C per decade over land and zero over the ocean) as far as hemispheric- and continental-scale averages are concerned. All observations are subject to data quality and consistency checks to correct for potential biases. The real but local effects of urban areas are accounted for in the land temperature data sets used. Urbanisation and land use effects are not relevant to the widespread oceanic warming that has been observed. Increasing evidence suggests that urban heat island effects also affect precipitation, cloud and diurnal temperature range (DTR). {3.2}

The global average DTR has stopped decreasing. A decrease in DTR of approximately 0.1°C per decade was reported in the TAR for the period 1950 to 1993. Updated observations reveal that DTR has not changed from 1979 to 2004 as both day- and night time temperature have risen at about the same rate. The trends are highly variable from one region to another. {3.2}

New analyses of radiosonde and satellite measurements of lower- and mid-tropospheric temperature show warming rates that are generally consistent with each other and with those in the surface temperature record within their respective uncertainties for the periods 1958 to 2005 and 1979 to 2005. This largely resolves a discrepancy noted in the TAR (see Figure TS.7). The radiosonde record is markedly less spatially complete than the surface record and increasing evidence suggests that a number of radiosonde data sets are unreliable, especially in the tropics. Disparities remain among different tropospheric temperature trends estimated from satellite Microwave Sounding Unit (MSU) and advanced MSU measurements since 1979, and all likely still contain residual errors. However, trend estimates have been substantially improved and data set differences reduced since the TAR, through adjustments for changing satellites, orbit decay and drift in local crossing time (diurnal cycle effects). It appears that the satellite tropospheric temperature record is broadly consistent with surface temperature trends provided that the stratospheric influence on MSU channel 2 is accounted for. The range across different data sets of global surface warming since 1979 is 0.16°C to 0.18°C per decade, compared to 0.12°C to 0.19°C per decade for MSU-derived estimates of tropospheric temperatures. It is likely that there is increased warming with altitude from the surface through much of the troposphere in the tropics, pronounced cooling in the stratosphere, and a trend towards a higher tropopause. {3.4}

Stratospheric temperature estimates from adjusted radiosondes, satellites and reanalyses are all in qualitative agreement, with a cooling of between 0.3°C and 0.6°C per decade since 1979 (see Figure TS.7). Longer radiosonde records (back to 1958) also indicate stratospheric cooling but are subject to substantial instrumental uncertainties. The rate of cooling increased after 1979 but has slowed in the last decade. It is *likely* that radiosonde records overestimate stratospheric cooling, owing to changes in sondes not yet taken into account. The trends are not monotonic, because of stratospheric warming episodes that follow major volcanic eruptions. {3.4}

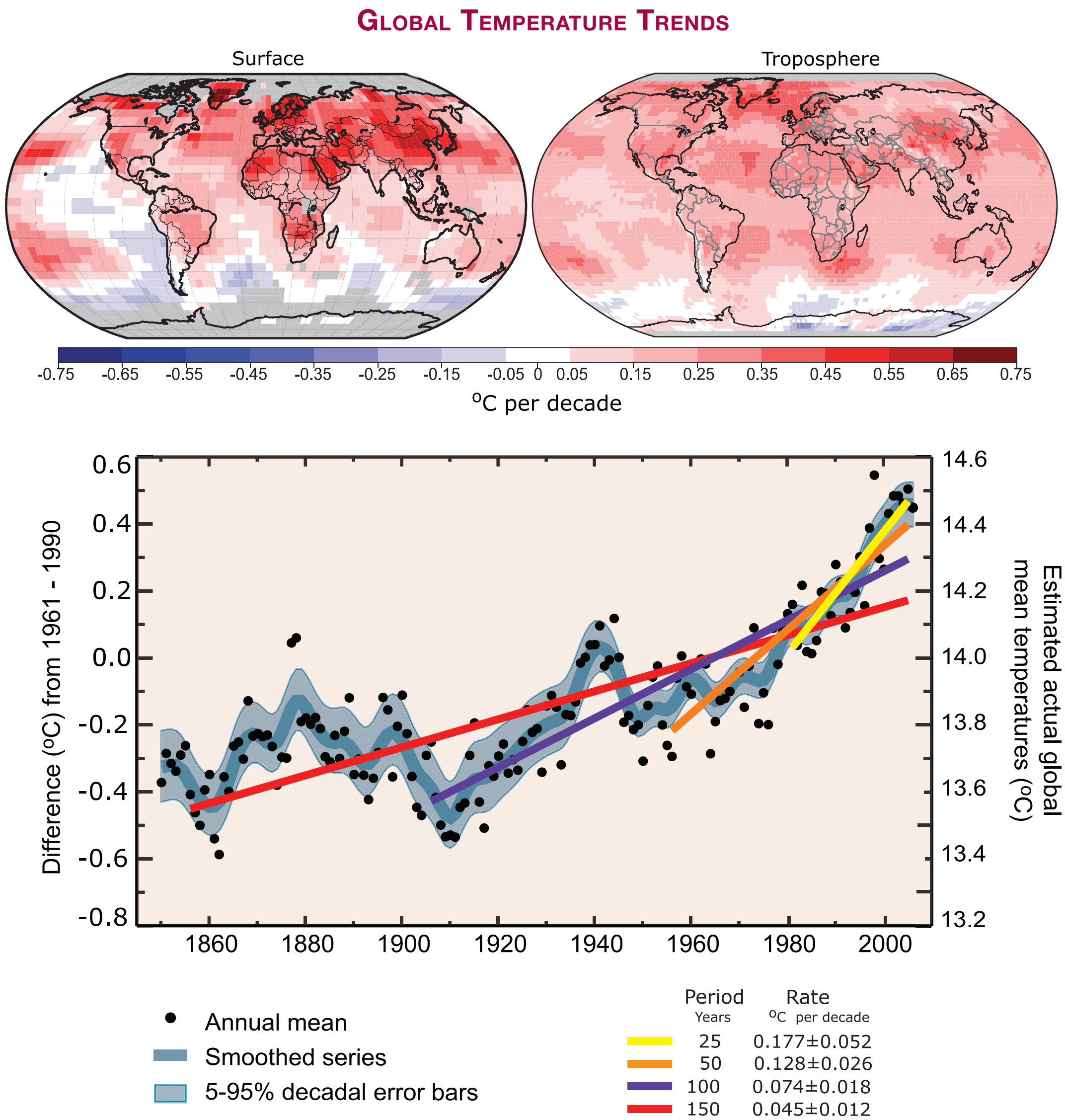


Figure TS.6. *(Top) Patterns of linear global temperature trends over the period 1979 to 2005 estimated at the surface (left), and for the troposphere from satellite records (right). Grey indicates areas with incomplete data. (Bottom) Annual global mean temperatures (black dots) with linear fits to the data. The left hand axis shows temperature anomalies relative to the 1961 to 1990 average and the right hand axis shows estimated actual temperatures, both in °C. Linear trends are shown for the last 25 (yellow), 50 (orange), 100 (purple) and 150 years (red). The smooth blue curve shows decadal variations (see Appendix 3.A), with the decadal 90% error range shown as a pale blue band about that line. The total temperature increase from the period 1850 to 1899 to the period 2001 to 2005 is 0.76°C ± 0.19°C. {FAQ 3.1, Figure 1.}*

TS.3.1.2 Spatial Distribution of Changes in Temperature, Circulation and Related Variables

Surface temperatures over land regions have warmed at a faster rate than over the oceans in both hemispheres. Longer records now available show significantly faster rates of warming over land than ocean in the past two decades (about 0.27°C vs. 0.13°C per decade). {3.2}

The warming in the last 30 years is widespread over the globe, and is greatest at higher northern latitudes. The greatest warming has occurred in the NH winter (DJF) and spring (MAM). Average arctic temperatures have been increasing at almost twice the rate of the rest of the world in the past 100 years. However, arctic temperatures are highly variable. A slightly longer arctic warm period, almost as warm as the present, was observed from 1925 to 1945, but its geographical distribution appears to have been different from the recent warming since its extent was not global. {3.2}

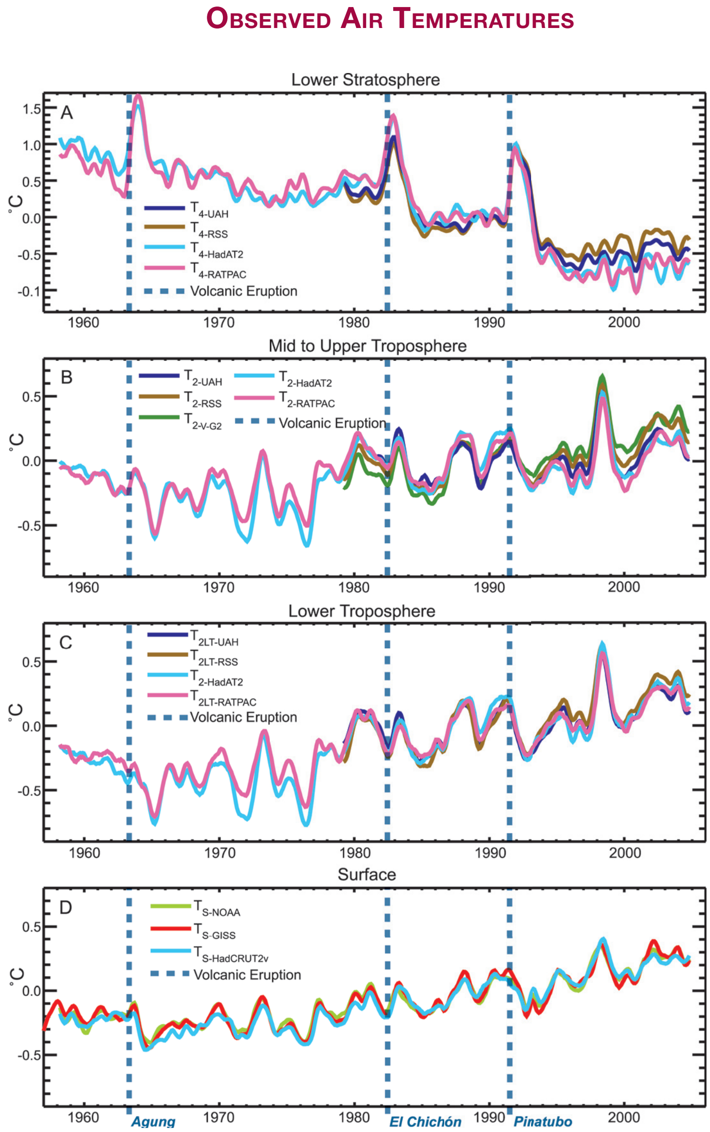


Figure TS.7. *Observed surface (D) and upper air temperatures for the lower troposphere (C), mid- to upper troposphere (B) and lower stratosphere (A), shown as monthly mean anomalies relative to the period 1979 to 1997 smoothed with a seven-month running mean filter. Dashed lines indicate the times of major volcanic eruptions. {Figure 3.17}*

There is evidence for long-term changes in the large-scale atmospheric circulation, such as a poleward shift and strengthening of the westerly winds. Regional climate trends can be very different from the global average, reflecting changes in the circulations and interactions of the atmosphere and ocean and the other components of the climate system. Stronger mid-latitude westerly wind maxima have occurred in both hemispheres in most seasons from at least 1979 to the late 1990s, and poleward displacements of corresponding Atlantic and southern polar front jet streams have been documented. The westerlies in the NH increased from the 1960s to the 1990s but have since returned to values close to the long-term average. The increased strength of the westerlies in the NH changes the flow from oceans to continents, and is a major factor in the observed winter changes in storm tracks and related patterns of precipitation and temperature trends at mid- and high-latitudes. Analyses of wind and significant wave height support reanalysis-based evidence for changes in NH extratropical storms from the start of the reanalysis record in the late 1970s until the late 1990s. These changes are accompanied by a tendency towards stronger winter polar vortices throughout the troposphere and lower stratosphere. {3.2, 3.5}

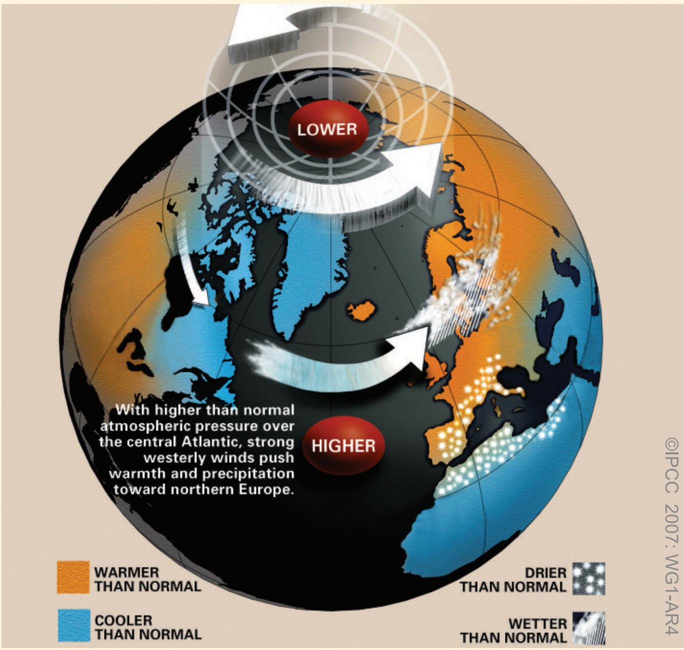
Many regional climate changes can be described in terms of preferred patterns of climate variability and therefore as changes in the occurrence of indices that characterise the strength and phase of these patterns. The importance, over all time scales, of fluctuations in the westerlies and storm tracks in the North Atlantic has often been noted, and these fluctuations are described by the NAO (see Box TS.2 for an explanation of this and other preferred patterns). The characteristics of fluctuations in the zonally averaged westerlies in the two hemispheres have more recently been described by their respective 'annular modes', the Northern and Southern Annular Modes (NAM and SAM). The observed changes can be expressed as a shift of the circulation towards the structure associated with one sign of these preferred patterns. The increased mid-latitude westerlies in the North Atlantic can be largely viewed as reflecting either NAO or NAM changes; multi-decadal variability is also evident in the Atlantic, both in the atmosphere and the ocean. In the SH, changes in circulation related to an increase in the SAM from the 1960s to the present are associated with strong warming over the Antarctic Peninsula and, to a lesser extent, cooling over parts of continental Antarctica. Changes have also been observed in ocean-atmosphere interactions in the Pacific. The ENSO is the dominant mode of global-scale variability on interannual time scales although there have been times when it is less apparent. The 1976–1977 climate shift, related to the phase change in the Pacific Decadal Oscillation (PDO) towards more El Niño events and changes in the evolution of ENSO, has affected many areas, including most tropical monsoons. For instance, over North America, ENSO and Pacific-

Box TS.2: Patterns (Modes) of Climate Variability

Analysis of atmospheric and climatic variability has shown that a significant component of it can be described in terms of fluctuations in the amplitude and sign of indices of a relatively small number of preferred patterns of variability. Some of the best known of these are:

- El Niño-Southern Oscillation (ENSO), a coupled fluctuation in the atmosphere and the equatorial Pacific Ocean, with preferred time scales of two to about seven years. ENSO is often measured by the difference in surface pressure anomalies between Tahiti and Darwin and the SSTs in the central and eastern equatorial Pacific. ENSO has global teleconnections.
- North Atlantic Oscillation (NAO), a measure of the strength of the Icelandic Low and the Azores High, and of the westerly winds between them, mainly in winter. The NAO has associated fluctuations in the storm track, temperature and precipitation from the North Atlantic into Eurasia (see Box TS.2, Figure 1).
- Northern Annular Mode (NAM), a winter fluctuation in the amplitude of a pattern characterised by low surface pressure in the Arctic and strong mid-latitude westerlies. The NAM has links with the northern polar vortex and hence the stratosphere.
- Southern Annular Mode (SAM), the fluctuation of a pattern with low antarctic surface pressure and strong mid-latitude westerlies, analogous to the NAM, but present year round.
- Pacific-North American (PNA) pattern, an atmospheric large-scale wave pattern featuring a sequence of tropospheric high- and low-pressure anomalies stretching from the subtropical west Pacific to the east coast of North America.
- Pacific Decadal Oscillation (PDO), a measure of the SSTs in the North Pacific that has a very strong correlation with the North Pacific Index (NPI) measure of the depth of the Aleutian Low. However, it has a signature throughout much of the Pacific.

Positive Phase of NAO and NAM



Box TS.2, Figure 1. *A schematic of the changes associated with the positive phase of the NAO and NAM. The changes in pressure and winds are shown, along with precipitation changes. Warm colours indicate areas that are warmer than normal and blue indicates areas that are cooler than normal.*

The extent to which all these preferred patterns of variability can be considered to be true modes of the climate system is a topic of active research. However, there is evidence that their existence can lead to larger-amplitude regional responses to forcing than would otherwise be expected. In particular, a number of the observed 20th-century climate changes can be viewed in terms of changes in these patterns. It is therefore important to test the ability of climate models to simulate them (see Section TS.4, Box TS.7) and to consider the extent to which observed changes related to these patterns are linked to internal variability or to anthropogenic climate change. {3.6, 8.4}

North American (PNA) teleconnection-related changes appear to have led to contrasting changes across the continent, as the western part has warmed more than the eastern part, while the latter has become cloudier and wetter. There is substantial low-frequency atmospheric variability in the Pacific sector over the 20th century, with extended periods of weakened (1900–1924; 1947–1976) as well as strengthened (1925–1946; 1977–2003) circulation. {3.2, 3.5, 3.6}

Changes in extremes of temperature are consistent with warming. Observations show widespread reductions in the number of frost days in mid-latitude regions, increases in the number of warm extremes (warmest 10% of days or nights) and a reduction in the number of daily cold extremes (coldest 10% of days or nights) (see Box TS.5). The most marked changes are for cold nights, which have declined over the 1951 to 2003 period for all regions where data are available (76% of the land). {3.8}

Heat waves have increased in duration beginning in the latter half of the 20th century. The record-breaking heat wave over western and central Europe in the summer of 2003 is an example of an exceptional recent extreme. That summer (JJA) was the warmest since comparable instrumental records began around 1780 (1.4°C above the previous warmest in 1807). Spring drying of the land surface over Europe was an important factor in the occurrence of the extreme 2003 temperatures. Evidence suggests that heat waves have also increased in frequency and duration in other locations. The very strong correlation between observed dryness and high temperatures over land in the tropics during summer highlights the important role moisture plays in moderating climate. {3.8, 3.9}

There is insufficient evidence to determine whether trends exist in such events as tornadoes, hail, lightning and dust storms which occur at small spatial scales. {3.8}

Atmospheric Water Vapour

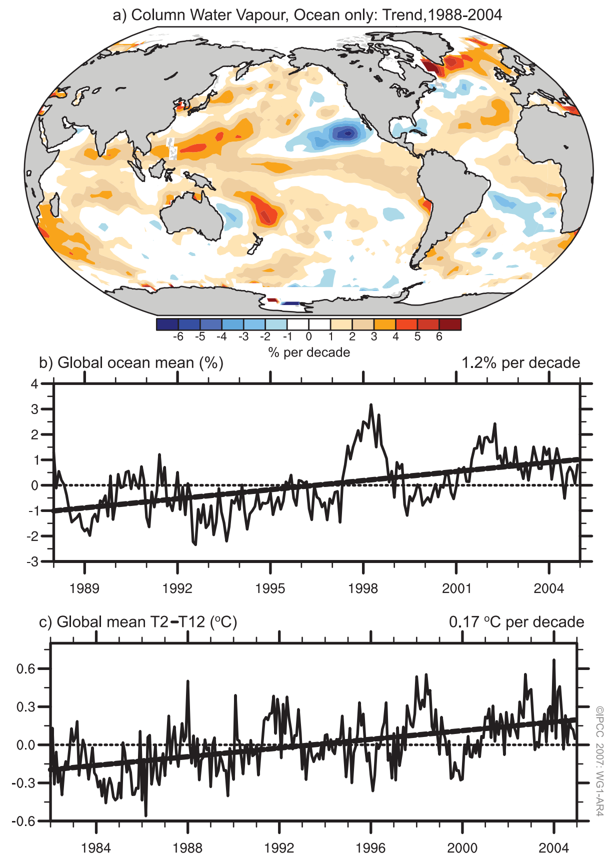


Figure TS.8. *(a) Linear trends in precipitable water (total column water vapour) over the period 1988 to 2004 (% per decade) and (b) the monthly time series of anomalies, relative to the period shown, over the global ocean with linear trend. (c) The global mean (80°N to 80°S) radiative signature of upper-tropospheric moistening is given by monthly time series of combinations of satellite brightness temperature anomalies (°C), relative to the period 1982 to 2004, with the dashed line showing the linear trend of the key brightness temperature in °C per decade. {3.4, Figures 3.20 and 3.21}*

TS.3.1.3 Changes in the Water Cycle: Water Vapour, Clouds, Precipitation and Tropical Storms

Tropospheric water vapour is increasing (Figure TS.8). Surface specific humidity has generally increased since 1976 in close association with higher temperatures over both land and ocean. Total column water vapour has increased over the global oceans by 1.2 ± 0.3% per decade (95% confidence limits) from 1988 to 2004. The observed regional changes are consistent in pattern and amount with the changes in SST and the assumption of a near-constant relative humidity increase in water vapour mixing ratio. The additional atmospheric water vapour implies increased moisture availability for precipitation. {3.4}

Upper-tropospheric water vapour is also increasing. Due to instrumental limitations, it is difficult to assess long-term changes in water vapour in the upper troposphere, where it is of radiative importance. However, the available data now show evidence for global increases in upper-tropospheric specific humidity over the past two decades (Figure TS.8). These observations are consistent with the observed increase in temperatures and represent an important advance since the TAR. {3.4}

Cloud changes are dominated by ENSO. Widespread (but not ubiquitous) decreases in continental DTR have coincided with increases in cloud amounts. Surface and satellite observations disagree on changes in total and low-level cloud changes over the ocean. However, radiation changes at the top of the atmosphere from the 1980s to 1990s (possibly related in part to the ENSO phenomenon) appear to be associated with reductions in tropical upper-level cloud cover, and are consistent with changes in the energy budget and in observed ocean heat content. {3.4}

'Global dimming' is not global in extent and it has not continued after 1990. Reported decreases in solar radiation at the Earth's surface from 1970 to 1990 have an urban bias. Further, there have been increases since about 1990. An increasing aerosol load due to human activities decreases regional air quality and the amount of solar radiation reaching the Earth's surface. In some areas, such as Eastern Europe, recent observations of a reversal in the sign of this effect link changes in solar radiation to concurrent air quality improvements. {3.4}

Long-term trends in precipitation amounts from 1900 to 2005 have been observed in many large regions (Figure TS.9). Significantly increased precipitation has been observed in the eastern parts of North and South America, northern Europe and northern and central Asia. Drying has been observed in the Sahel, the Mediterranean, southern Africa and parts of southern Asia. Precipitation is highly variable spatially and temporally, and robust long-term trends have not been established for other large regions.[5] {3.3}

Substantial increases in heavy precipitation events have been observed. It is *likely* that there have been increases in the number of heavy precipitation events (e.g., above the 95th percentile) in many land regions since about 1950, even in those regions where there has been a reduction in total precipitation amount. Increases have also been reported for rarer precipitation events (1 in 50 year return period), but only a few regions have sufficient data to assess such trends reliably (see Figure TS.10). {3.8}

There is observational evidence for an increase of intense tropical cyclone activity in the North Atlantic since about 1970, correlated with increases in tropical SSTs. There are also suggestions of increased intense tropical cyclone activity in some other regions where concerns over data quality are greater. Multi-decadal variability and the quality of the tropical cyclone records prior to routine satellite observations in about 1970 complicate the detection of long-term trends in tropical cyclone activity and there is no clear trend in the annual numbers of tropical cyclones. Estimates of the potential destructiveness of tropical cyclones suggest a substantial upward trend since the mid-1970s, with a trend towards longer lifetimes and greater intensity. Trends are also apparent in SST, a critical variable known to influence

Global Mean Precipitation

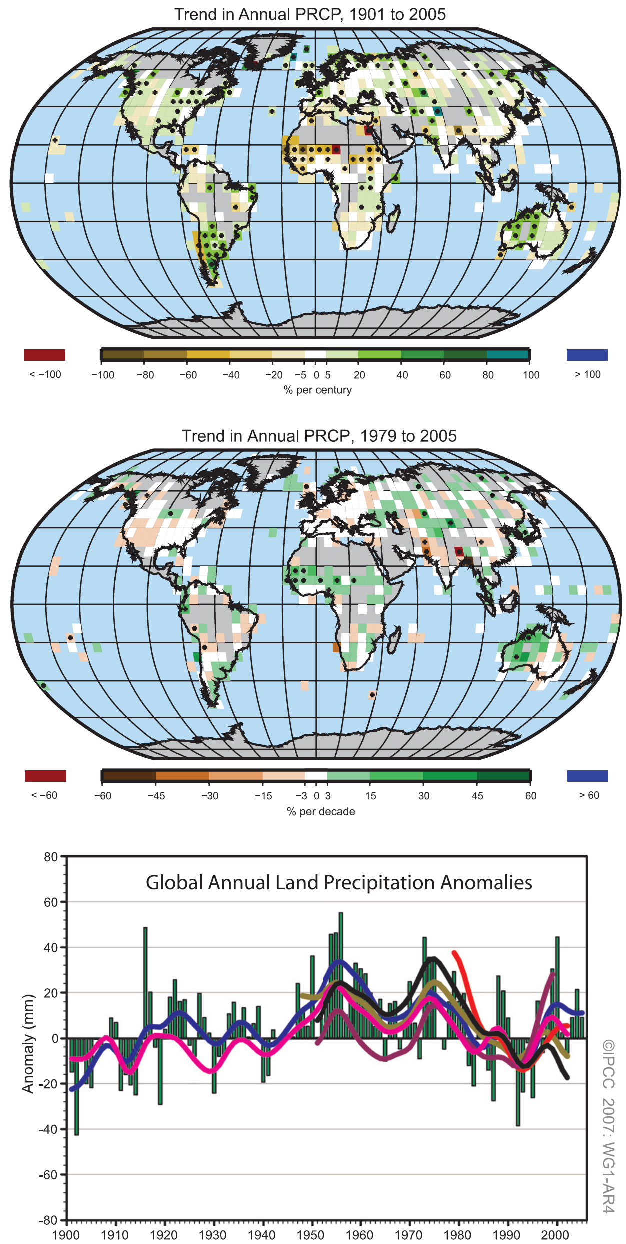


Figure TS.9. *(Top) Distribution of linear trends of annual land precipitation amounts over the period 1901 to 2005 (% per century) and (middle) 1979 to 2005 (% per decade). Areas in grey have insufficient data to produce reliable trends. The percentage is based on the 1961 to 1990 period. (Bottom) Time series of annual global land precipitation anomalies with respect to the 1961 to 1990 base period for 1900 to 2005. The smooth curves show decadal variations (see Appendix 3.A) for different data sets. {3.3, Figures 3.12 and 3.13}*

[5] The assessed regions are those considered in the regional projections chapter of the TAR and in Chapter 11 of this report.

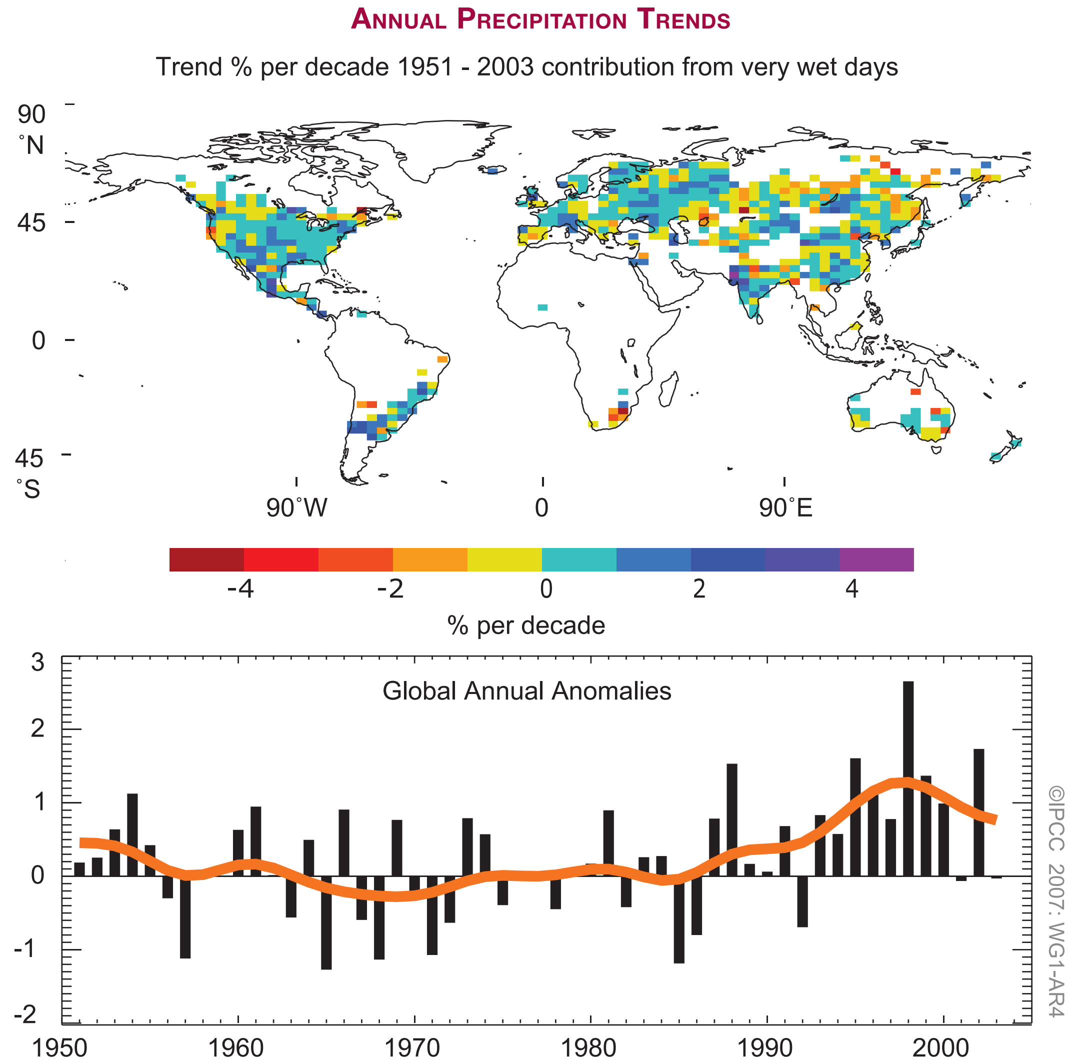


Figure TS.10. *(Top) Observed trends (% per decade) over the period 1951 to 2003 in the contribution to total annual precipitation from very wet days (i.e., corresponding to the 95th percentile and above). White land areas have insufficient data for trend determination. (Bottom) Anomalies (%) of the global (regions with data shown in top panel) annual time series of very wet days (with respect to 1961–1990) defined as the percentage change from the base period average (22.5%). The smooth orange curve shows decadal variations (see Appendix 3.A). {Figure 3.39}*

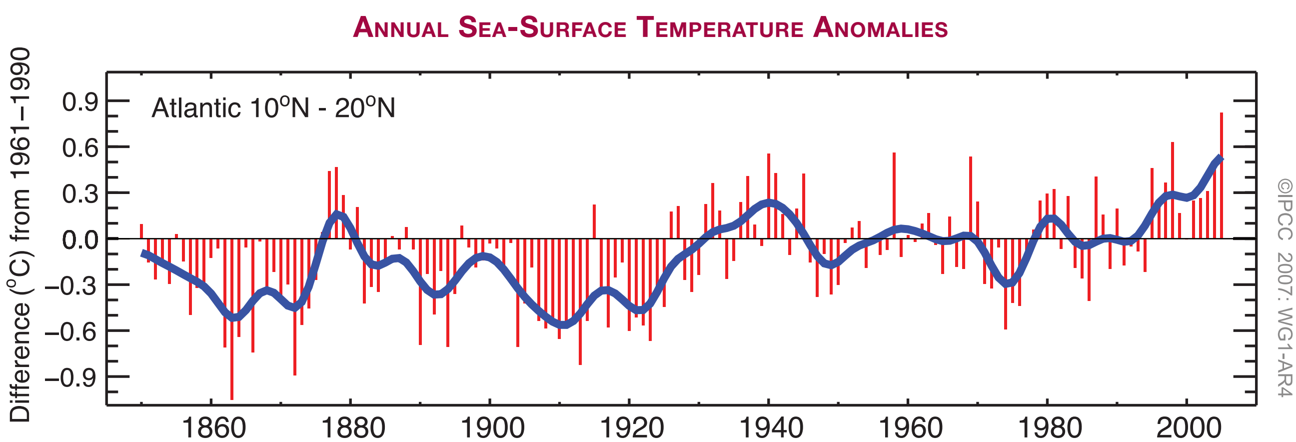


Figure TS.11. *Tropical Atlantic (10°N–20°N) sea surface temperature annual anomalies (°C) in the region of Atlantic hurricane formation, relative to the 1961 to 1990 mean. {Figure 3.33}* tropical cyclone development (see Figure TS.11). Variations in the total numbers of tropical cyclones result from ENSO and decadal variability, which also lead to a redistribution of tropical storm numbers and tracks. The numbers of hurricanes in the North Atlantic have been above normal (based on 1981–2000) in nine of the years from 1995 to 2005. {3.8}

More intense and longer droughts have been observed over wider areas, particularly in the tropics and subtropics since the 1970s. While there are many different measures of drought, many studies use precipitation changes together with temperature.[6] Increased drying due to higher temperatures and decreased land precipitation have contributed to these changes. {3.3}

TS.3.2 Changes in the Cryosphere: Instrumental Record

Currently, ice permanently covers 10% of the land surface, with only a tiny fraction occurring outside Antarctica and Greenland. Ice also covers approximately 7% of the oceans in the annual mean. In midwinter, snow covers approximately 49% of the land surface in the NH. An important property of snow and ice is its high surface albedo. Because up to 90% of the incident solar radiation is reflected by snow and ice surfaces, while only about 10% is reflected by the open ocean or forested lands, changes in snow and ice cover are important feedback mechanisms in climate change. In addition, snow and ice are effective insulators. Seasonally frozen ground is more extensive than snow cover, and its presence is important for energy and moisture fluxes. Therefore, frozen surfaces play important roles in energy and climate processes. {4.1}

The cryosphere stores about 75% of the world's freshwater. At a regional scale, variations in mountain snowpack, glaciers and small ice caps play a crucial role in freshwater availability. Since the change from ice to liquid water occurs at specific temperatures, ice is a component of the climate system that could be subject to abrupt change following sufficient warming. Observations and analyses of changes in ice have expanded and improved since the TAR, including shrinkage of mountain glacier volume, decreases in snow cover, changes in permafrost and frozen ground, reductions in arctic sea ice extent, coastal thinning of the Greenland Ice Sheet exceeding inland thickening from increased snowfall, and reductions in seasonally frozen ground and river and lake ice cover. These allow an improved understanding of how the cryosphere is changing, including its contributions to recent changes in sea level. The periods from 1961 to the present and from 1993 to the present are a focus of this report, due to the availability of directly measured glacier mass balance data and altimetry observations of the ice sheets, respectively. {4.1}

Snow cover has decreased in most regions, especially in spring. Northern Hemisphere snow cover observed by satellite over the 1966 to 2005 period decreased in every month except November and December, with a stepwise drop of 5% in the annual mean in the late 1980s (see Figure TS.12). In the SH, the few long records or proxies mostly show either decreases or no changes in the past 40 years or more. Northern Hemisphere April snow cover extent is strongly correlated with 40°N to 60°N April temperature, reflecting the feedback between snow and temperature. {4.2}

Decreases in snowpack have been documented in several regions worldwide based upon annual time series of mountain snow water equivalent and snow depth. Mountain snow can be sensitive to small changes in temperature, particularly in temperate climatic zones where the transition from rain to snow is generally closely associated with the altitude of the freezing level. Declines in mountain snowpack in western North America and in the Swiss Alps are largest at lower, warmer elevations. Mountain snow water equivalent has declined since 1950 at 75% of the stations monitored in western North America. Mountain snow depth has also declined in the Alps and in southeastern Australia. Direct observations of snow depth are too limited to determine changes in the Andes, but temperature measurements suggest that the altitude where snow occurs (above the snow line) has probably risen in mountainous regions of South America. {4.2}

Permafrost and seasonally frozen ground in most regions display large changes in recent decades. Changes in permafrost conditions can affect river runoff, water supply, carbon exchange and landscape stability, and can cause damage to infrastructure. Temperature increases at the top of the permafrost layer of up to 3°C since the 1980s have been reported. Permafrost warming has also been observed with variable magnitude in the Canadian Arctic, Siberia, the Tibetan Plateau and Europe. The permafrost base is thawing at a rate ranging from 0.04 m yr^{-1} in Alaska to 0.02 m yr^{-1} on the Tibetan Plateau. {4.7}

The maximum area covered by seasonally frozen ground decreased by about 7% in the NH over the

[6] Precipitation and temperature are combined in the Palmer Drought Severity Index (PDSI), considered in this report as one measure of drought. The PDSI does not include variables such as wind speed, solar radiation, cloudiness and water vapour but is a superior measure to precipitation alone.

Box TS.3: Ice Sheet Dynamics and Stability

Ice sheets are thick, broad masses of ice formed mainly from compaction of snow. They spread under their own weight, transferring mass towards their margins where it is lost primarily by runoff of surface melt water or by calving of icebergs into marginal seas or lakes. Ice sheets flow by deformation within the ice or melt water-lubricated sliding over materials beneath. Rapid basal motion requires that the basal temperature be raised to the melting point by heat from the Earth's interior, delivered by melt water transport, or from the 'friction' of ice motion. Sliding velocities under a given gravitational stress can differ by several orders of magnitude, depending on the presence or absence of deformable sediment, the roughness of the substrate and the supply and distribution of water. Basal conditions are generally poorly characterised, introducing important uncertainties to the understanding of ice sheet stability. {4.6}

Ice flow is often channelled into fast-moving ice streams (that flow between slower-moving ice walls) or outlet glaciers (with rock walls). Enhanced flow in ice streams arises either from higher gravitational stress linked to thicker ice in bedrock troughs, or from increased basal lubrication. {4.6}

Ice discharged across the coast often remains attached to the ice sheet to become a floating ice shelf. An ice shelf moves forward, spreading and thinning under its own weight, and fed by snowfall on its surface and ice input from the ice sheet. Friction at ice shelf sides and over local shoals slows the flow of the ice shelf and thus the discharge from the ice sheet. An ice shelf loses mass by calving icebergs from the front and by basal melting into the ocean cavity beneath. Studies suggest an ocean warming of 1°C could increase ice shelf basal melt by 10 m yr^{-1}, but inadequate knowledge of the largely inaccessible ice shelf cavities restricts the accuracy of such estimates. {4.6}

The palaeo-record of previous ice ages indicates that ice sheets shrink in response to warming and grow in response to cooling, and that shrinkage can be far faster than growth. The volumes of the Greenland and Antarctic Ice Sheets are equivalent to approximately 7 m and 57 m of sea level rise, respectively. Palaeoclimatic data indicate that substantial melting of one or both ice sheets has likely occurred in the past. However, ice core data show that neither ice sheet was completely removed during warm periods of at least the past million years. Ice sheets can respond to environmental forcing over very long time scales, implying that commitments to future changes may result from current warming. For example, a surface warming may take more than 10,000 years to penetrate to the bed and change temperatures there. Ice velocity over most of an ice sheet changes slowly in response to changes in the ice sheet shape or surface temperature, but large velocity changes may occur rapidly in ice streams and outlet glaciers in response to changing basal conditions, penetration of surface melt water to the bed or changes in the ice shelves into which they flow. {4.6, 6.4}

Models currently configured for long integrations remain most reliable in their treatment of surface accumulation and ablation, as for the TAR, but do not include full treatments of ice dynamics; thus, analyses of past changes or future projections using such models may underestimate ice flow contributions to sea level rise, but the magnitude of such an effect is unknown. {8.2}

latter half of the 20th century, with a decrease in spring of up to 15%. Its maximum depth has decreased by about 0.3 m in Eurasia since the mid-20th century. In addition, maximum seasonal thaw depth increased by about 0.2 m in the Russian Arctic from 1956 to 1990. {4.7}

On average, the general trend in NH river and lake ice over the past 150 years indicates that the freeze-up date has become later at an average rate of 5.8 ± 1.9 days per century, while the breakup date has occurred earlier, at a rate of 6.5 ± 1.4 days per century. However, considerable spatial variability has also been observed, with some regions showing trends of opposite sign. {4.3}

Annual average arctic sea ice extent has shrunk by about 2.7 ± 0.6% per decade since 1978 based upon satellite observations (see Figure TS.13). The decline in summer extent is larger than in winter extent, with the summer minimum declining at a rate of about 7.4 ± 2.4% per decade. Other data indicate that the summer decline began around 1970. Similar observations in the Antarctic reveal larger interannual variability but no consistent trends during the period of satellite observations. In contrast to changes in continental ice such as ice sheets and glaciers, changes in sea ice do not directly contribute to sea level change (because this ice is already floating), but can contribute to salinity changes through input of freshwater. {4.4}

During the 20th century, glaciers and ice caps have experienced widespread mass losses and have contributed to sea level rise. Mass loss of glaciers and ice caps (excluding those around the ice sheets of Greenland and Antarctica) is estimated to be 0.50 ± 0.18 mm yr^{-1} in sea level equivalent (SLE) between 1961 and 2003, and 0.77 ± 0.22 mm yr^{-1} SLE between 1991 and 2003. The late 20th-century glacier wastage *likely* has been a response to post-1970 warming. {4.5}

Recent observations show evidence for rapid changes in ice flow in some regions, contributing to sea level rise and suggesting that the dynamics of ice

motion may be a key factor in future responses of ice shelves, coastal glaciers and ice sheets to climate change. Thinning or loss of ice shelves in some near-coastal regions of Greenland, the Antarctic Peninsula and West Antarctica has been associated with accelerated flow of nearby glaciers and ice streams, suggesting that ice shelves (including short ice shelves of kilometres or tens of kilometres in length) could play a larger role in stabilising or restraining ice motion than previously thought. Both oceanic and atmospheric temperatures appear to contribute to the observed changes. Large summer warming in the Antarctic Peninsula region *very likely* played a role in the subsequent rapid breakup of the Larsen B Ice Shelf in 2002 by increasing summer melt water, which drained into crevasses and wedged them open. Models do not accurately capture all of the physical processes that appear to be involved in observed iceberg calving (as in the breakup of Larsen B). {4.6}

Changes in Snow Cover

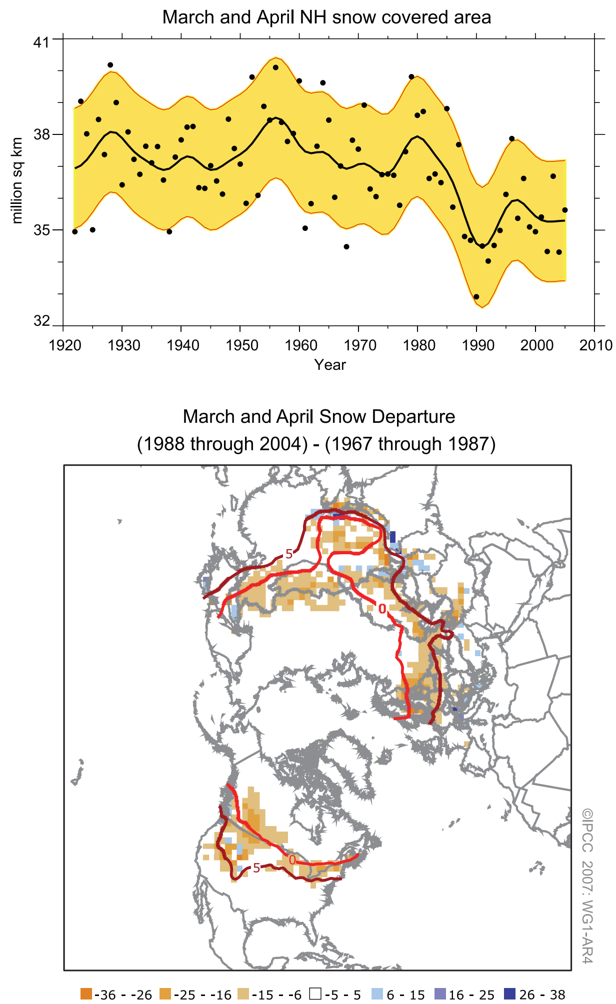


Figure TS.12. *(Top) Northern Hemisphere March-April snow-covered area from a station-derived snow cover index (prior to 1972) and from satellite data (during and after 1972). The smooth curve shows decadal variations (see Appendix 3.A) with the 5 to 95% data range shaded in yellow. (Bottom) Differences in the distribution of March-April snow cover between earlier (1967–1987) and later (1988–2004) portions of the satellite era (expressed in percent coverage). Tan colours show areas where snow cover has declined. Red curves show the 0°C and 5°C isotherms averaged for March-April 1967 to 2004, from the Climatic Research Unit (CRU) gridded land surface temperature version 2 (CRUTEM2v) data. The greatest decline generally tracks the 0°C and 5°C isotherms, reflecting the strong feedback between snow and temperature. {Figures 4.2, 4.3}*

Changes in Sea Ice Extent

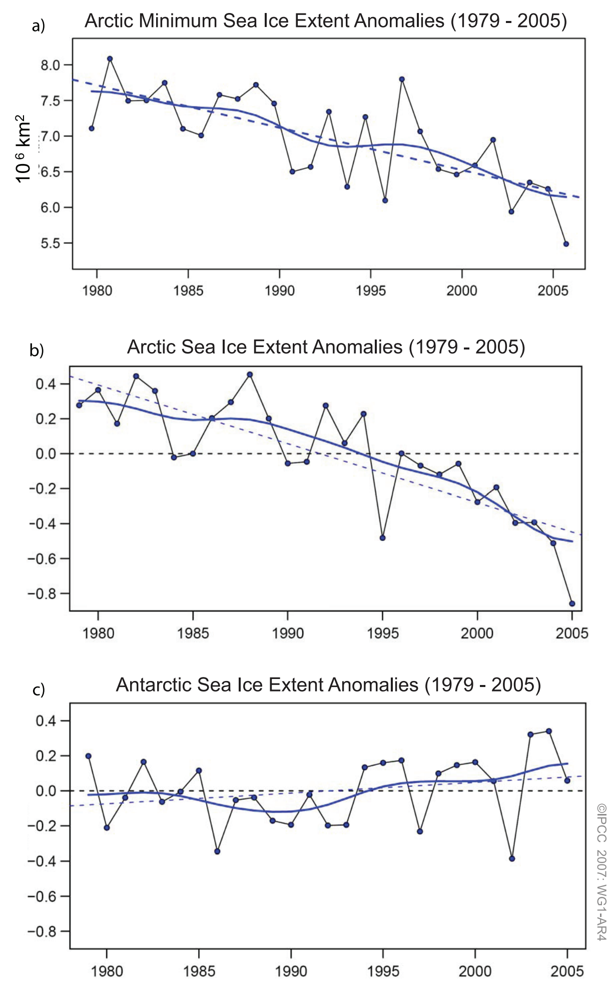


Figure TS.13. *(a) Arctic minimum sea ice extent; (b) arctic sea ice extent anomalies; and (c) antarctic sea ice extent anomalies all for the period 1979 to 2005. Symbols indicate annual values while the smooth blue curves show decadal variations (see Appendix 3.A). The dashed lines indicate the linear trends. (a) Results show a linear trend of –60 ± 20 x 10^3 km^2 yr^{-1}, or approximately -7.4% per decade. (b) The linear trend is –33 ± 7.4 x 10^3 km^2 yr^{-1} (equivalent to approximately –2.7% per decade) and is significant at the 95% confidence level. (c) Antarctic results show a small positive trend of 5.6 ± 9.2 x 10^3 km^2 yr^{-1}, which is not statistically significant. {Figures 4.8 and 4.9}*

The Greenland and Antarctic Ice Sheets taken together have *very likely* contributed to the sea level rise of the past decade. It is *very likely* that the Greenland Ice Sheet shrunk from 1993 to 2003, with thickening in central regions more than offset by increased melting in coastal regions. Whether the ice sheets have been growing or shrinking over time scales of longer than a decade is not well established from observations. Lack of agreement between techniques and the small number of estimates preclude assignment of best estimates or statistically rigorous error bounds for changes in ice sheet mass balances. However, acceleration of outlet glaciers drains ice from the interior and has been observed in both ice sheets (see Figure TS.14). Assessment of the data and techniques suggests a mass balance for the Greenland Ice Sheet of –50 to –100 Gt yr^{-1} (shrinkage contributing to raising global sea level by 0.14 to 0.28 mm yr^{-1}) during 1993 to 2003, with even larger losses in 2005. There are greater uncertainties for earlier time periods and for Antarctica. The estimated range in mass balance for the Greenland Ice Sheet over the period 1961 to 2003 is between growth of 25 Gt yr^{-1} and shrinkage by 60 Gt yr^{-1} (–0.07 to +0.17 mm yr^{-1} SLE). Assessment of all the data yields an estimate for the overall Antarctic Ice Sheet mass balance ranging from growth of 100 Gt yr^{-1} to shrinkage of 200 Gt yr^{-1} (–0.27 to +0.56 mm yr^{-1} SLE) from 1961 to 2003, and from +50 to –200 Gt yr^{-1} (–0.14 to +0.55 mm yr^{-1} SLE) from 1993 to 2003. The recent changes in ice flow are *likely* to be sufficient to explain much or all of the estimated antarctic mass imbalance, with recent changes in ice flow, snowfall and melt water runoff sufficient to explain the mass imbalance of Greenland. {4.6, 4.8}

Rates of Observed Surface Elevation Change

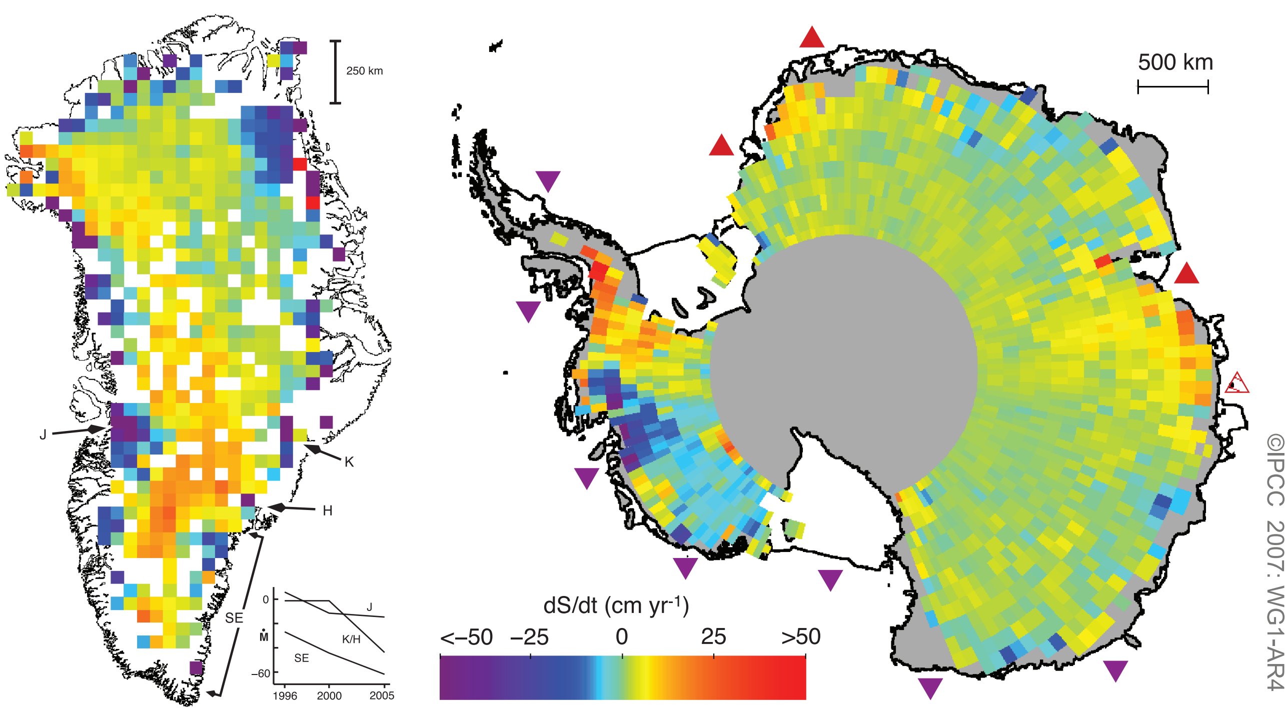


Figure TS.14. *Rates of observed recent surface elevation change for Greenland (left; 1989–2005) and Antarctica (right; 1992–2005). Red hues indicate a rising surface and blue hues a falling surface, which typically indicate an increase or loss in ice mass at a site, although changes over time in bedrock elevation and in near-surface density can be important. For Greenland, the rapidly thinning outlet glaciers Jakobshavn (J), Kangerdlugssuaq (K), Helheim (H) and areas along the southeast coast (SE) are shown, together with their estimated mass balance vs. time (with K and H combined, in Gt yr^{-1}, with negative values indicating loss of mass from the ice sheet to the ocean). For Antarctica, ice shelves estimated to be thickening or thinning by more than 30 cm yr^{-1} are shown by point-down purple triangles (thinning) and point-up red triangles (thickening) plotted just seaward of the relevant ice shelves. {Figures 4.17 and 4.19}*

TS.3.3 Changes in the Ocean: Instrumental Record

The ocean plays an important role in climate and climate change. The ocean is influenced by mass, energy and momentum exchanges with the atmosphere. Its heat capacity is about 1000 times larger than that of the atmosphere and the ocean's net heat uptake is therefore many times greater than that of the atmosphere (see Figure TS.15). Global observations of the heat taken up by the ocean can now be shown to be a definitive test of changes in the global energy budget. Changes in the amount of energy taken up by the upper layers of the ocean also play a crucial role for climate variations on seasonal to interannual time scales, such as El Niño. Changes in the transport of heat and SSTs have important effects upon many regional climates worldwide. Life in the sea is dependent on the biogeochemical status of the ocean and is affected by changes in its physical state and circulation. Changes in ocean biogeochemistry can also feed back into the climate system, for example, through changes in uptake or release of radiatively active gases such as CO_2. {5.1, 7.3}

Energy Content in the Climate System

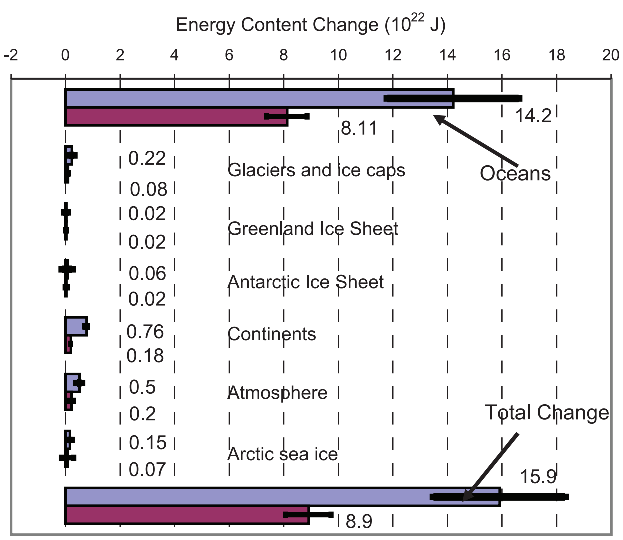


Figure TS.15. *Energy content changes in different components of the Earth system for two periods (1961–2003 and 1993–2003). Blue bars are for 1961 to 2003; burgundy bars are for 1993 to 2003. Positive energy content change means an increase in stored energy (i.e., heat content in oceans, latent heat from reduced ice or sea ice volumes, heat content in the continents excluding latent heat from permafrost changes, and latent and sensible heat and potential and kinetic energy in the atmosphere). All error estimates are 90% confidence intervals. No estimate of confidence is available for the continental heat gain. Some of the results have been scaled from published results for the two respective periods. {Figure 5.4}*

Global mean sea level variations are driven in part by changes in density, through thermal expansion or contraction of the ocean's volume. Local changes in sea level also have a density-related component due to temperature and salinity changes. In addition, exchange of water between oceans and other reservoirs (e.g., ice sheets, mountain glaciers, land water reservoirs and the atmosphere) can change the ocean's mass and hence contribute to changes in sea level. Sea level change is not geographically uniform because processes such as ocean circulation changes are not uniform across the globe (see Box TS.4). {5.5}

Oceanic variables can be useful for climate change detection, in particular temperature and salinity changes below the surface mixed layer where the variability is smaller and signal-to-noise ratio is higher. Observations analysed since the TAR have provided new evidence for changes in global ocean heat content and salinity, sea level, thermal expansion contributions to sea level rise, water mass evolution and biogeochemical cycles. {5.5}

TS.3.3.1 Changes in Ocean Heat Content and Circulation

The world ocean has warmed since 1955, accounting over this period for more than 80% of the changes in the energy content of the Earth's climate system. A total of 7.9 million vertical profiles of ocean temperature allows construction of improved global time series (see Figure TS.16). Analyses of the global oceanic heat budget have been replicated by several independent analysts and are robust to the method used. Data coverage limitations require averaging over decades for the deep ocean and observed decadal variability in the global heat content is not fully understood. However, inadequacies in the distribution of data (particularly coverage in the Southern Ocean and South Pacific) could contribute to the apparent decadal variations in heat content. During the period 1961 to 2003, the 0 to 3000 m ocean layer has taken up about 14.1×10^{22} J, equivalent to an average heating rate of 0.2 W m^{-2} (per unit area of the Earth's surface). During 1993 to 2003, the corresponding rate of warming in the shallower 0 to 700 m ocean layer was higher, about 0.5 ± 0.18 W m^{-2}. Relative to 1961 to 2003, the period 1993 to 2003 had high rates of warming but in 2004 and 2005 there has been some cooling compared to 2003. {5.1–5.3}

Warming is widespread over the upper 700 m of the global ocean. The Atlantic has warmed south of 45°N. The warming is penetrating deeper in the Atlantic Ocean Basin than in the Pacific, Indian and Southern Oceans, due to the

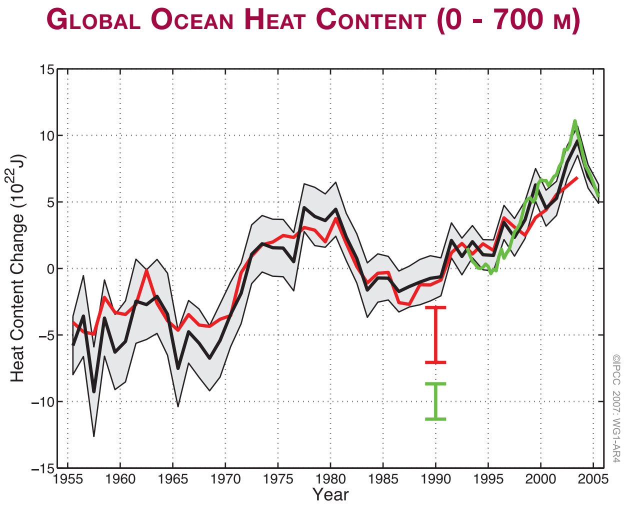


Figure TS.16. *Time series of global ocean heat content (10^{22} J) for the 0 to 700 m layer. The three coloured lines are independent analyses of the oceanographic data. The black and red curves denote the deviation from their 1961 to 1990 average and the shorter green curve denotes the deviation from the average of the black curve for the period 1993 to 2003. The 90% uncertainty range for the black curve is indicated by the grey shading and for the other two curves by the error bars. {Figure 5.1}*

deep overturning circulation cell that occurs in the North Atlantic. The SH deep overturning circulation shows little evidence of change based on available data. However, the upper layers of the Southern Ocean contribute strongly to the overall warming. At least two seas at subtropical latitudes (Mediterranean and Japan/East China Sea) are warming. While the global trend is one of warming, significant decadal variations have been observed in the global time series, and there are large regions where the oceans are cooling. Parts of the North Atlantic, North Pacific and equatorial Pacific have cooled over the last 50 years. The changes in the Pacific Ocean show ENSO-like spatial patterns linked in part to the PDO. {5.2, 5.3}

Parts of the Atlantic meridional overturning circulation exhibit considerable decadal variability, but data do not support a coherent trend in the overturning circulation. {5.3}

TS.3.3.2 Changes in Ocean Biogeochemistry and Salinity

The uptake of anthropogenic carbon since 1750 has led to the ocean becoming more acidic, with an average decrease in surface pH of 0.1 units.[7] Uptake of CO_2 by the ocean changes its chemical equilibrium. Dissolved CO_2 forms a weak acid, so as dissolved CO_2 increases, pH decreases (i.e., the ocean becomes more acidic). The overall pH change is computed from estimates of anthropogenic carbon uptake and simple ocean models. Direct observations of pH at available stations for the last 20 years also show trends of decreasing pH, at a rate of about 0.02 pH units per decade. Decreasing ocean pH decreases the depth below which calcium carbonate dissolves and increases the volume of the ocean that is undersaturated with respect to the minerals aragonite (a meta-stable form of calcium carbonate) and calcite, which are used by marine organisms to build their shells. Decreasing surface ocean pH and rising surface temperatures also act to reduce the ocean buffer capacity for CO_2 and the rate at which the ocean can take up excess atmospheric CO_2. {5.4, 7.3}

The oxygen concentration of the ventilated thermocline (about 100 to 1000 m) decreased in most ocean basins between 1970 and 1995. These changes may reflect a reduced rate of ventilation linked to upper-level warming and/or changes in biological activity. {5.4}

There is now widespread evidence for changes in ocean salinity at gyre and basin scales in the past half century (see Figure TS.17) with the near-surface waters in the more evaporative regions increasing in salinity in almost all ocean basins. These changes in salinity imply changes in the hydrological cycle over the oceans. In the high-latitude regions in both hemispheres, the surface waters show an overall freshening consistent with these regions having greater precipitation, although higher runoff, ice melting, advection and changes in the meridional overturning circulation may also contribute. The subtropical latitudes in both hemispheres are characterised by an increase in salinity in the upper 500 m. The patterns are consistent with a change in the Earth's hydrological cycle, in particular with changes in precipitation and inferred larger water transport in the atmosphere from low latitudes to high latitudes and from the Atlantic to the Pacific. {5.2}

TS.3.3.3 Changes in Sea Level

Over the 1961 to 2003 period, the average rate of global mean sea level rise is estimated from tide gauge data to be 1.8 ± 0.5 mm yr^{-1} (see Figure TS.18). For the purpose of examining the sea level budget, best estimates and 5 to 95% confidence intervals are provided for all land ice contributions. The average

[7] Acidity is a measure of the concentration of H^+ ions and is reported in pH units, where pH = –log(H^+). A pH decrease of 1 unit means a 10-fold increase in the concentration of H^+, or acidity.

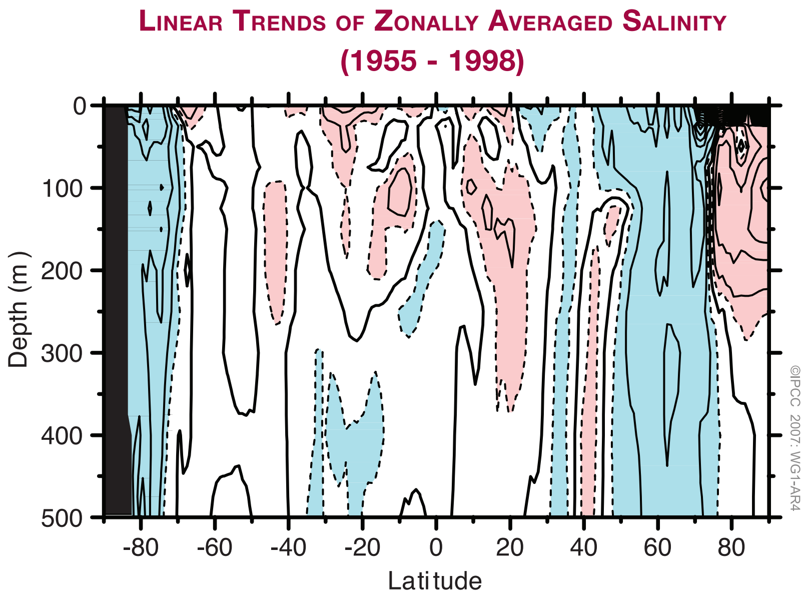


Figure TS.17. *Linear trends (1955–1998) of zonally averaged salinity (Practical Salinity Scale) for the World Ocean. The contour interval is 0.01 per decade and dashed contours are ±0.005 per decade. The dark, solid line is the zero contour. Red shading indicates values equal to or greater than 0.005 per decade and blue shading indicates values equal to or less than –0.005 per decade. {Figure 5.5}*

thermal expansion contribution to sea level rise for this period was 0.42 ± 0.12 mm yr^{-1}, with significant decadal variations, while the contribution from glaciers, ice caps and ice sheets is estimated to have been 0.7 ± 0.5 mm yr^{-1} (see Table TS.3). The sum of these estimated climate-related contributions for about the past four decades thus amounts to 1.1 ± 0.5 mm yr^{-1}, which is less than the best estimate from the tide gauge observations (similar to the discrepancy noted in the TAR). Therefore, the sea level budget for 1961 to 2003 has not been closed satisfactorily. {4.8, 5.5}

The global average rate of sea level rise measured by TOPEX/Poseidon satellite altimetry during 1993 to 2003 is 3.1 ± 0.7 mm yr^{-1}. This observed rate for the recent period is close to the estimated total of 2.8 ± 0.7 mm yr^{-1} for the climate-related contributions due to thermal expansion (1.6 ± 0.5 mm yr^{-1}) and changes in land ice (1.2 ± 0.4 mm yr^{-1}). Hence, the understanding of the budget has improved significantly for this recent period, with the climate contributions constituting the main factors in the sea level budget (which is closed to within known errors). Whether the faster rate for 1993 to 2003 compared to 1961 to 2003 reflects decadal variability or an increase in the longer-term trend is unclear. The tide gauge record indicates that faster rates similar to that observed in 1993 to 2003 have occurred in other decades since 1950. {5.5, 9.5}

There is *high confidence* that the rate of sea level rise accelerated between the mid-19th and the mid-20th centuries based upon tide gauge and geological data. A recent reconstruction of sea level change back to 1870 using the best available tide records provides high confidence that the rate of sea level rise accelerated over the period 1870 to 2000. Geological observations indicate that during the previous 2000 years, sea level change was small, with average rates in the range 0.0 to 0.2 mm yr^{-1}. The use of proxy sea level data from archaeological sources is well established in the Mediterranean and indicates that oscillations in sea level from about AD 1 to AD 1900 did not exceed ±0.25 m. The available evidence indicates that the onset of modern sea level rise started between the mid-19th and mid-20th centuries. {5.5}

Precise satellite measurements since 1993 now provide unambiguous evidence of regional variability of sea level change. In some regions, rates of rise during this period are up to several times the global mean,

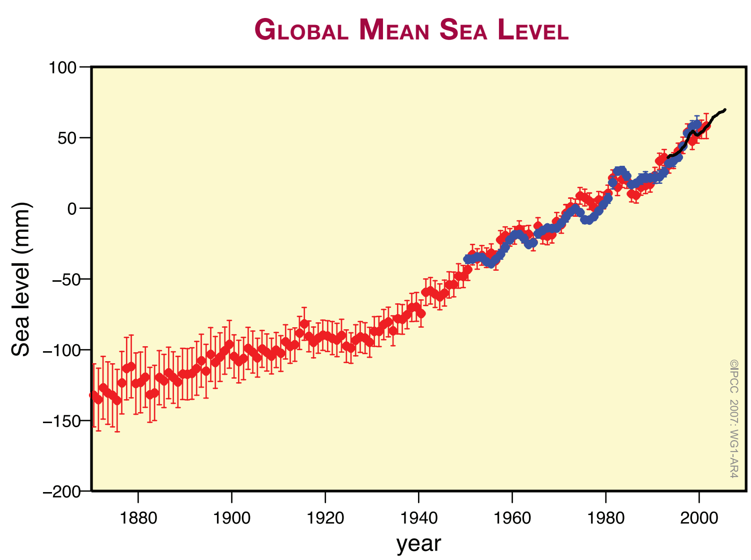


Figure TS.18. *Annual averages of the global mean sea level based on reconstructed sea level fields since 1870 (red), tide gauge measurements since 1950 (blue) and satellite altimetry since 1992 (black). Units are in mm relative to the average for 1961 to 1990. Error bars are 90% confidence intervals. {Figure 5.13}*

Table TS.3. *Contributions to sea level rise based upon observations (left columns) compared to models used in this assessment (right columns; see Section 9.5 and Appendix 10.A for details). Values are presented for 1993 to 2003 and for the last four decades, including observed totals. {Adapted from Tables 5.3 and 9.2}*

	Sea Level Rise (mm yr^{-1})			
	1961–2003		1993–2003	
Sources of Sea Level Rise	**Observed**	**Modelled**	**Observed**	**Modelled**
Thermal expansion	0.42 ± 0.12	0.5 ± 0.2	1.6 ± 0.5	1.5 ± 0.7
Glaciers and ice caps	0.50 ± 0.18	0.5 ± 0.2	0.77 ± 0.22	0.7 ± 0.3
Greenland Ice Sheet	0.05 ± 0.12[a]		0.21 ± 0.07[a]	
Antarctic Ice Sheet	0.14 ± 0.41[a]		0.21 ± 0.35[a]	
Sum of individual climate contributions to sea level rise	1.1 ± 0.5	1.2 ± 0.5	2.8 ± 0.7	2.6 ± 0.8
Observed total sea level rise	1.8 ± 0.5 (tide gauges)		3.1 ± 0.7 (satellite altimeter)	
Difference (Observed total minus the sum of observed climate contributions)	0.7 ± 0.7		0.3 ± 1.0	

Notes:
[a] prescribed based upon observations (see Section 9.5)

while in other regions sea level is falling. The largest sea level rise since 1992 has taken place in the western Pacific and eastern Indian Oceans (see Figure TS.19). Nearly all of the Atlantic Ocean shows sea level rise during the past decade, while sea level in the eastern Pacific and western Indian Oceans has been falling. These temporal and spatial variations in regional sea level rise are influenced in part by patterns of coupled ocean-atmosphere variability, including ENSO and the NAO. The pattern of observed sea level change since 1992 is similar to the thermal expansion computed from ocean temperature changes, but different from the thermal expansion pattern of the last 50 years, indicating the importance of regional decadal variability. {5.5}

Observations suggest increases in extreme high water at a broad range of sites worldwide since 1975. Longer records are limited in space and under-sampled in time, so a global analysis over the entire 20th century is not feasible. In many locations, the secular changes in extremes were similar to those in mean sea level. At others, changes in atmospheric conditions such as storminess were more important in determining long-term trends. Interannual variability in high water extremes was positively correlated with regional mean sea level, as well as to indices of regional climate such as ENSO in the Pacific and NAO in the Atlantic. {5.5}

Sea Level Change Patterns

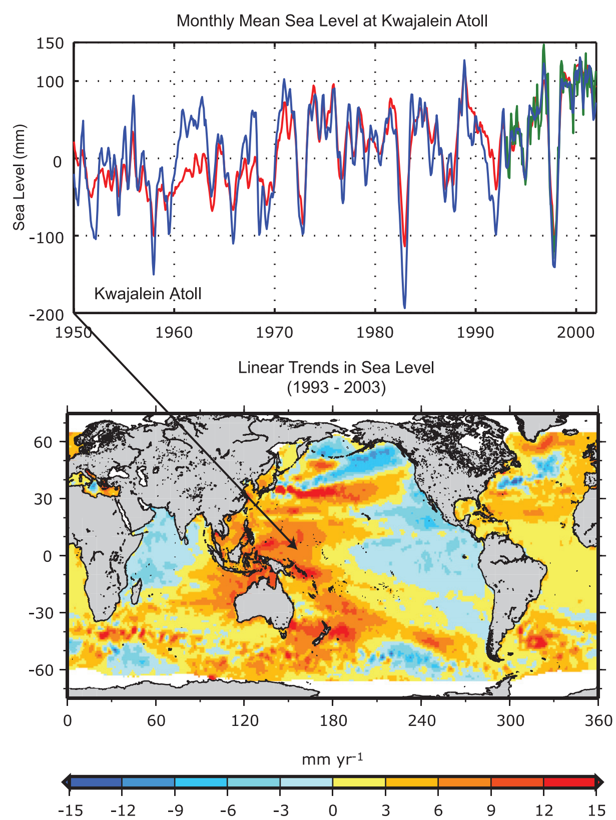


Figure TS.19. *(Top) Monthly mean sea level (mm) curve for 1950 to 2000 at Kwajalein (8°44'N, 167°44'E). The observed sea level (from tide gauge measurements) is in blue, the reconstructed sea level in red and the satellite altimetry record in green. Annual and semiannual signals have been removed from each time series and the tide gauge data have been smoothed. (Bottom) Geographic distribution of short-term linear trends in mean sea level for 1993 to 2003 (mm yr^{-1}) based on TOPEX/Poseidon satellite altimetry. {Figures 5.15 and 5.18}*

Box TS.4: Sea Level

The level of the sea at the shoreline is determined by many factors that operate over a great range of temporal scales: hours to days (tides and weather), years to millennia (climate), and longer. The land itself can rise and fall and such regional land movements need to be accounted for when using tide gauge measurements for evaluating the effect of oceanic climate change on coastal sea level. Coastal tide gauges indicate that global average sea level rose during the 20th century. Since the early 1990s, sea level has also been observed continuously by satellites with near-global coverage. Satellite and tide gauge data agree at a wide range of spatial scales and show that global average sea level has continued to rise during this period. Sea level changes show geographical variation because of several factors, including the distributions of changes in ocean temperature, salinity, winds and ocean circulation. Regional sea level is affected by climate variability on shorter time scales, for instance associated with El Niño and the NAO, leading to regional interannual variations which can be much greater or weaker than the global trend.

Based on ocean temperature observations, the thermal expansion of seawater as it warms has contributed substantially to sea level rise in recent decades. Climate models are consistent with the ocean observations and indicate that thermal expansion is expected to continue to contribute to sea level rise over the next 100 years. Since deep ocean temperatures change only slowly, thermal expansion would continue for many centuries even if atmospheric concentrations of greenhouse gases were stabilised.

Global average sea level also rises or falls when water is transferred from land to ocean or vice versa. Some human activities can contribute to sea level change, especially by the extraction of groundwater and construction of reservoirs. However, the major land store of freshwater is the water frozen in glaciers, ice caps and ice sheets. Sea level was more than 100 m lower during the glacial periods because of the ice sheets covering large parts of the NH continents. The present-day retreat of glaciers and ice caps is making a substantial contribution to sea level rise. This is expected to continue during the next 100 years. Their contribution should decrease in subsequent centuries as this store of freshwater diminishes.

The Greenland and Antarctic Ice Sheets contain much more ice and could make large contributions over many centuries. In recent years the Greenland Ice Sheet has experienced greater melting, which is projected to increase further. In a warmer climate, models suggest that the ice sheets could accumulate more snowfall, tending to lower sea level. However, in recent years any such tendency has probably been outweighed by accelerated ice flow and greater discharge observed in some marginal areas of the ice sheets. The processes of accelerated ice flow are not yet completely understood but could result in overall net sea level rise from ice sheets in the future.

The greatest climate- and weather-related impacts of sea level are due to extremes on time scales of days and hours, associated with tropical cyclones and mid-latitude storms. Low atmospheric pressure and high winds produce large local sea level excursions called 'storm surges', which are especially serious when they coincide with high tide. Changes in the frequency of occurrence of these extreme sea levels are affected both by changes in mean sea level and in the meteorological phenomena causing the extremes. {5.5}

TS.3.4 Consistency Among Observations

In this section, variability and trends within and across different climate variables including the atmosphere, cryosphere and oceans are examined for consistency based upon conceptual understanding of physical relationships between the variables. For example, increases in temperature will enhance the moisture-holding capacity of the atmosphere. Changes in temperature and/or precipitation should be consistent with those evident in glaciers. Consistency between independent observations using different techniques and variables provides a key test of understanding, and hence enhances confidence. {3.9}

Changes in the atmosphere, cryosphere and ocean show unequivocally that the world is warming. {3.2, 3.9, 4.2, 4.4–4.8, 5.2, 5.5}

Both land surface air temperatures and SSTs show warming. In both hemispheres, land regions have warmed at a faster rate than the oceans in the past few decades, consistent with the much greater thermal inertia of the oceans. {3.2}

The warming of the climate is consistent with observed increases in the number of daily warm extremes, reductions in the number of daily cold extremes and reductions in the number of frost days at mid-latitudes. {3.2, 3.8}

Surface air temperature trends since 1979 are now consistent with those at higher altitudes. It is *likely* that there is slightly greater warming in the troposphere than at the surface, and a higher tropopause, consistent with expectations from basic physical processes and observed increases in greenhouse gases together with depletion of stratospheric ozone. {3.4, 9.4}

Changes in temperature are broadly consistent with the observed nearly worldwide shrinkage of the cryosphere. There have been widespread reductions in mountain glacier mass and extent. Changes in climate consistent with warming are also indicated by decreases in snow cover, snow depth, arctic sea ice extent, permafrost thickness and temperature, the extent of seasonally frozen ground and the length of the freeze season of river and lake ice. {3.2, 3.9, 4.2–4.5, 4.7}

Observations of sea level rise since 1993 are consistent with observed changes in ocean heat content and the cryosphere. Sea level rose by 3.1 ± 0.7 mm yr^{-1} from 1993 to 2003, the period of availability of global altimetry measurements. During this time, a near balance was observed between observed total sea level rise and contributions from glacier, ice cap and ice sheet retreat together with increases in ocean heat content and associated ocean expansion. This balance gives increased

Table TS.4. *Recent trends, assessment of human influence on trends, and projections of extreme weather and climate events for which there is evidence of an observed late 20th-century trend. An asterisk in the column headed 'D' indicates that formal detection and attribution studies were used, along with expert judgement, to assess the likelihood of a discernible human influence. Where this is not available, assessments of likelihood of human influence are based on attribution results for changes in the mean of a variable or changes in physically related variables and/or on the qualitative similarity of observed and simulated changes, combined with expert judgement. {3.8, 5.5, 9.7, 11.2–11.9; Tables 3.7, 3.8, 9.4}*

Phenomenon[a] and direction of trend	Likelihood that trend occurred in late 20th century (typically post-1960)	Likelihood of a human contribution to observed trend	D	Likelihood of future trend based on projections for 21st century using SRES[b] scenarios
Warmer and fewer cold days and nights over most land areas	*Very likely*[c]	*Likely*[e]	*	*Virtually certain*[e]
Warmer and more frequent hot days and nights over most land areas	*Very likely*[d]	*Likely* (nights) [e]	*	*Virtually certain*[e]
Warm spells / heat waves: Frequency increases over most land areas	*Likely*	*More likely than not*		*Very likely*
Heavy precipitation events. Frequency (or proportion of total rainfall from heavy falls) increases over most areas	*Likely*	*More likely than not*		*Very likely*
Area affected by droughts increases	*Likely* in many regions since 1970s	*More likely than not*	*	*Likely*
Intense tropical cyclone activity increases	*Likely* in some regions since 1970	*More likely than not*		*Likely*
Increased incidence of extreme high sea level (excludes tsunamis)[f]	*Likely*	*More likely than not* [g]		*Likely* [h]

Notes:
[a] See Table 3.7 for further details regarding definitions.
[b] SRES refers to the IPCC Special Report on Emission Scenarios. The SRES scenario families and illustrative cases are summarised in a box at the end of the Summary for Policymakers.
[c] Decreased frequency of cold days and nights (coldest 10%)
[d] Increased frequency of hot days and nights (hottest 10%)
[e] Warming of the most extreme days/nights each year
[f] Extreme high sea level depends on average sea level and on regional weather systems. It is defined here as the highest 1% of hourly values of observed sea level at a station for a given reference period.
[g] Changes in observed extreme high sea level closely follow the changes in average sea level {5.5.2.6}. It is *very likely* that anthropogenic activity contributed to a rise in average sea level. {9.5.2}
[h] In all scenarios, the projected global average sea level at 2100 is higher than in the reference period {10.6}. The effect of changes in regional weather systems on sea level extremes has not been assessed.

confidence that the observed sea level rise is a strong indicator of warming. However, the sea level budget is not balanced for the longer period 1961 to 2003. {5.5, 3.9}

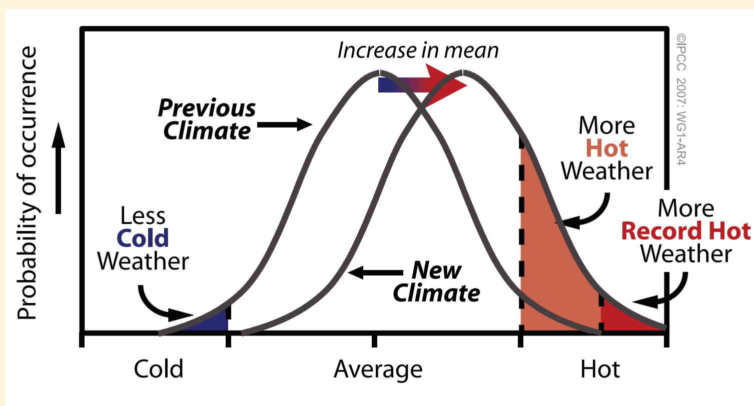
Observations are consistent with physical understanding regarding the expected linkage between water vapour and temperature, and with intensification of precipitation events in a warmer world. Column and upper-tropospheric water vapour have increased, providing important support for the hypothesis of simple physical models that specific humidity increases in a warming world and represents an important positive feedback to climate change. Consistent with rising amounts of water vapour in the atmosphere, there are widespread increases in the numbers of heavy precipitation events and increased likelihood of flooding events in many land regions, even those where there has been a reduction in total precipitation. Observations of changes in ocean salinity independently support the view

Box TS.5: Extreme Weather Events

People affected by an extreme weather event (e.g., the extremely hot summer in Europe in 2003, or the heavy rainfall in Mumbai, India in July 2005) often ask whether human influences on the climate are responsible for the event. A wide range of extreme weather events is expected in most regions even with an unchanging climate, so it is difficult to attribute any individual event to a change in the climate. In most regions, instrumental records of variability typically extend only over about 150 years, so there is limited information to characterise how extreme rare climatic events could be. Further, several factors usually need to combine to produce an extreme event, so linking a particular extreme event to a single, specific cause is problematic. In some cases, it may be possible to estimate the anthropogenic contribution to such changes in the probability of occurrence of extremes.

However, simple statistical reasoning indicates that substantial changes in the frequency of extreme events (and in the maximum feasible extreme, e.g., the maximum possible 24-hour rainfall at a specific location) can result from a relatively small shift of the distribution of a weather or climate variable.

Extremes are the infrequent events at the high and low end of the range of values of a particular variable. The probability of occurrence of values in this range is called a probability distribution function (PDF) that for some variables is shaped similarly to a 'Normal' or 'Gaussian' curve (the familiar 'bell' curve). Box TS.5, Figure 1 shows a schematic of a such a PDF and illustrates the effect a small shift (corresponding to a small change in the average or centre of the distribution) can have on the frequency of extremes at either end of the distribution. An increase in the frequency of one extreme (e.g., the number of hot days) will often be accompanied by a decline in the opposite extreme (in this case the number of cold days such as frosts). Changes in the variability or shape of the distribution can complicate this simple picture.



Box TS.5, Figure 1. *Schematic showing the effect on extreme temperatures when the mean temperature increases, for a normal temperature distribution.*

The IPCC Second Assessment Report noted that data and analyses of extremes related to climate change were sparse. By the time of the TAR, improved monitoring and data for changes in extremes was available, and climate models were being analysed to provide projections of extremes. Since the TAR, the observational basis of analyses of extremes has increased substantially, so that some extremes have now been examined over most land areas (e.g., daily temperature and rainfall extremes). More models have been used in the simulation and projection of extremes, and multiple integrations of models with different starting conditions (ensembles) now provide more robust information about PDFs and extremes. Since the TAR, some climate change detection and attribution studies focussed on changes in the global statistics of extremes have become available (Table TS.4). For some extremes (e.g., tropical cyclone intensity), there are still data concerns and/or inadequate models. Some assessments still rely on simple reasoning about how extremes might be expected to change with global warming (e.g., warming could be expected to lead to more heat waves). Others rely on qualitative similarity between observed and simulated changes. The assessed likelihood of anthropogenic contributions to trends is lower for variables where the assessment is based on indirect evidence.

that the Earth's hydrologic cycle has changed, in a manner consistent with observations showing greater precipitation and river runoff outside the tropics and subtropics, and increased transfer of freshwater from the ocean to the atmosphere at lower latitudes. {3.3, 3.4, 3.9, 5.2}

Although precipitation has increased in many areas of the globe, the area under drought has also increased. Drought duration and intensity has also increased. While regional droughts have occurred in the past, the widespread spatial extent of current droughts is broadly consistent with expected changes in the hydrologic cycle under warming. Water vapour increases with increasing global temperature, due to increased evaporation where surface moisture is available, and this tends to increase precipitation. However, increased continental temperatures are expected to lead to greater evaporation and drying, which is particularly important in dry regions where surface moisture is limited. Changes in snowpack, snow cover and in atmospheric circulation patterns and storm tracks can also reduce available seasonal moisture, and contribute to droughts. Changes in SSTs and associated changes in the atmospheric circulation and precipitation have contributed to changes in drought, particularly at low latitudes. The result is that drought has become more common, especially in the tropics and subtropics, since the 1970s. In Australia and Europe, direct links to global warming have been inferred through the extremes in high temperatures and heat waves accompanying recent droughts. {3.3, 3.8, 9.5}

TS.3.5 A Palaeoclimatic Perspective

Palaeoclimatic studies make use of measurements of past change derived from borehole temperatures, ocean sediment pore-water change and glacier extent changes, as well as proxy measurements involving the changes in chemical, physical and biological parameters that reflect past changes in the environment where the proxy grew or existed. Palaeoclimatic studies rely on multiple proxies so that results can be cross-verified and uncertainties better understood. It is now well accepted and verified that many biological organisms (e.g., trees, corals, plankton, animals) alter their growth and/or population dynamics in response to changing climate, and that these climate-induced changes are well recorded in past growth in living and dead (fossil) specimens or assemblages of organisms. Networks of tree ring width and tree ring density chronologies are used to infer past temperature changes based on calibration with temporally overlapping instrumental data. While these methods are heavily used, there are concerns regarding the distributions of available measurements, how well these sample the globe, and such issues as the degree to which the methods have spatial and seasonal biases or apparent divergence in the relationship with recent climate change. {6.2}

It is *very likely* that average NH temperatures during the second half of the 20th century were warmer than any other 50-year period in the last 500 years and *likely* the warmest in at least the past 1300 years. The data supporting these conclusions are most extensive over summer extratropical land areas (particularly for the longer time period; see Figure TS.20). These conclusions are based upon proxy data such as the width and density of a tree ring, the isotopic composition of various elements in ice or the chemical composition of a growth band in corals, requiring analysis to derive temperature information and associated uncertainties. Among the key uncertainties are that temperature and precipitation are difficult to separate in some cases, or are representative of particular seasons rather than full years. There are now improved and expanded data since the TAR, including, for example, measurements at a larger number of sites, improved analysis of borehole temperature data and more extensive analyses of glaciers, corals and sediments. However, palaeoclimatic data are more limited than the instrumental record since 1850 in both space and time, so that statistical methods are employed to construct global averages, and these are subject to uncertainties as well. Current data are too limited to allow a similar evaluation of the SH temperatures prior to the period of instrumental data. {6.6, 6.7}

Some post-TAR studies indicate greater multi-centennial NH variability than was shown in the TAR, due to the particular proxies used and the specific statistical methods of processing and/or scaling them to represent past temperatures. The additional variability implies cooler conditions, predominantly during the 12th to 14th, the 17th and the 19th centuries; these are *likely* linked to natural forcings due to volcanic eruptions and/or solar activity. For example, reconstructions suggest decreased solar activity and increased volcanic activity in the 17th century as compared to current conditions. One reconstruction suggests slightly warmer conditions in the 11th century than those indicated in the TAR, but within the uncertainties quoted in the TAR. {6.6}

The ice core CO_2 record over the past millennium provides an additional constraint on natural climate variability. The amplitudes of the pre-industrial, decadal-scale NH temperature changes from the proxy-based reconstructions (<1°C) are broadly consistent with the ice core CO_2 record and understanding of the strength

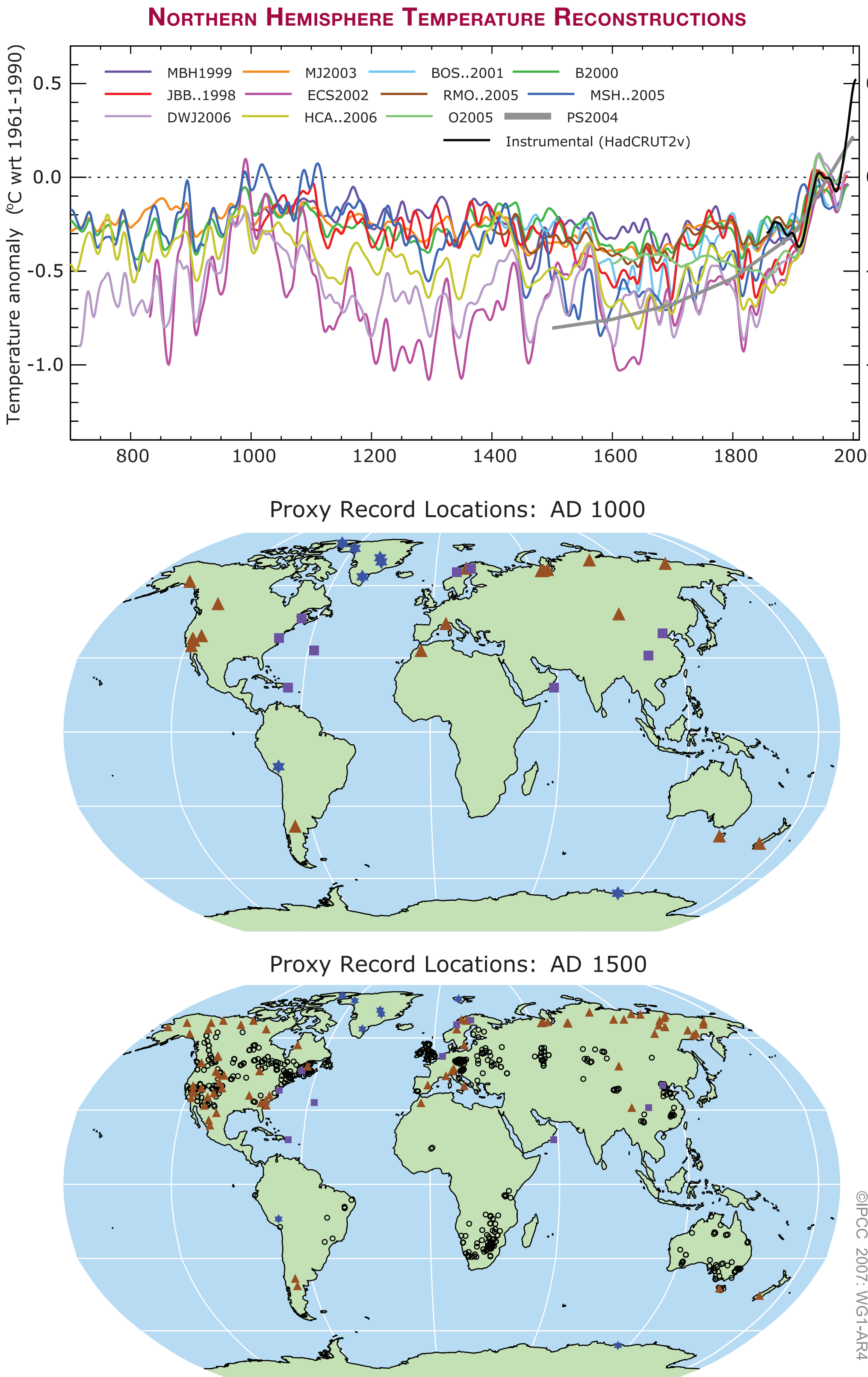


Figure TS.20. *(Top) Records of Northern Hemisphere temperature variation during the last 1300 years with 12 reconstructions using multiple climate proxy records shown in colour and instrumental records shown in black. (Middle and Bottom) Locations of temperature-sensitive proxy records with data back to AD 1000 and AD 1500 (tree rings: brown triangles; boreholes: black circles; ice core/ice boreholes: blue stars; other records including low-resolution records: purple squares). Data sources are given in Table 6.1, Figure 6.10 and are discussed in Chapter 6. {Figures 6.10 and 6.11}*

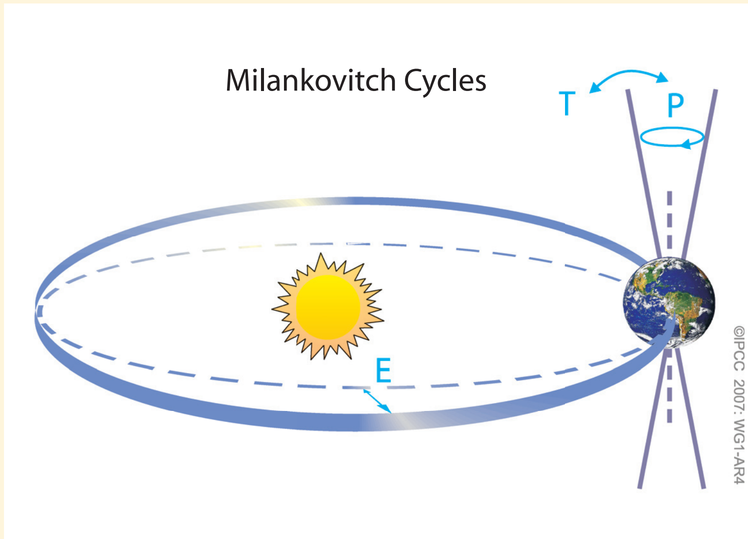
Box TS.6: Orbital Forcing

It is well known from astronomical calculations that periodic changes in characteristics of the Earth's orbit around the Sun control the seasonal and latitudinal distribution of incoming solar radiation at the top of the atmosphere (hereafter called 'insolation'). Past and future changes in insolation can be calculated over several millions of years with a high degree of confidence. {6.4}

Precession refers to changes in the time of the year when the Earth is closest to the Sun, with quasi-periodicities of about 19,000 and 23,000 years. As a result, changes in the position and duration of the seasons on the orbit strongly modulate the latitudinal and seasonal distribution of insolation. Seasonal changes in insolation are much larger than annual mean changes and can reach 60 W m^{-2} (Box TS.6, Figure 1).

The obliquity (tilt) of the Earth's axis varies between about 22° and 24.5° with two neighbouring quasi-periodicities of around 41,000 years. Changes in obliquity modulate seasonal contrasts as well as annual mean insolation changes with opposite effects at low vs. high latitudes (and therefore no effect on global average insolation) {6.4}.

The eccentricity of the Earth's orbit around the Sun has longer quasi-periodicities at 400,000 years and around 100,000 years. Changes in eccentricity alone have limited impacts on insolation, due to the resulting very small changes in the distance between the Sun and the Earth. However, changes in eccentricity interact with seasonal effects induced by obliquity and precession of the equinoxes. During periods of low eccentricity, such as about 400,000 years ago and during the next 100,000 years, seasonal insolation changes induced by precession are not as large as during periods of larger eccentricity (Box TS.6, Figure 1). {6.4}



Box TS.6, Figure 1. *Schematic of the Earth's orbital changes (Milankovitch cycles) that drive the ice age cycles. 'T' denotes changes in the tilt (or obliquity) of the Earth's axis, 'E' denotes changes in the eccentricity of the orbit and 'P' denotes precession, that is, changes in the direction of the axis tilt at a given point of the orbit. {FAQ 6.1, Figure 1}*

The Milankovitch, or 'orbital' theory of the ice ages is now well developed. Ice ages are generally triggered by minima in high-latitude NH summer insolation, enabling winter snowfall to persist through the year and therefore accumulate to build NH glacial ice sheets. Similarly, times with especially intense high-latitude NH summer insolation, determined by orbital changes, are thought to trigger rapid deglaciations, associated climate change and sea level rise. These orbital forcings determine the pacing of climatic changes, while the large responses appear to be determined by strong feedback processes that amplify the orbital forcing. Over multi-millennial time scales, orbital forcing also exerts a major influence on key climate systems such as the Earth's major monsoons, global ocean circulation and the greenhouse gas content of the atmosphere. {6.4}

Available evidence indicates that the current warming will not be mitigated by a natural cooling trend towards glacial conditions. Understanding of the Earth's response to orbital forcing indicates that the Earth would not naturally enter another ice age for at least 30,000 years. {6.4, FAQ 6.1} of the carbon cycle-climate feedback. Atmospheric CO_2 and temperature in Antarctica co-varied over the past 650,000 years. Available data suggest that CO_2 acts as an amplifying feedback. {6.4, 6.6}

Changes in glaciers are evident in Holocene data, but these changes were caused by different processes than the late 20th-century retreat. Glaciers of several mountain regions in the NH retreated in response to orbitally forced regional warmth between 11,000 and 5000 years ago, and were smaller than at the end of the 20th century (or even absent) at times prior to 5000 years ago. The current near-global retreat of mountain glaciers cannot be due to the same causes, because decreased summer insolation during the past few thousand years in the NH should be favourable to the growth of glaciers. {6.5}

Palaeoclimatic data provide evidence for changes in many regional climates. The strength and frequency of ENSO events have varied in past climates. There is evidence that the strength of the Asian monsoon, and hence precipitation amount, can change abruptly. The palaeoclimatic records of northern and eastern Africa and of North America indicate that droughts lasting decades to centuries are a recurrent feature of climate in these regions, so that recent droughts in North America and northern Africa are not unprecedented. Individual decadal-resolution palaeoclimatic data sets support the existence of regional quasi-periodic climate variability, but it is *unlikely* that these regional signals were coherent at the global scale. {6.5, 6.6}

Strong evidence from ocean sediment data and from modelling links abrupt climate changes during the last glacial period and glacial-interglacial transition to changes in the Atlantic Ocean circulation. Current understanding suggests that the ocean circulation can become unstable and change rapidly when critical thresholds are crossed. These events have affected temperature by up to 16°C in Greenland and have influenced tropical rainfall patterns. They were probably associated with a redistribution of heat between the NH and SH rather than with large changes in global mean temperature. Such events have not been observed during the past 8000 years. {6.4}

The Arctic and the Last Interglacial

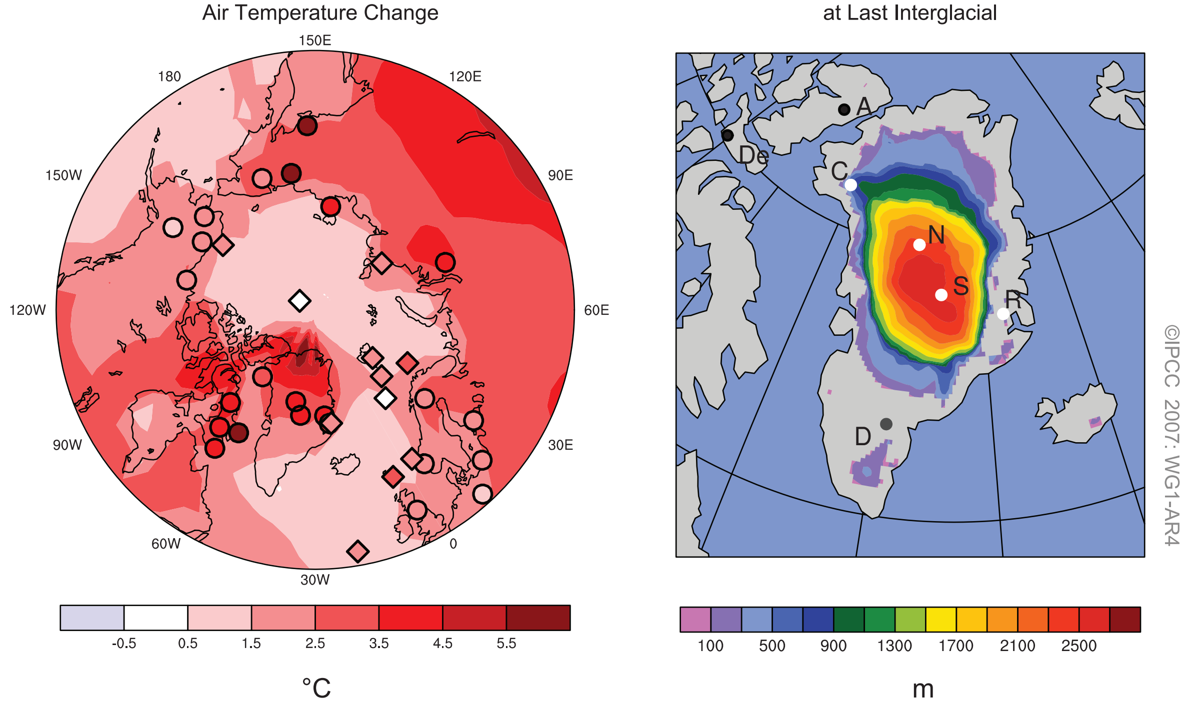


Figure TS.21. *Summer surface air temperature change relative to the present over the Arctic (left) and ice thickness and extent for Greenland and western arctic glaciers (right) for the last interglacial, approximately 125,000 years ago, from a multi-model and multi-proxy synthesis. (Left) A multi-model simulation of summer warming during the last interglacial is overlain by proxy estimates of maximum summer warming from terrestrial (circles) and marine (diamonds) sites. (Right) Extents and thicknesses of the Greenland Ice Sheet and western Canadian and Iceland glaciers at their minimum extent during the last interglacial, shown as a multi-model average from three ice models. Ice core observations indicate ice during the last interglacial at sites (white dots), Renland (R), North Greenland Ice Core Project (N), Summit (S, GRIP and GISP2) and possibly Camp Century (C), but no ice at sites (black dots): Devon (De) and Agassiz (A).Evidence for LIG ice at Dye-3 (D, grey dot) is equivocal. {Figure 6.6}*

Confidence in the understanding of past climate change and changes in orbital forcing is strengthened by the improved ability of current models to simulate past climate conditions. The Last Glacial Maximum (LGM; the last 'ice age' about 21,000 years ago) and the mid-Holocene (6000 years ago) were different from the current climate not because of random variability, but because of altered seasonal and global forcing linked to known differences in the Earth's orbit (see Box TS.6). Biogeochemical and biogeophysical feedbacks amplified the response to orbital forcings. Comparisons between simulated and reconstructed conditions in the LGM demonstrate that models capture the broad features of inferred changes in the temperature and precipitation patterns. For the mid-Holocene, coupled climate models are able to simulate mid-latitude warming and enhanced monsoons, with little change in global mean temperature (<0.4°C), consistent with our understanding of orbital forcing. {6.2, 6.4, 6.5, 9.3}

Global average sea level was likely between 4 and 6 m higher during the last interglacial period, about 125,000 years ago, than during the 20th century, mainly due to the retreat of polar ice (Figure TS.21). Ice core data suggest that the Greenland Summit region was ice-covered during this period, but reductions in the ice sheet extent are indicated in parts of southern Greenland. Ice core data also indicate that average polar temperatures at that time were 3°C to 5°C warmer than the 20th century because of differences in the Earth's orbit. The Greenland Ice Sheet and other arctic ice fields likely contributed no more than 4 m of the observed sea level rise, implying that there may also have been a contribution from Antarctica. {6.4}

TS.4 Understanding and Attributing Climate Change

Attribution evaluates whether observed changes are consistent with quantitative responses to different forcings obtained in well-tested models, and are not consistent with alternative physically plausible explanations. The first IPCC Assessment Report (FAR) contained little observational evidence of a detectable anthropogenic influence on climate. Six years later, the IPCC Second Assessment Report (SAR) concluded that the balance of evidence suggested a discernible human influence on the climate of the 20th century. The TAR concluded that 'most of the observed warming over the last 50 years is likely to have been due to the increase in greenhouse gas concentrations'. Confidence in the assessment of the human contributions to recent climate change has increased considerably since the TAR, in part because of stronger signals obtained from longer records, and an expanded and improved range of observations allowing attribution of warming to be more fully addressed jointly with other changes in the climate system. Some apparent inconsistencies in the observational record (e.g., in the vertical profile of temperature changes) have been largely resolved. There have been improvements in the simulation of many aspects of present mean climate and its variability on seasonal to inter-decadal time scales, although uncertainties remain (see Box TS.7). Models now employ more detailed representations of processes related to aerosol and other forcings. Simulations of 20th-century climate change have used many more models and much more complete anthropogenic and natural forcings than were available for the TAR. Available multi-model ensembles increase confidence in attribution results by providing an improved representation of model uncertainty. An anthropogenic signal has now more clearly emerged in formal attribution studies of aspects of the climate system beyond global-scale atmospheric temperature, including changes in global ocean heat content, continental-scale temperature trends, temperature extremes, circulation and arctic sea ice extent. {9.1}

TS.4.1 Advances in Attribution of Changes in Global-Scale Temperature in the Instrumental Period: Atmosphere, Ocean and Ice

Anthropogenic warming of the climate system is widespread and can be detected in temperature observations taken at the surface, in the free atmosphere and in the oceans. {3.2, 3.4, 9.4}

Evidence of the effect of external influences, both anthropogenic and natural, on the climate system has continued to accumulate since the TAR. Model and data improvements, ensemble simulations and improved representations of aerosol and greenhouse gas forcing along with other influences lead to greater confidence that most current models reproduce large-scale forced variability of the atmosphere on decadal and inter-decadal time scales quite well. These advances confirm that past climate variations at large spatial scales have been strongly influenced by external forcings. However, uncertainties still exist in the magnitude and temporal evolution of estimated contributions from individual forcings other than well-mixed greenhouse gases, due, for

Box TS.7: Evaluation of Atmosphere-Ocean General Circulation Models

Atmosphere-ocean general circulation models (AOGCMs) are the primary tool used for understanding and attribution of past climate variations, and for future projections. Since there are no historical perturbations to radiative forcing that are fully analogous to the human-induced perturbations expected over the 21st century, confidence in the models must be built from a number of indirect methods, described below. In each of these areas there have been substantial advances since the TAR, increasing overall confidence in models. {8.1}

Enhanced scrutiny and analysis of model behaviour has been facilitated by internationally coordinated efforts to collect and disseminate output from model experiments performed under common conditions. This has encouraged a more comprehensive and open evaluation of models, encompassing a diversity of perspectives. {8.1}

Projections for different scales and different periods using global climate models. Climate models project the climate for several decades or longer into the future. Since the details of individual weather systems are not being tracked and forecast, the initial atmospheric conditions are much less important than for weather forecast models. For climate projections, the forcings are of much greater importance. These forcings include the amount of solar energy reaching the Earth, the amount of particulate matter from volcanic eruptions in the atmosphere, and the concentrations of anthropogenic gases and particles in the atmosphere. As the area of interest moves from global to regional to local, or the time scale of interest shortens, the amplitude of variability linked to weather increases relative to the signal of long-term climate change. This makes detection of the climate change signal more difficult at smaller scales. Conditions in the oceans are important as well, especially for interannual and decadal time scales. {FAQ 1.2, 9.4, 11.1}

Model formulation. The formulation of AOGCMs has developed through improved spatial resolution and improvements to numerical schemes and parametrizations (e.g., sea ice, atmospheric boundary layer, ocean mixing). More processes have been included in many models, including a number of key processes important for forcing (e.g., aerosols are now modelled interactively in many models). Most models now maintain a stable climate without use of flux adjustments, although some long-term trends remain in AOGCM control integrations, for example, due to slow processes in the ocean. {8.2, 8.3}

Simulation of present climate. As a result of improvements in model formulation, there have been improvements in the simulation of many aspects of present mean climate. Simulations of precipitation, sea level pressure and surface temperature have each improved overall, but deficiencies remain, notably in tropical precipitation. While significant deficiencies remain in the simulation of clouds (and corresponding feedbacks affecting climate sensitivity), some models have demonstrated improvements in the simulation of certain cloud regimes (notably marine stratocumulus). Simulation of extreme events (especially extreme temperature) has improved, but models generally simulate too little precipitation in the most extreme events. Simulation of extratropical cyclones has improved. Some models used for projections of tropical cyclone changes can simulate successfully the observed frequency and distribution of tropical cyclones. Improved simulations have been achieved for ocean water mass structure, the meridional overturning circulation and ocean heat transport. However most models show some biases in their simulation of the Southern Ocean, leading to some uncertainty in modelled ocean heat uptake when climate changes. {8.3, 8.5, 8.6}

Simulation of modes of climate variability. Models simulate dominant modes of extratropical climate variability that resemble the observed ones (NAM/SAM, PNA, PDO) but they still have problems in representing aspects of them. Some models can now simulate important aspects of ENSO, while simulation of the Madden-Julian Oscillation remains generally unsatisfactory. {8.4}

Simulation of past climate variations. Advances have been made in the simulation of past climate variations. Independently of any attribution of those changes, the ability of climate models to provide a physically self-consistent explanation of observed climate variations on various time scales builds confidence that the models are capturing many key processes for the evolution of 21st-century climate. Recent advances include success in modelling observed changes in a wider range of climate variables over the 20th century (e.g., continental-scale surface temperatures and extremes, sea ice extent, ocean heat content trends and land precipitation). There has also been progress in the ability to model many of the general features of past, very different climate states such as the mid-Holocene and the LGM using identical or related models to those used for studying current climate. Information on factors treated as boundary conditions in palaeoclimate calculations include the different states of ice sheets in those periods. The broad predictions of earlier climate models, of increasing global temperatures in response to increasing greenhouse gases, have been borne out by subsequent observations. This strengthens confidence in near-term climate projections and understanding of related climate change commitments. {6.4, 6.5, 8.1, 9.3–9.5}

(continued)

Weather and seasonal prediction using climate models. A few climate models have been tested for (and shown) capability in initial value prediction, on time scales from weather forecasting (a few days) to seasonal climate variations, when initialised with appropriate observations. While the predictive capability of models in this mode of operation does not necessarily imply that they will show the correct response to changes in climate forcing agents such as greenhouse gases, it does increase confidence that they are adequately representing some key processes and teleconnections in the climate system. {8.4}

Measures of model projection accuracy. The possibility of developing model capability measures ('metrics'), based on the above evaluation methods, that can be used to narrow uncertainty by providing quantitative constraints on model climate projections, has been explored for the first time using model ensembles. While these methods show promise, a proven set of measures has yet to be established. {8.1, 9.6, 10.5}

example, to uncertainties in model responses to forcing. Some potentially important forcings such as black carbon aerosols have not yet been considered in most formal detection and attribution studies. Uncertainties remain in estimates of natural internal climate variability. For example, there are discrepancies between estimates of ocean heat content variability from models and observations, although poor sampling of parts of the world ocean may explain this discrepancy. In addition, internal variability is difficult to estimate from available observational records since these are influenced by external forcing, and because records are not long enough in the case of instrumental data, or precise enough in the case of proxy reconstructions, to provide complete descriptions of variability on decadal and longer time scales (see Figure TS.22 and Box TS.7). {8.2–8.4, 8.6, 9.2–9.4}

It is *extremely unlikely* (<5%) that the global pattern of warming observed during the past half century can be explained without external forcing. These changes took place over a time period when non-anthropogenic forcing factors (i.e., the sum of solar and volcanic forcing) would be *likely* to have produced cooling, not warming (see Figure TS.23). Attribution studies show that it is *very likely* that these natural forcing factors alone cannot account for the observed warming (see Figure TS.23). There is also increased confidence that natural internal variability cannot account for the observed changes, due in part to improved studies demonstrating that the warming occurred in both oceans and atmosphere, together with observed ice mass losses. {2.9, 3.2, 5.2, 9.4, 9.5, 9.7}

It is *very likely* that anthropogenic greenhouse gas increases caused most of the observed increase in global average temperatures since the mid-20th century. Without the cooling effect of atmospheric aerosols, it is *likely* that greenhouse gases alone would have caused a greater global mean temperature rise than that observed during the last 50 years. A key factor in identifying the aerosol fingerprint, and therefore the amount of cooling counteracting greenhouse warming, is the temperature change through time (see Figure TS.23), as well as the hemispheric warming contrast. The conclusion that greenhouse gas forcing has been dominant takes into account observational and forcing uncertainties, and is robust to the use of different climate models, different methods for estimating the responses to external forcing and different analysis techniques. It also allows for possible amplification of the response to solar forcing. {2.9, 6.6, 9.1, 9.2, 9.4}

Widespread warming has been detected in ocean temperatures. Formal attribution studies now suggest that it is *likely* that anthropogenic forcing has contributed to the observed warming of the upper several hundred metres of the global ocean during the latter half of the 20th century. {5.2, 9.5}

Anthropogenic forcing has *likely* contributed to recent decreases in arctic sea ice extent. Changes in arctic sea ice are expected given the observed enhanced arctic warming. Attribution studies and improvements in the modelled representation of sea ice and ocean heat transport strengthen the confidence in this conclusion. {3.3, 4.4, 8.2, 8.3, 9.5}

It is *very likely* that the response to anthropogenic forcing contributed to sea level rise during the latter half of the 20th century, but decadal variability in sea level rise remains poorly understood. Modelled estimates of the contribution to sea level rise from thermal expansion are in good agreement with estimates based on observations during 1961 to 2003, although the budget for sea level rise over that interval is not closed. The observed increase in the rate of loss of mass from glaciers and ice caps is proportional to the global average temperature rise, as expected qualitatively from physical considerations (see Table TS.3). The greater rate of sea level rise in 1993 to 2003 than in 1961 to 2003 may be linked to increasing anthropogenic forcing, which has

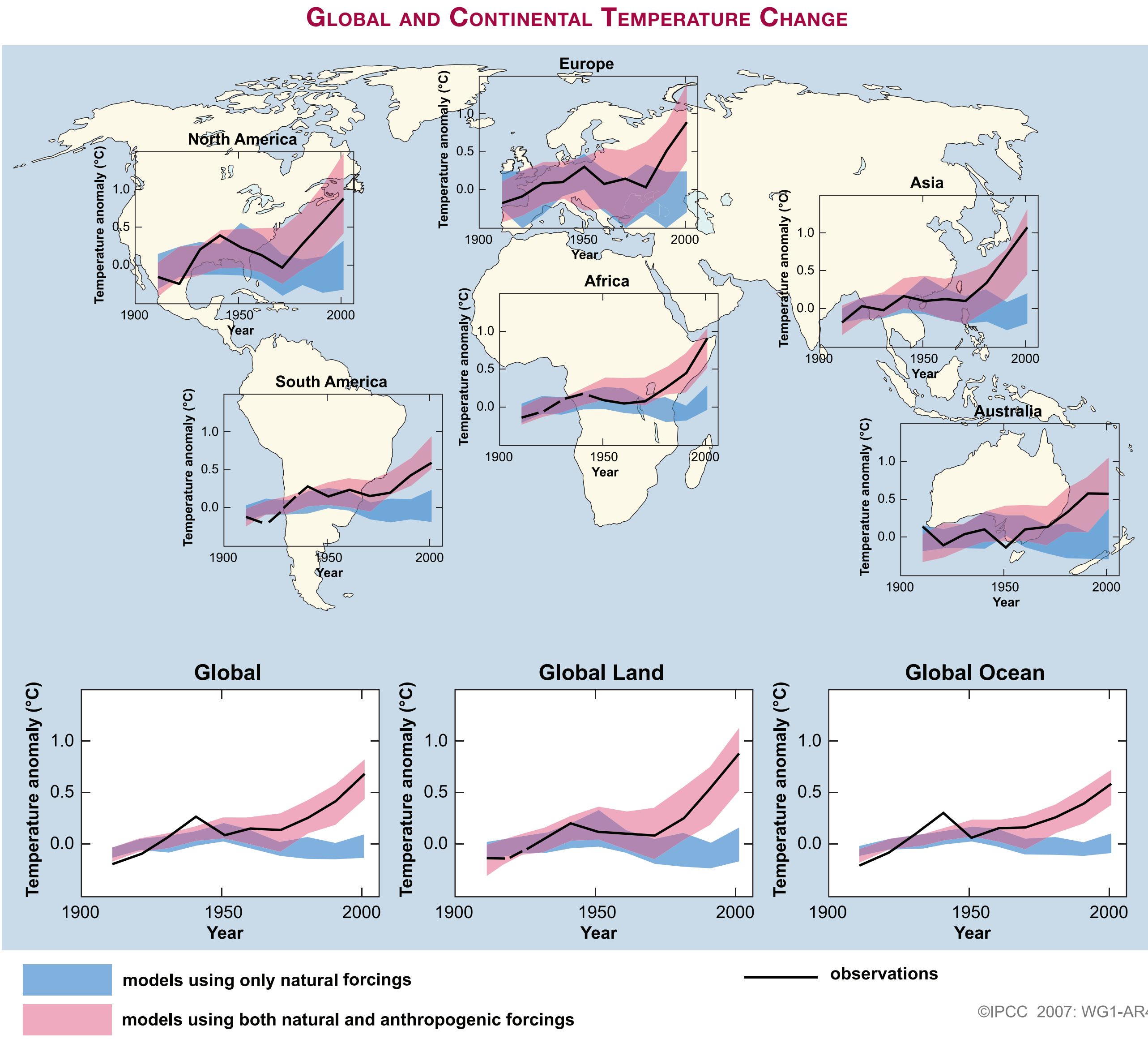


Figure TS.22. *Comparison of observed continental- and global-scale changes in surface temperature with results simulated by climate models using natural and anthropogenic forcings. Decadal averages of observations are shown for the period 1906 to 2005 (black line) plotted against the centre of the decade and relative to the corresponding average for 1901 to 1950. Lines are dashed where spatial coverage is less than 50%. Blue shaded bands show the 5% to 95% range for 19 simulations from 5 climate models using only the natural forcings due to solar activity and volcanoes. Red shaded bands show the 5% to 95% range for 58 simulations from 14 climate models using both natural and anthropogenic forcings. Data sources and models used are described in Section 9.4, FAQ 9.2, Table 8.1 and the supplementary information for Chapter 9. {FAQ 9.2, Figure 1}*

likely contributed to the observed warming of the upper ocean and widespread glacier retreat. On the other hand, the tide gauge record of global mean sea level suggests that similarly large rates may have occurred in previous 10-year periods since 1950, implying that natural internal variability could also be a factor in the high rates for 1993 to 2003 period. Observed decadal variability in the tide gauge record is larger than can be explained by variability in observationally based estimates of thermal expansion and land ice changes. Further, the observed decadal variability in thermal expansion is larger than simulated by models for the 20th century. Thus, the physical causes of the variability seen in the tide gauge record are uncertain. These unresolved issues relating to sea level change and its decadal variability during 1961 to 2003 make it unclear how much of the higher rate of sea level rise in 1993 to 2003 is due to natural internal variability and how much to anthropogenic climate change. {5.5, 9.5}

TS.4.2 Attribution of Spatial and Temporal Changes in Temperature

The observed pattern of tropospheric warming and stratospheric cooling is *very likely* due to the influence of anthropogenic forcing, particularly that due to greenhouse gas increases and stratospheric ozone depletion. New analyses since the TAR show that this pattern corresponds to an increase in the height of the tropopause that is *likely* due largely to greenhouse gas and stratospheric ozone changes. Significant uncertainty remains in the estimation of tropospheric temperature trends, particularly from the radiosonde record. {3.2, 3.4, 9.4}

It is *likely* that there has been a substantial anthropogenic contribution to surface temperature increases averaged over every continent except Antarctica since the middle of the 20th century. Antarctica has insufficient observational coverage to make an assessment. Anthropogenic warming has also been identified in some sub-continental land areas. The ability of coupled climate models to simulate the temperature evolution on each of six continents provides stronger evidence of human influence on the global climate than was available in the TAR. No coupled global climate model that has used natural forcing only has reproduced the observed global mean warming trend, or the continental mean warming trends in individual

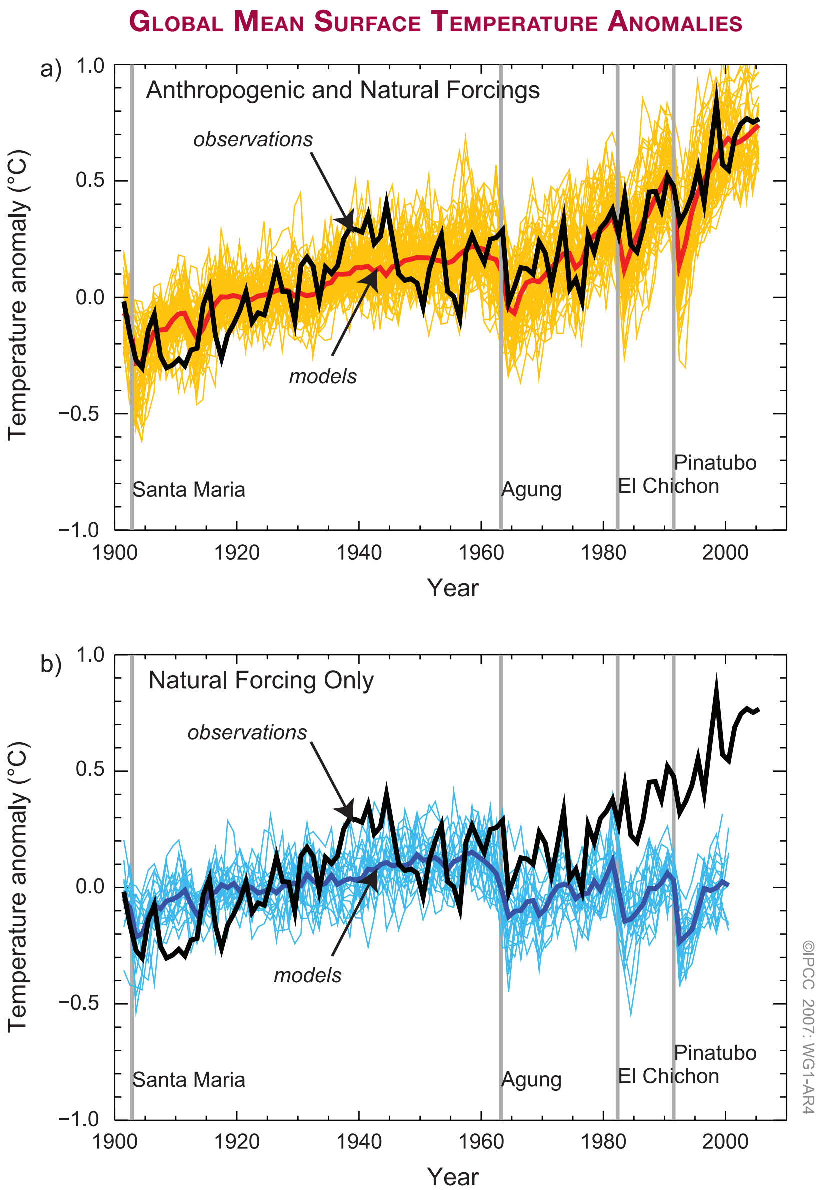


Figure TS.23. *(a) Global mean surface temperature anomalies relative to the period 1901 to 1950, as observed (black line) and as obtained from simulations with both anthropogenic and natural forcings. The thick red curve shows the multi-model ensemble mean and the thin yellow curves show the individual simulations. Vertical grey lines indicate the timing of major volcanic events. (b) As in (a), except that the simulated global mean temperature anomalies are for natural forcings only. The thick blue curve shows the multi-model ensemble mean and the thin lighter blue curves show individual simulations. Each simulation was sampled so that coverage corresponds to that of the observations. {Figure 9.5}* continents (except Antarctica) over the second half of the 20th century. {9.4}

Difficulties remain in attributing temperature changes at smaller than continental scales and over time scales of less than 50 years. Attribution results at these scales have, with limited exceptions, not been established. Averaging over smaller regions reduces the natural variability less than does averaging over large regions, making it more difficult to distinguish between changes expected from external forcing and variability. In addition, temperature changes associated with some modes of variability are poorly simulated by models in some regions and seasons. Furthermore, the small-scale details of external forcing and the response simulated by models are less credible than large-scale features. {8.3, 9.4}

Surface temperature extremes have *likely* been affected by anthropogenic forcing. Many indicators of extremes, including the annual numbers and most extreme values of warm and cold days and nights, as well as numbers of frost days, show changes that are consistent with warming. Anthropogenic influence has been detected in some of these indices, and there is evidence that anthropogenic forcing may have substantially increased the risk of extremely warm summer conditions regionally, such as the 2003 European heat wave. {9.4}

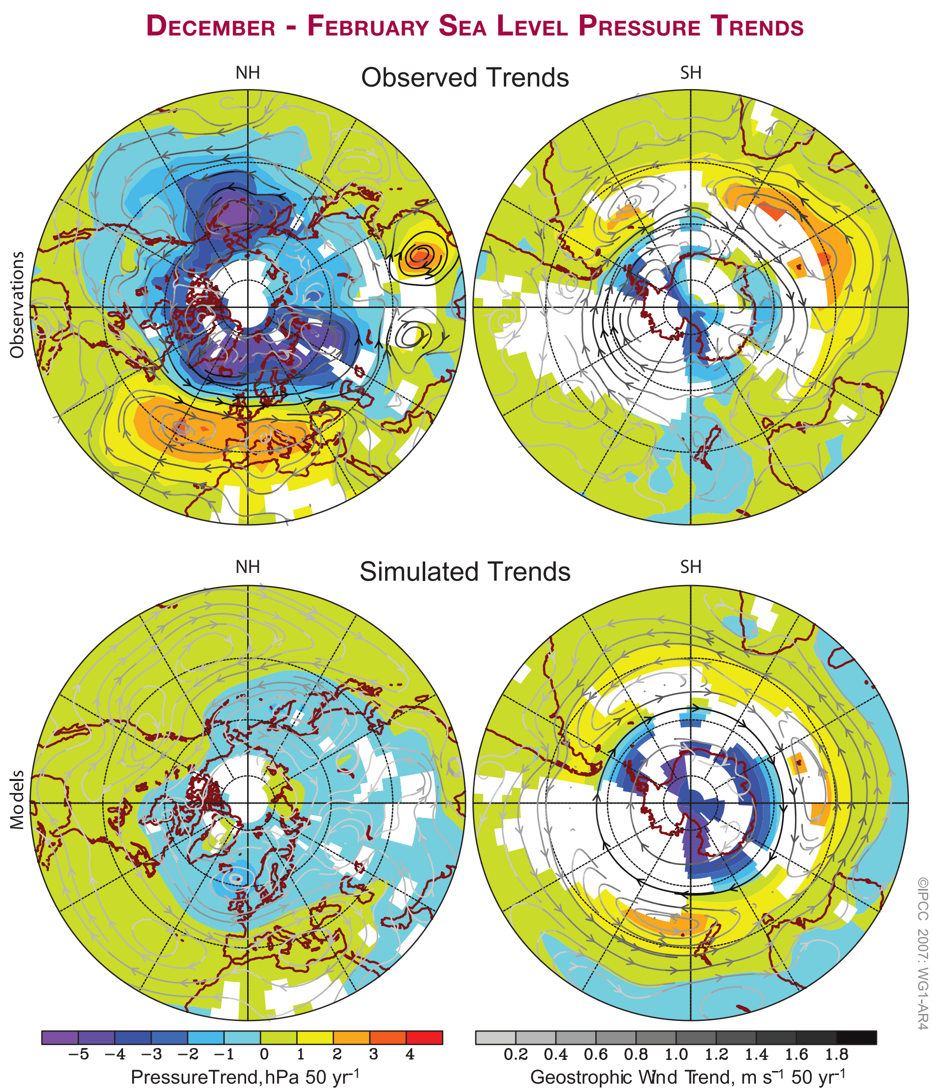


Figure TS.24. *December through February sea level pressure trends based on decadal means for the period 1955 to 2005. (Top) Trends estimated from an observational data set and displayed in regions where there is observational coverage. (Bottom) Mean trends simulated in response to natural and anthropogenic forcing changes in eight coupled models. The model-simulated trends are displayed only where observationally based trends are displayed. Streamlines, which are not masked, indicate the direction of the trends in the geostrophic wind derived from the trends in sea level pressure, and the shading of the streamlines indicates the magnitude of the change, with darker streamlines corresponding to larger changes in geostrophic wind. Data sources and models are described in Chapter 9 and its supplementary material, and Table 8.1 provides model details. {Figure 9.16}*

TS.4.3 Attribution of Changes in Circulation, Precipitation and Other Climate Variables

Trends in the Northern and Southern Annular Modes over recent decades, which correspond to sea level pressure reductions over the poles and related changes in atmospheric circulation, are *likely* related in part to human activity (see Figure TS.24). Models reproduce the sign of the NAM trend, but the simulated response is smaller than observed. Models including both greenhouse gas and stratospheric ozone changes simulate a realistic trend in the SAM, leading to a detectable human influence on global sea level pressure that is also consistent with the observed cooling trend in surface climate over parts of Antarctica. These changes in hemispheric circulation and their attribution to human activity imply that anthropogenic effects have *likely* contributed to changes in mid- and high-latitude patterns of circulation and temperature, as well as changes in winds and storm tracks. However, quantitative effects are uncertain because simulated responses to 20th century forcing change for the NH agree only qualitatively and not quantitatively with observations of these variables. {3.6, 9.5, 10.3}

There is some evidence of the impact of external influences on the hydrological cycle. The observed large-scale pattern of changes in land precipitation over the 20th century is qualitatively consistent with simulations, suggestive of a human influence. An observed global trend towards increases in drought in the second half of the 20th century has been reproduced with a model by taking anthropogenic and natural forcing into account. A number of studies have now demonstrated that changes in land use, due for example to overgrazing and conversion of woodland to agriculture, are *unlikely* to have been the primary cause of Sahelian and Australian droughts. Comparisons between observations and models suggest that changes in monsoons, storm intensities and Sahelian rainfall are related at least in part to changes in observed SSTs. Changes in global SSTs are expected to be affected by anthropogenic forcing, but an association of regional SST changes with forcing has not been established. Changes in rainfall depend not just upon SSTs but also upon changes in the spatial and temporal SST patterns and regional changes in atmospheric circulation, making attribution to human influences difficult. {3.3, 9.5, 10.3, 11.2}

TS.4.4 Palaeoclimate Studies of Attribution

It is *very likely* that climate changes of at least the seven centuries prior to 1950 were not due to unforced variability alone. Detection and attribution studies indicate that a substantial fraction of pre-industrial NH inter-decadal temperature variability contained in reconstructions for those centuries is *very likely* attributable to natural external forcing. Such forcing includes episodic cooling due to known volcanic eruptions, a number of which were larger than those of the 20th century (based on evidence such as ice cores), and long-term variations in solar irradiance, such as reduced radiation during the Maunder Minimum. Further, it is *likely* that anthropogenic forcing contributed to the early 20th-century warming evident in these records. Uncertainties are unlikely to lead to a spurious agreement between temperature reconstructions and forcing reconstructions as they are derived from independent proxies. Insufficient data are available to make a similar SH evaluation. {6.6, 9.3}

TS.4.5 Climate Response to Radiative Forcing

Specification of a *likely* range and a most *likely* value for equilibrium climate sensitivity[8] in this report represents significant progress in quantifying the climate system response to radiative forcing since the TAR and an advance in challenges to understanding that have persisted for over 30 years. A range for equilibrium climate sensitivity – the equilibrium global average warming expected if CO_2 concentrations were to be sustained at double their pre-industrial values (about 550 ppm) – was given in the TAR as between 1.5°C and 4.5°C. It has not been possible previously to provide a best estimate or to estimate the probability that climate sensitivity might fall outside that quoted range. Several approaches are used in this assessment to constrain climate sensitivity, including the use of AOGCMs, examination of the transient evolution of temperature (surface, upper air and ocean) over the last 150 years and examination of the rapid response of the global climate system to changes in the forcing caused by volcanic eruptions (see Figure TS.25). These are complemented by estimates based upon palaeoclimate studies such as reconstructions of the NH temperature record of the past millennium and the LGM. Large ensembles of climate model simulations have shown that the ability of models to simulate present climate has value in constraining climate sensitivity. {8.1, 8.6, 9.6, Box 10.2}

[8] See the Glossary for a detailed definition of climate sensitivity.

Analysis of models together with constraints from observations suggest that the equilibrium climate sensitivity is *likely* to be in the range 2°C to 4.5°C, with a best estimate value of about 3°C. It is *very unlikely* to be less than 1.5°C. Values substantially higher than 4.5°C cannot be excluded, but agreement with observations is not as good for those values. Probability density functions derived from different information and approaches generally tend to have a long tail towards high values exceeding 4.5°C. Analysis of climate and forcing evolution over previous centuries and model ensemble studies do not rule out climate sensitivity being as high as 6°C or more. One factor in this is the possibility of small net radiative forcing over the 20th century if aerosol indirect cooling effects were at the upper end of their uncertainty range, thus cancelling most of the positive forcing due to greenhouse gases. However, there is no well-established way of estimating a single probability distribution function from individual results taking account of the different assumptions in each study. The lack of strong constraints limiting high climate sensitivities prevents the specification of a 95th percentile bound or a very likely range for climate sensitivity. {Box 10.2}

There is now increased confidence in the understanding of key climate processes that are important to climate sensitivity due to improved analyses and comparisons of models to one another and to observations. Water vapour changes dominate the feedbacks affecting climate sensitivity and are now better understood. New observational and modelling evidence strongly favours a combined water vapour-lapse rate[9] feedback of around the strength found in General Circulation Models (GCMs), that is, approximately 1 W m^{-2} per degree global temperature increase, corresponding to about a 50% amplification of global mean warming. Such GCMs have demonstrated an ability to simulate seasonal to inter-decadal humidity variations in the upper troposphere over land and ocean, and have successfully simulated the observed surface temperature and humidity changes associated with volcanic eruptions. Cloud feedbacks (particularly from low clouds) remain the largest source of uncertainty. Cryospheric feedbacks such as changes in snow cover have been shown to contribute less to the spread in model estimates of climate sensitivity than cloud or water vapour feedbacks, but they

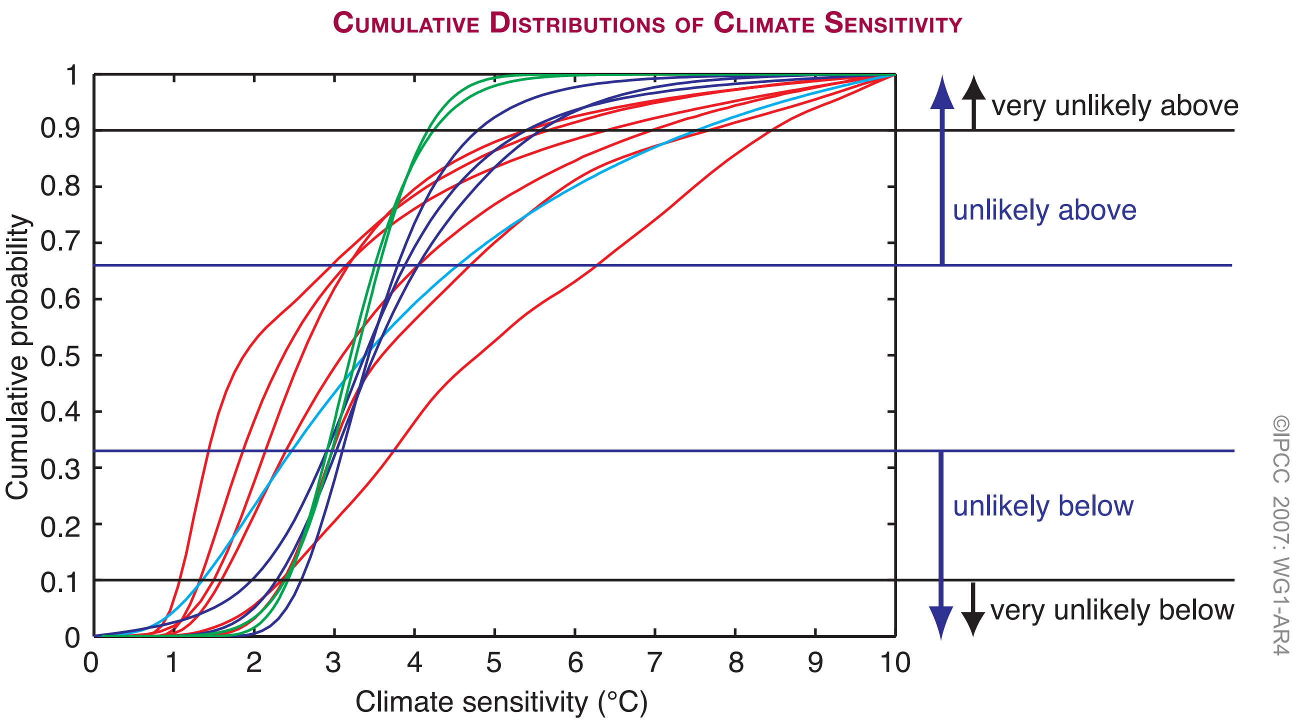


Figure TS.25. *Cumulative distributions of climate sensitivity derived from observed 20th-century warming (red), model climatology (blue), proxy evidence (cyan) and from climate sensitivities of AOGCMs (green). Horizontal lines and arrows mark the boundaries of the likelihood estimates defined in the IPCC Fourth Assessment Uncertainty Guidance Note (see Box TS.1). {Box 10.2, Figures 1 and 2}*

[9] The rate at which air temperature decreases with altitude.

can be important for regional climate responses at mid- and high latitudes. A new model intercomparison suggests that differences in radiative transfer formulations also contribute to the range. {3.4, 8.6, 9.3, 9.4, 9.6, 10.2, Box 10.2}

Improved quantification of climate sensitivity allows estimation of best estimate equilibrium temperatures and ranges that could be expected if concentrations of CO_2 were to be stabilised at various levels based on global energy balance considerations (see Table TS.5). As in the estimate of climate sensitivity, a very likely upper bound cannot be established. Limitations to the concept of radiative forcing and climate sensitivity should be noted. Only a few AOGCMs have been run to equilibrium under elevated CO_2 concentrations, and some results show that climate feedbacks may change over long time scales, resulting in substantial deviations from estimates of warming based on equilibrium climate sensitivity inferred from mixed layer ocean models and past climate change. {10.7}

Agreement among models for projected transient climate change has also improved since the TAR. The range of transient climate responses (defined as the global average surface air temperature averaged over a 20-year period centred at the time of CO_2 doubling in a 1% yr^{-1} increase experiment) among models is smaller than the range in the equilibrium climate sensitivity. This parameter is now better constrained by multi-model ensembles and comparisons with observations; it is *very likely* to be greater than 1°C and *very unlikely* to be greater than 3°C. The transient climate response is related to sensitivity in a nonlinear way such that high sensitivities are not immediately manifested in the short-term response. Transient climate response is strongly affected by the rate of ocean heat uptake. Although the ocean models have improved, systematic model biases and limited ocean temperature data to evaluate transient ocean heat uptake affect the accuracy of current estimates. {8.3, 8.6, 9.4, 9.6, 10.5}

Table TS.5. *Best estimate, likely ranges and very likely lower bounds of global mean equilibrium surface temperature increase (°C) over pre-industrial temperatures for different levels of CO_2-equivalent radiative forcing, as derived from the climate sensitivity.*

Equilibrium CO_2–eq (ppm)	Temperature Increase (°C)		
	Best Estimate	*Very Likely* Above	*Likely* in the Range
350	1.0	0.5	0.6–1.4
450	2.1	1.0	1.4–3.1
550	2.9	1.5	1.9–4.4
650	3.6	1.8	2.4–5.5
750	4.3	2.1	2.8–6.4
1000	5.5	2.8	3.7–8.3
1200	6.3	3.1	4.2–9.4

TS.5 Projections of Future Changes in Climate

Since the TAR, there have been many important advances in the science of climate change projections. An unprecedented effort has been initiated to make new model results available for prompt scrutiny by researchers outside of the modelling centres. A set of coordinated, standard experiments was performed by 14 AOGCM modelling groups from 10 countries using 23 models. The resulting multi-model database of outputs, analysed by hundreds of researchers worldwide, forms the basis for much of this assessment of model results. Many advances have come from the use of multi-member ensembles from single models (e.g., to test the sensitivity of response to initial conditions) and from multi-model ensembles. These two different types of ensembles allow more robust studies of the range of model results and more quantitative model evaluation against observations, and provide new information on simulated statistical variability. {8.1, 8.3, 9.4, 9.5, 10.1}

A number of methods for providing probabilistic climate change projections, both for global means and geographical depictions, have emerged since the TAR and are a focus of this report. These include methods based on results of AOGCM ensembles without formal application of observational constraints as well as methods based on detection algorithms and on large model ensembles that provide projections consistent with observations of climate change and their uncertainties. Some methods now explicitly account for key uncertainty sources such as climate feedbacks, ocean heat uptake, radiative forcing and the carbon cycle. Short-term projections are similarly constrained by observations of recent trends. Some studies have probed additional probabilistic issues, such as the likelihood of future changes in extremes such as heat waves that could occur due to human influences. Advances have also occurred since the TAR through broader ranges of studies of committed climate change and of carbon-climate feedbacks. {8.6, 9.6, 10.1, 10.3, 10.5}

These advances in the science of climate change modelling provide a probabilistic basis for distinguishing projections of climate change for different SRES marker scenarios. This is in contrast to the TAR where ranges for different marker scenarios could not be given in probabilistic terms. As a result, this assessment identifies and quantifies the difference in character between uncertainties that arise in climate modelling and those that arise from a lack of prior knowledge of decisions that will affect greenhouse gas emissions. A loss of policy-relevant information would result from combining probabilistic projections. For these reasons, projections for different emission scenarios are not combined in this report.

Model simulations used here consider the response of the physical climate system to a range of possible future conditions through use of idealised emissions or concentration assumptions. These include experiments with greenhouse gases and aerosols held constant at year 2000 levels, CO_2 doubling and quadrupling experiments, SRES marker scenarios for the 2000 to 2100 period, and experiments with greenhouse gases and aerosols held constant after 2100, providing new information on the physical aspects of long-term climate change and stabilisation. The SRES scenarios did not include climate initiatives. This Working Group I assessment does not evaluate the plausibility or likelihood of any specific emission scenario. {10.1, 10.3}

A new multi-model data set using Earth System Models of Intermediate Complexity (EMICs) complements AOGCM experiments to extend the time horizon for several more centuries in the future. This provides a more comprehensive range of model responses in this assessment as well as new information on climate change over long time scales when greenhouse gas and aerosol concentrations are held constant. Some AOGCMs and EMICs contain prognostic carbon cycle components, which permit estimation of the likely effects and associated uncertainties of carbon cycle feedbacks. {10.1}

Box TS.8: Hierarchy of Global Climate Models

Estimates of change in global mean temperature and sea level rise due to thermal expansion can be made using Simple Climate Models (SCMs) that represent the ocean-atmosphere system as a set of global or hemispheric boxes, and predict global surface temperature using an energy balance equation, a prescribed value of climate sensitivity and a basic representation of ocean heat uptake. Such models can also be coupled to simplified models of biogeochemical cycles and allow rapid estimation of the climate response to a wide range of emission scenarios. {8.8, 10.5}

Earth System Models of Intermediate Complexity (EMICs) include some dynamics of the atmospheric and oceanic circulations, or parametrizations thereof, and often include representations of biogeochemical cycles, but they commonly have reduced spatial resolution. These models can be used to investigate continental-scale climate change and long-term, large-scale effects of coupling between Earth system components using large ensembles of model runs or runs over many centuries. For both SCMs and EMICs it is computationally feasible to sample parameter spaces thoroughly, taking account of parameter uncertainties derived from tuning to more comprehensive climate models, matching observations and use of expert judgment. Thus, both types of model are well suited to the generation of probabilistic projections of future climate and allow a comparison of the 'response uncertainty' arising from uncertainty in climate model parameters with the 'scenario range' arising from the range of emission scenarios being considered. Earth System Models of Intermediate Complexity have been evaluated in greater depth than previously and intercomparison exercises have demonstrated that they are useful for studying questions involving long time scales or requiring large ensembles of simulations. {8.8, 10.5, 10.7}

The most comprehensive climate models are the AOGCMs. They include dynamical components describing atmospheric, oceanic and land surface processes, as well as sea ice and other components. Much progress has been made since the TAR (see Box TS.7), and there are over 20 models from different centres available for climate simulations. Although the large-scale dynamics of these models are comprehensive, parametrizations are still used to represent unresolved physical processes such as the formation of clouds and precipitation, ocean mixing due to wave processes and the formation of water masses, etc. Uncertainty in parametrizations is the primary reason why climate projections differ between different AOGCMs. While the resolution of AOGCMs is rapidly improving, it is often insufficient to capture the fine-scale structure of climatic variables in many regions. In such cases, the output from AOGCMs can be used to drive limited-area (or regional climate) models that combine the comprehensiveness of process representations comparable to AOGCMs with much higher spatial resolution. {8.2}

TS.5.1 Understanding Near-Term Climate Change

Knowledge of the climate system together with model simulations confirm that past changes in greenhouse gas concentrations will lead to a committed warming (see Box TS.9 for a definition) and future climate change. New model results for experiments in which concentrations of all forcing agents were held constant provide better estimates of the committed changes in atmospheric variables that would follow because of the long response time of the climate system, particularly the oceans. {10.3, 10.7}

Previous IPCC projections of future climate changes can now be compared to recent observations, increasing confidence in short-term projections and the underlying physical understanding of committed climate change over a few decades. Projections for 1990 to 2005 carried out for the FAR and the SAR suggested global mean temperature increases of about 0.3°C and 0.15°C per decade, respectively.[10] The difference between the two was due primarily to the inclusion of aerosol cooling effects in the SAR, whereas there was no quantitative basis for doing so in the FAR. Projections given in the TAR were similar to those of the SAR. These results are comparable to observed values of about 0.2°C per decade, as shown in Figure TS.26, providing broad confidence in such short-term projections. Some of this warming is the committed effect of changes in the concentrations of greenhouse gases prior to the times of those earlier assessments. {1.2, 3.2}

Committed climate change (see Box TS.9) due to atmospheric composition in the year 2000 corresponds to a warming trend of about 0.1°C per decade over the next two decades, in the absence of large changes in volcanic or solar forcing. About twice as much warming (0.2°C per decade) would be expected if emissions were to fall within the range of the SRES marker scenarios. This result is insensitive to the choice among the SRES marker scenarios, none of which considered climate initiatives. By 2050, the range of expected warming shows limited sensitivity to the choice among SRES scenarios (1.3°C to 1.7°C relative to 1980–1999) with about a quarter being due to the committed climate change if all radiative forcing agents were stabilised today. {10.3, 10.5, 10.7}

Sea level is expected to continue to rise over the next several decades. During 2000 to 2020 under the SRES A1B scenario in the ensemble of AOGCMs, the rate of thermal expansion is projected to be 1.3 ± 0.7 mm yr^{-1}, and is not significantly different under the A2 or B1 scenarios. These projected rates are within the uncertainty of the observed contribution of thermal expansion for 1993 to 2003 of 1.6 ± 0.6 mm yr^{-1}. The ratio of committed thermal expansion, caused by constant atmospheric composition at year 2000 values, to total thermal expansion (that is the ratio of expansion occurring after year 2000 to that occurring before and after) is larger than the corresponding ratio for global average surface temperature. {10.6, 10.7}

Box TS.9: Committed Climate Change

If the concentrations of greenhouse gases and aerosols were held fixed after a period of change, the climate system would continue to respond due to the thermal inertia of the oceans and ice sheets and their long time scales for adjustment. ‘Committed warming’ is defined here as the further change in global mean temperature after atmospheric composition, and hence radiative forcing, is held constant. Committed change also involves other aspects of the climate system, in particular sea level. Note that holding concentrations of radiatively active species constant would imply that ongoing emissions match natural removal rates, which for most species would be equivalent to a large reduction in emissions, although the corresponding model experiments are not intended to be considered as emission scenarios. {FAQ 10.3}

The troposphere adjusts to changes in its boundary conditions over time scales shorter than a month or so. The upper ocean responds over time scales of several years to decades, and the deep ocean and ice sheet response time scales are from centuries to millennia. When the radiative forcing changes, internal properties of the atmosphere tend to adjust quickly. However, because the atmosphere is strongly coupled to the oceanic mixed layer, which in turn is coupled to the deeper oceanic layer, it takes a very long time for the atmospheric variables to come to an equilibrium. During the long periods where the surface climate is changing very slowly, one can consider that the atmosphere is in a quasi-equilibrium state, and most energy is being absorbed by the ocean, so that ocean heat uptake is a key measure of climate change. {10.7}

[10] See IPCC First Assessment Report, Policymakers Summary, and Second Assessment Report, Technical Summary, Figure 18.

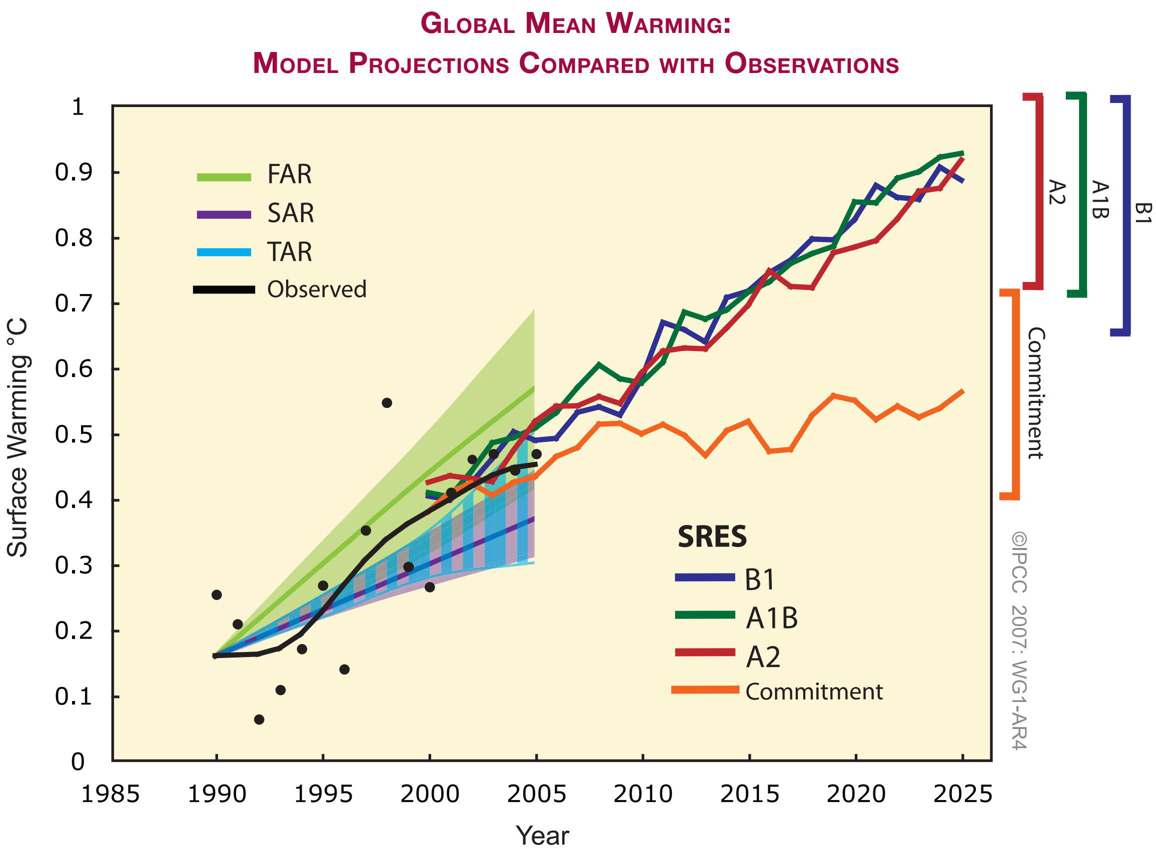


Figure TS.26. *Model projections of global mean warming compared to observed warming. Observed temperature anomalies, as in Figure TS.6, are shown as annual (black dots) and decadal average values (black line). Projected trends and their ranges from the IPCC First (FAR) and Second (SAR) Assessment Reports are shown as green and magenta solid lines and shaded areas, and the projected range from the TAR is shown by vertical blue bars. These projections were adjusted to start at the observed decadal average value in 1990. Multi-model mean projections from this report for the SRES B1, A1B and A2 scenarios, as in Figure TS.32, are shown for the period 2000 to 2025 as blue, green and red curves with uncertainty ranges indicated against the right-hand axis. The orange curve shows model projections of warming if greenhouse gas and aerosol concentrations were held constant from the year 2000 – that is, the committed warming. {Figures 1.1 and 10.4}*

TS.5.2 Large-Scale Projections for the 21st Century

This section covers advances in understanding global-scale climate projections and the processes that will influence their large-scale patterns in the 21st century. More specific discussion of regional-scale changes follows in TS.5.3.

Projected global average surface warming for the end of the 21st century (2090–2099) is scenario-dependent and the actual warming will be significantly affected by the actual emissions that occur. Warmings compared to 1980 to 1999 for six SRES scenarios[11] and for constant year 2000 concentrations, given as best estimates and corresponding *likely* ranges, are shown in Table TS.6. These results are based on AOGCMs, observational constraints and other methods to quantify the range of model response (see Figure TS.27). The combination of multiple lines of evidence allows likelihoods to be assigned to the resulting ranges, representing an important advance since the TAR. {10.5}

Assessed uncertainty ranges are larger than those given in the TAR because they consider a more complete range of models and climate-carbon cycle feedbacks. Warming tends to reduce land and ocean uptake of atmospheric CO_2, increasing the fraction of anthropogenic emissions that remains in the atmosphere. For the A2 scenario for example, the CO_2 feedback increases the corresponding global average warming in 2100 by more than 1°C. {7.3, 10.5}

[11] Approximate CO_2 equivalent concentrations corresponding to the computed radiative forcing due to anthropogenic greenhouse gases and aerosols in 2100 (see p. 823 of the TAR) for the SRES B1, A1T, B2, A1B, A2 and A1FI illustrative marker scenarios are about 600, 700, 800, 850, 1,250 and 1,550 ppm respectively. Constant emission at year 2000 levels would lead to a concentration for CO_2 alone of about 520 ppm by 2100.

Table TS.6. *Projected global average surface warming and sea level rise at the end of the 21st century. {10.5, 10.6, Table 10.7}*

Case	Temperature Change (°C at 2090-2099 relative to 1980-1999) [a]		Sea Level Rise (m at 2090-2099 relative to 1980-1999)
	Best estimate	*Likely* range	Model-based range excluding future rapid dynamical changes in ice flow
Constant Year 2000 concentrations [b]	0.6	0.3 – 0.9	NA
B1 scenario	1.8	1.1 – 2.9	0.18 – 0.38
A1T scenario	2.4	1.4 – 3.8	0.20 – 0.45
B2 scenario	2.4	1.4 – 3.8	0.20 – 0.43
A1B scenario	2.8	1.7 – 4.4	0.21 – 0.48
A2 scenario	3.4	2.0 – 5.4	0.23 – 0.51
A1FI scenario	4.0	2.4 – 6.4	0.26 – 0.59

Notes:
[a] These estimates are assessed from a hierarchy of models that encompass a simple climate model, several Earth Models of Intermediate Complexity (EMICs), and a large number of Atmosphere-Ocean Global Circulation Models (AOGCMs).
[b] Year 2000 constant composition is derived from AOGCMs only.

Projected global-average sea level rise at the end of the 21st century (2090 to 2099), relative to 1980 to 1999 for the six SRES marker scenarios, given as 5% to 95% ranges based on the spread of model results, are shown in Table TS.6. Thermal expansion contributes 70 to 75% to the best estimate for each scenario. An improvement since the TAR is the use of AOGCMs to evaluate ocean heat uptake and thermal expansion. This has also reduced the projections as compared to the simple model used in the TAR. In all the SRES marker scenarios except B1, the average rate of sea level rise during the 21st century *very likely* exceeds the 1961–2003 average rate (1.8 ± 0.5 mm yr^{-1}). For an average model, the scenario spread in sea level rise is only 0.02 m by the middle of the century, but by the end of the century it is 0.15 m. These ranges do not include uncertainties in carbon-cycle feedbacks or ice flow processes because a basis in published literature is lacking. {10.6, 10.7}

For each scenario, the midpoint of the range given here is within 10% of the TAR model average for 2090–2099, noting that the TAR projections were given for 2100, whereas projections in this report are for 2090–2099. The uncertainty in these projections is less than in the TAR for several reasons: uncertainty in land ice models is assumed independent of uncertainty in temperature and expansion projections; improved observations of recent mass loss from glaciers provide a better observational constraint; and the present report gives uncertainties as 5% to 95% ranges, equivalent to ±1.65 standard deviations, whereas the TAR gave uncertainty ranges of ±2 standard deviations. The TAR would have had similar ranges for sea level projections to those in this report if it had treated the uncertainties in the same way. {10.6, 10.7}

Changes in the cryosphere will continue to affect sea level rise during the 21st century. Glaciers, ice caps and the Greenland Ice Sheet are projected to lose mass in the 21st century because increased melting will exceed increased snowfall. Current models suggest that the Antarctic Ice Sheet will remain too cold for widespread melting and may gain mass in future through increased snowfall, acting to reduce sea level rise. However, changes in ice dynamics could increase the contributions of both Greenland and Antarctica to 21st-century sea level rise. Recent observations of some Greenland outlet glaciers give strong evidence for enhanced flow when ice shelves are removed. The observations in west-central Greenland of seasonal variation in ice flow rate and of a correlation with summer temperature variation suggest that surface melt water may join a sub-glacially routed drainage system lubricating the ice flow. By both of these mechanisms, greater surface melting during the 21st century could cause acceleration of ice flow and discharge and increase the sea level contribution. In some parts of West Antarctica, large accelerations of ice flow have recently occurred, which may have been caused by thinning of ice shelves due to ocean warming. Although this has not been formally attributed to anthropogenic climate change due to greenhouse gases, it suggests that future warming could cause faster mass loss and greater

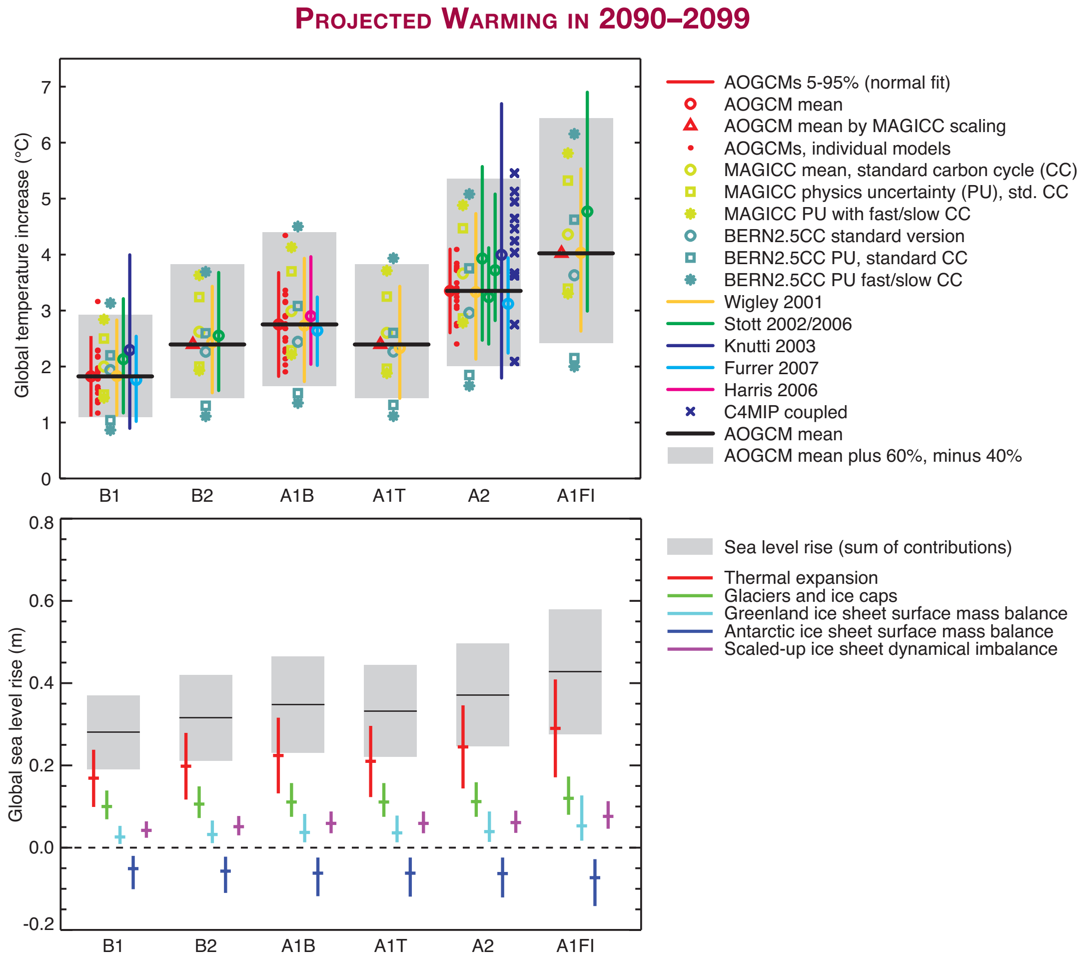


Figure TS.27. *(Top) Projected global mean temperature change in 2090 to 2099 relative to 1980 to 1999 for the six SRES marker scenarios based on results from different and independent models. The multi-model AOGCM mean and the range of the mean minus 40% to the mean plus 60% are shown as black horizontal solid lines and grey bars, respectively. Carbon cycle uncertainties are estimated for scenario A2 based on Coupled Carbon Cycle Climate Model Intercomparison Project (C⁴MIP) models (dark blue crosses), and for all marker scenarios using an EMIC (pale blue symbols). Other symbols represent individual studies (see Figure 10.29 for details of specific models). (Bottom) Projected global average sea level rise and its components in 2090 to 2099 (relative to 1980–1999) for the six SRES marker scenarios. The uncertainties denote 5 to 95% ranges, based on the spread of model results, and not including carbon cycle uncertainties. The contributions are derived by scaling AOGCM results and estimating land ice changes from temperature changes (see Appendix 10.A for details). Individual contributions are added to give the total sea level rise, which does not include the contribution shown for ice sheet dynamical imbalance, for which the current level of understanding prevents a best estimate from being given. {Figures 10.29 and 10.33}*

sea level rise. Quantitative projections of this effect cannot be made with confidence. If recently observed increases in ice discharge rates from the Greenland and Antarctic Ice Sheets were to increase linearly with global average temperature change, that would add 0.1 to 0.2 m to the upper bound of sea level rise. Understanding of these effects is too limited to assess their likelihood or to give a best estimate. {4.6, 10.6}

Many of the global and regional patterns of temperature and precipitation seen in the TAR projections remain in the new generation of models and across ensemble results (see Figure TS.28). Confidence in the robustness of these patterns is increased by the fact that they have remained largely unchanged while overall model simulations have improved (Box TS.7). This adds to confidence that these patterns reflect basic physical constraints on the climate system as it warms. {8.3–8.5, 10.3, 11.2–11.9}

The projected 21st-century temperature change is positive everywhere. It is greatest over land and at most high latitudes in the NH during winter, and increases going from the coasts into the continental interiors. In otherwise geographically similar areas, warming is typically larger in arid than in moist regions. {10.3, 11.2–11.9}

In contrast, warming is least over the southern oceans and parts of the North Atlantic Ocean. Temperatures are projected to increase, including over the North Atlantic and Europe, despite a projected slowdown of the meridional overturning circulation (MOC) in most models, due to the much larger influence of the increase in greenhouse gases. The projected pattern of zonal mean temperature change in the atmosphere displays a maximum warming in the upper tropical troposphere and cooling in the stratosphere. Further zonal mean warming in the ocean is expected to occur first near the surface and in the northern mid-latitudes, with the warming gradually reaching the ocean interior, most evident at high latitudes where vertical mixing is greatest. The projected pattern of change is very similar among the late-century cases irrespective of the scenario. Zonally averaged fields normalised by the mean warming are very similar for the scenarios examined (see Figure TS.28). {10.3}

It is *very likely* that the Atlantic MOC will slow down over the course of the 21st century. The multi-model average reduction by 2100 is 25% (range from zero to about 50%) for SRES emission scenario A1B. Temperatures in the Atlantic region are projected to increase despite such changes due to the much larger warming associated with projected increases of greenhouse gases. The projected reduction of the Atlantic MOC is due to the combined effects of an increase in high latitude temperatures and precipitation, which reduce the density of the surface waters in the North Atlantic. This could lead to a significant reduction in Labrador Sea Water formation. Very few AOGCM studies have included the impact of additional freshwater from melting of the Greenland Ice Sheet, but those that have do not suggest that this will lead to a complete MOC shutdown. Taken together, it is *very likely* that the MOC will reduce, but very *unlikely* that the MOC will undergo a large abrupt transition during the course of the 21st century. Longer-term changes in the MOC cannot be assessed with confidence. {8.7, 10.3}

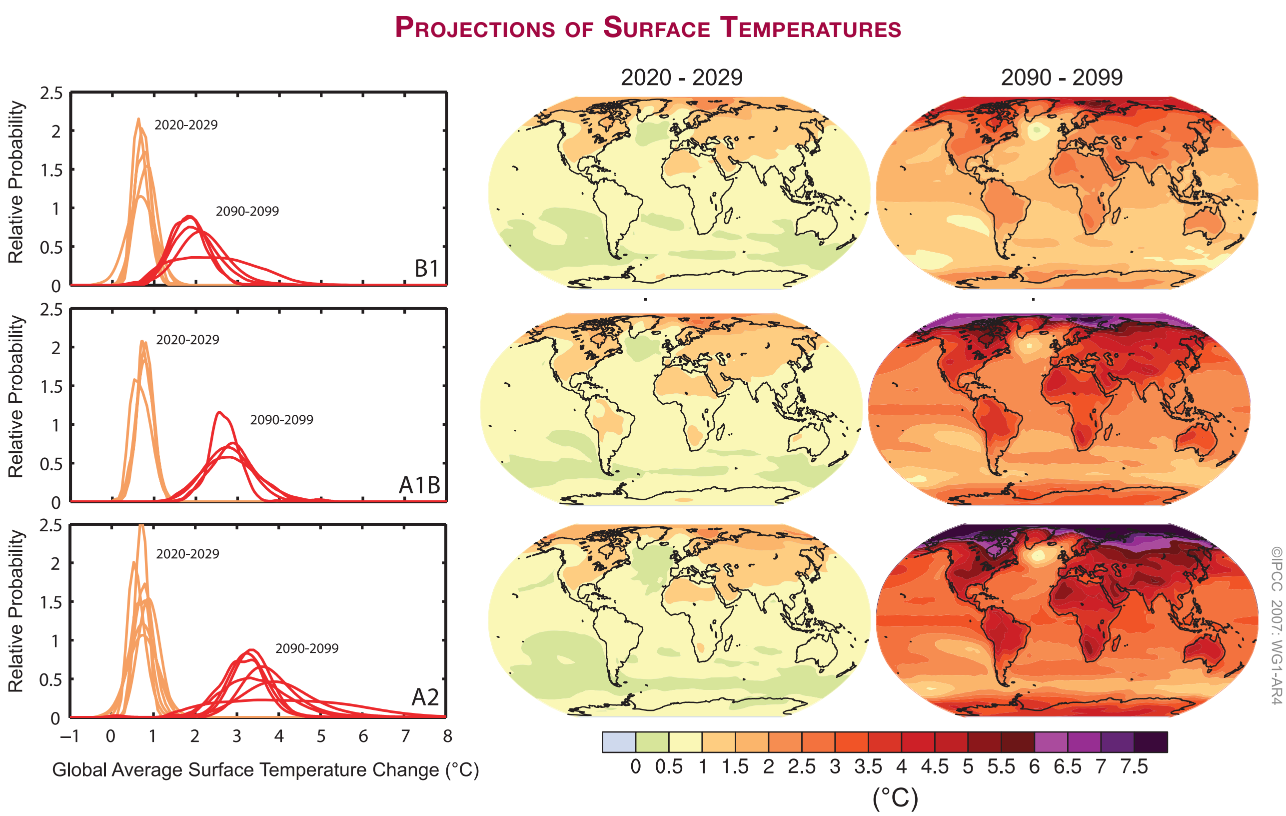


Figure TS.28. *Projected surface temperature changes for the early and late 21st century relative to the period 1980 to 1999. The central and right panels show the AOGCM multi-model average projections (°C) for the B1 (top), A1B (middle) and A2 (bottom) SRES scenarios averaged over the decades 2020 to 2029 (centre) and 2090 to 2099 (right). The left panel shows corresponding uncertainties as the relative probabilities of estimated global average warming from several different AOGCM and EMIC studies for the same periods. Some studies present results only for a subset of the SRES scenarios, or for various model versions. Therefore the difference in the number of curves, shown in the left-hand panels, is due only to differences in the availability of results. {Adapted from Figures 10.8 and 10.28}*

Models indicate that sea level rise during the 21st century will not be geographically uniform. Under scenario A1B for 2070 to 2099, AOGCMs give a median spatial standard deviation of 0.08 m, which is about 25% of the central estimate of the global average sea level rise. The geographic patterns of future sea level change arise mainly from changes in the distribution of heat and salinity in the ocean and consequent changes in ocean circulation. Projected patterns display more similarity across models than those analysed in the TAR. Common features are a smaller than average sea level rise in the Southern Ocean, larger than average sea level rise in the Arctic and a narrow band of pronounced sea level rise stretching across the southern Atlantic and Indian Oceans. {10.6}

Projections of changes in extremes such as the frequency of heat waves are better quantified than in the TAR, due to improved models and a better assessment of model spread based on multi-model ensembles. The TAR concluded that there was a risk of increased temperature extremes, with more extreme heat episodes in a future climate. This result has been confirmed and expanded in more recent studies. Future increases in temperature extremes are projected to follow increases in mean temperature over most of the world except where surface properties (e.g., snow cover or soil moisture) change. A multi-model analysis, based on simulations of 14 models for three scenarios, investigated changes in extreme seasonal (DJF and JJA) temperatures where 'extreme' is defined as lying above the 95th percentile of the simulated temperature distribution for the 20th century. By the end of the 21st century, the projected probability of extreme warm seasons rises above 90% in many tropical areas, and reaches around 40% elsewhere. Several recent studies have addressed possible future changes in heat waves, and found that, in a future climate, heat waves are expected to be more intense, longer lasting and more frequent. Based on an eight-member multi-model ensemble, heat waves are simulated to have been increasing for the latter part of the 20th century, and are projected to increase globally and over most regions. {8.5, 10.3}

For a future warmer climate, models project a 50 to 100% decline in the frequency of cold air outbreaks relative to the present in NH winters in most areas. Results from a nine-member multi-model ensemble show simulated decreases in frost days for the 20th century continuing into the 21st century globally and in most regions. Growing season length is related to frost days and is projected to increase in future climates. {10.3, FAQ 10.1}

Snow cover is projected to decrease. Widespread increases in thaw depth are projected to occur over most permafrost regions. {10.3}

Under several different scenarios (SRES A1B, A2 and B1), large parts of the Arctic Ocean are expected to no longer have year-round ice cover by the end of the 21st century. Arctic sea ice responds sensitively to warming. While projected changes in winter sea ice extent are moderate, late-summer sea ice is projected to disappear almost completely towards the end of the 21st century under the A2 scenario in some models. The reduction is accelerated by a number of positive feedbacks in the climate system. The ice-albedo feedback allows open water to receive more heat from the Sun during summer, the insulating effect of sea ice is reduced and the increase in ocean heat transport to the Arctic further reduces ice cover. Model simulations indicate that the late-summer sea ice cover decreases substantially and generally evolves over the same time scale as global warming. Antarctic sea ice extent is also projected to decrease in the 21st century. {8.6, 10.3, Box 10.1}

Sea level pressure is projected to increase over the subtropics and mid-latitudes, and decrease over high latitudes associated with an expansion of the Hadley Circulation and annular mode changes (NAM/NAO and SAM, see Box TS.2). A positive trend in the NAM/NAO as well as the SAM index is projected by many models. The magnitude of the projected increase is generally greater for the SAM, and there is considerable spread among the models. As a result of these changes, storm tracks are projected to move poleward, with consequent changes in wind, precipitation and temperature patterns outside the tropics, continuing the broad pattern of observed trends over the last half century. Some studies suggest fewer storms in mid-latitude regions. There are also indications of changes in extreme wave height associated with changing storm tracks and circulation. {3.6, 10.3}

In most models, the central and eastern equatorial Pacific SSTs warm more than those in the western equatorial Pacific, with a corresponding mean eastward shift in precipitation. ENSO interannual variability is projected to continue in all models, although changes differ from model to model. Large inter-model differences in projected changes in El Niño amplitude, and the inherent centennial time-scale variability of El Niño in the models, preclude a definitive projection of trends in ENSO variability. {10.3}

Recent studies with improved global models, ranging in resolution from about 100 to 20 km, suggest future changes in the number and intensity of future tropical cyclones (typhoons and hurricanes).

A synthesis of the model results to date indicates, for a warmer future climate, increased peak wind intensities and increased mean and peak precipitation intensities in future tropical cyclones, with the possibility of a decrease in the number of relatively weak hurricanes, and increased numbers of intense hurricanes. However, the total number of tropical cyclones globally is projected to decrease. The apparent observed increase in the proportion of very intense hurricanes since 1970 in some regions is in the same direction but much larger than predicted by theoretical models. {10.3, 8.5, 3.8}

Since the TAR, there is an improving understanding of projected patterns of precipitation. Increases in the amount of precipitation are *very likely* at high latitudes while decreases are *likely* in most subtropical land regions (by as much as about 20% in the A1B scenario in 2100). Poleward of 50°, mean precipitation is projected to increase due to the increase in water vapour in the atmosphere and the resulting increase in vapour transport from lower latitudes. Moving equatorward, there is a transition to mostly decreasing precipitation in the subtropics (20°–40° latitude). Due to increased water vapour transport out of the subtropics and a poleward expansion of the subtropical high-pressure systems, the drying tendency is especially pronounced at the higher-latitude margins of the subtropics (see Figure TS.30). {8.3, 10.3, 11.2–11.9}

Models suggest that changes in mean precipitation amount, even where robust, will rise above natural variability more slowly than the temperature signal. {10.3, 11.1}

Available research indicates a tendency for an increase in heavy daily rainfall events in many regions, including some in which the mean rainfall is projected to decrease. In the latter cases, the rainfall decrease is often attributable to a reduction in the number of rain days rather than the intensity of rain when it occurs. {11.2–11.9}

TS.5.3 Regional-Scale Projections

For each of the continental regions, the projected warming over 2000 to 2050 resulting from the SRES emissions scenarios is greater than the global average and greater than the observed warming over the past century. The warming projected for the next few decades of the 21st century, when averaged over the continents individually, would substantially exceed estimated 20th-century natural forced and unforced variability in all cases except Antarctica (Figure TS.29). Model best-estimate projections indicate that decadal average warming over each continent except Antarctica by 2030 is *very likely* to be at least twice as large as the corresponding model-estimated natural variability during the 20th century. The simulated warming over this period is not very sensitive to the choice of scenarios across the SRES set as is illustrated in Figure TS.32. Over longer time scales, the choice of scenario is more important, as shown in Figure TS.28. The projected warming in the SRES scenarios over 2000 to 2050 also exceeds estimates of natural variability when averaged over most sub-continental regions. {11.1}

Box TS.10. Regional Downscaling

Simulation of regional climates has improved in AOGCMs and, as a consequence, in nested regional climate models and in empirical downscaling techniques. Both dynamic and empirical downscaling methodologies show improving skill in simulating local features in present-day climates when the observed state of the atmosphere at scales resolved by current AOGCMs is used as input. The availability of downscaling and other regionally focused studies remains uneven geographically, causing unevenness in the assessments that can be provided, particularly for extreme weather events. Downscaling studies demonstrate that local precipitation changes can vary significantly from those expected from the large-scale hydrological response pattern, particularly in areas of complex topography. {11.10}

There remain a number of important sources of uncertainty limiting the ability to project regional climate change. While hydrological responses are relatively robust in certain core subpolar and subtropical regions, there is uncertainty in the precise location of these boundaries between increasing and decreasing precipitation. There are some important climate processes that have a significant effect on regional climate, but for which the climate change response is still poorly known. These include ENSO, the NAO, blocking, the thermohaline circulation and changes in tropical cyclone distribution. For those regions that have strong topographical controls on their climatic patterns, there is often insufficient climate change information at the fine spatial resolution of the topography. In some regions there has been only very limited research on extreme weather events. Further, the projected climate change signal becomes comparable to larger internal variability at smaller spatial and temporal scales, making it more difficult to utilise recent trends to evaluate model performance. {Box 11.1, 11.2–11.9}

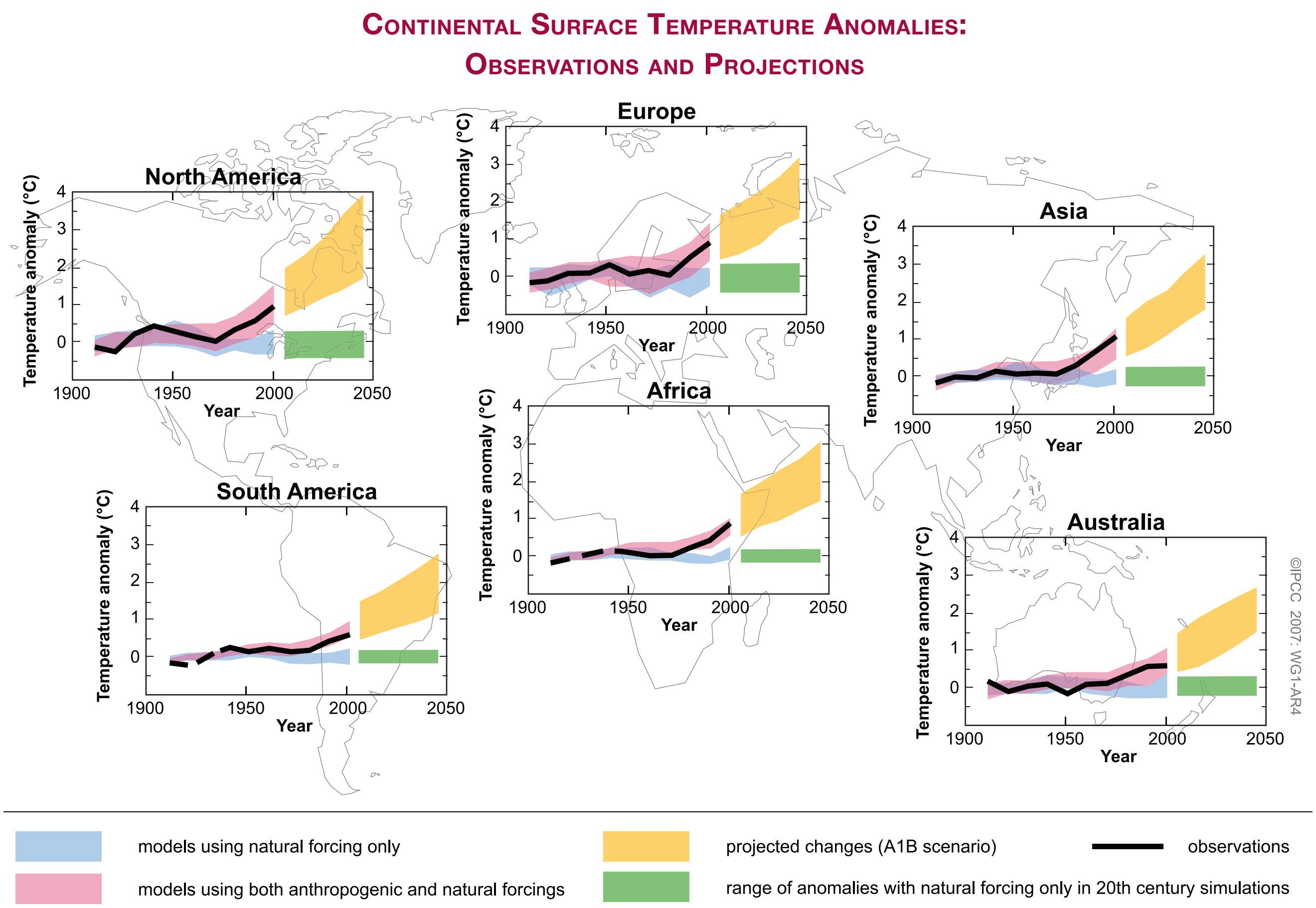


Figure TS.29. *Decadal mean continental surface temperature anomalies (°C) in observations and simulations for the period 1906 to 2005 and in projections for 2001 to 2050. Anomalies are calculated from the 1901 to 1950 average. The black lines represent the observations and the red and blue bands show simulated average temperature anomalies as in Figure TS.22 for the 20th century (i.e., red includes anthropogenic and natural forcings and blue includes only natural forcings). The yellow shading represents the 5th to 95th percentile range of projected changes according to the SRES A1B emissions scenario. The green bar denotes the 5th to 95th percentile range of decadal mean anomalies from the 20th-century simulations with only natural forcings (i.e., a measure of the natural decadal variability). For the observed part of these graphs, the decadal averages are centred on calendar decade boundaries (i.e., the last point is at 2000 for 1996 to 2005), whereas for the future period they are centred on calendar decade mid-points (i.e., the first point is at 2005 for 2001 to 2010). To construct the ranges, all simulations from the set of models involved were considered independent realisations of the possible evolution of the climate given the forcings applied. This involved 58 simulations from 14 models for the red curve, 19 simulations from 5 models (a subset of the 14) for the blue curve and green bar and 47 simulations from 18 models for the yellow curve. {FAQ 9.2.1, Figure 1 and Box 11.1, Figure 1}*

In the NH a robust pattern of increased subpolar and decreased subtropical precipitation dominates the projected precipitation pattern for the 21st century over North America and Europe, while subtropical drying is less evident over Asia (see Figure TS.30). Nearly all models project increased precipitation over most of northern North America and decreased precipitation over Central America, with much of the continental USA and northern Mexico in a more uncertain transition zone that moves north and south following the seasons. Decreased precipitation is confidently projected for southern Europe and Mediterranean Africa, with a transition to increased precipitation in northern Europe. In both continents, summer drying is extensive due both to the poleward movement of this transition zone in summer and to increased evaporation. Subpolar increases in precipitation are projected over much of northern Asia but with the subtropical drying spreading from the Mediterranean displaced by distinctive monsoonal signatures as one moves from central Asia eastward. {11.2–11.5}

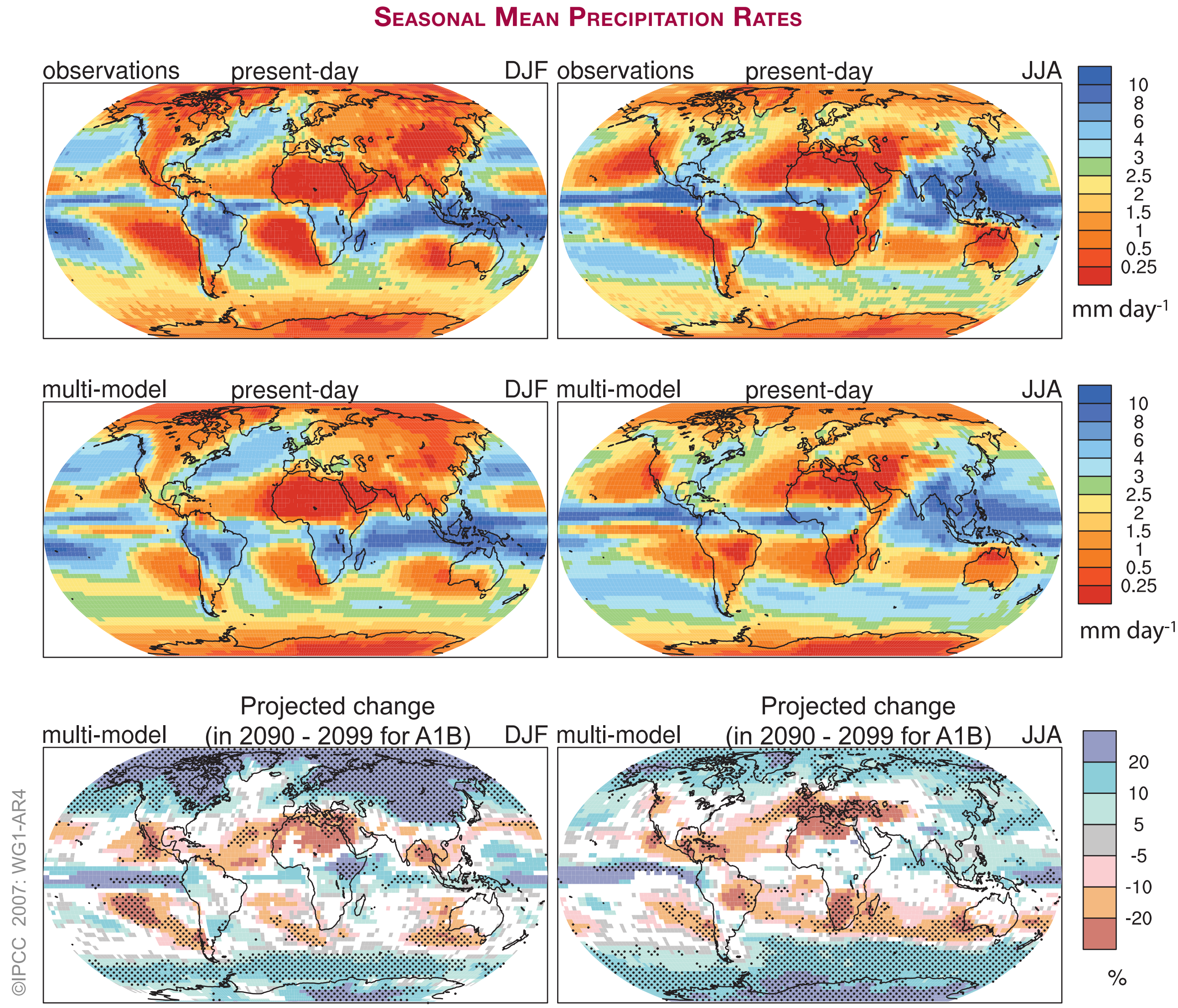


Figure TS.30. *Spatial patterns of observed (top row) and multi-model mean (middle row) seasonal mean precipitation rate (mm day^{-1}) for the period 1979 to 1993 and the multi-model mean for changes by the period 2090 to 2099 relative to 1980 to 1999 (% change) based on the SRES A1B scenario (bottom row). December to February means are in the left column, June to August means in the right column. In the bottom panel, changes are plotted only where more than 66% of the models agree on the sign of the change. The stippling indicates areas where more than 90% of the models agree on the sign of the change. {Based on same datasets as shown in Figures 8.5 and 10.9}*

In the SH, there are few land areas in the zone of projected subpolar moistening during the 21st century, with the subtropical drying more prominent (see Figure TS.30). The South Island of New Zealand and Tierra del Fuego fall within the subpolar precipitation increase zone, with southernmost Africa, the southern Andes in South America and southern Australia experiencing the drying tendency typical of the subtropics. {11.2, 11.6, 11.7}

Projections of precipitation over tropical land regions are more uncertain than those at higher latitudes, but, despite significant inadequacies in modelling tropical convection and atmosphere-ocean interactions, and the added uncertainty associated with tropical cyclones, some robust features emerge in models. Rainfall in the summer monsoon season of South and Southeast Asia increases in most models, as does rainfall in East Africa. The sign of the precipitation response is considered less certain over both the Amazon and the African Sahel. These are regions in which there is added uncertainty due to potential vegetation-climate links, and there is less robustness across models even when vegetation feedbacks are not included. {8.3, 11.2, 11.4, 11.6}

TS.5.4 Coupling Between Climate Change and Changes in Biogeochemical Cycles

All models that treat the coupling of the carbon cycle to climate change indicate a positive feedback effect with warming acting to suppress land and ocean uptake of CO_2, leading to larger atmospheric CO_2 increases and greater climate change for a given emissions scenario, but the strength of this feedback effect varies markedly among models. Since the TAR, several new projections based on fully coupled carbon cycle-climate models have been performed and compared. For the SRES A2 scenario, and based on a range of model results, the projected increase in atmospheric CO_2 concentration over the 21st century is *likely* between 10 and 25% higher than projections without this feedback, adding more than 1°C to projected mean warming by 2100 for higher emission SRES scenarios. Correspondingly, the reduced CO_2 uptake caused by this effect reduces the CO_2 emissions that are consistent with a target stabilisation level. However, there are still significant uncertainties due, for example, to limitations in the understanding of the dynamics of land ecosystems and soils. {7.3, 10.4}

Increasing atmospheric CO_2 concentrations lead directly to increasing acidification of the surface ocean. Projections based on SRES scenarios give reductions in pH of between 0.14 and 0.35 units in the 21st century (depending on scenario), extending the present decrease of 0.1 units from pre-industrial times. Ocean acidification would lead to dissolution of shallow-water carbonate sediments. Southern Ocean surface waters are projected to exhibit undersaturation with regard to calcium carbonate ($CaCO_3$) for CO_2 concentrations higher than 600 ppm, a level exceeded during the second half of the 21st century in most of the SRES scenarios. Low-latitude regions and the deep ocean will be affected as well. These changes could affect marine organisms that form their exoskeletons out of $CaCO_3$, but the net effect on the biological cycling of carbon in the oceans is not well understood. {Box 7.3, 10.4}

Committed climate change due to past emissions varies considerably for different forcing agents because of differing lifetimes in the Earth's atmosphere (see Box TS.9). The committed climate change due to past emissions takes account of both (i) the time lags in the responses of the climate system to changes in radiative forcing; and (ii) the time scales over which different forcing agents persist in the atmosphere after their emission because of their differing lifetimes. Typically the committed climate change due to past emissions includes an initial period of further increase in temperature, for the reasons discussed above, followed by a long-term decrease as radiative forcing decreases. Some greenhouse gases have relatively short atmospheric lifetimes (decades or less), such as CH_4 and carbon monoxide, while others such as N_2O have lifetimes of the order of a century, and some have lifetimes of millennia, such as SF_6 and PFCs. Atmospheric concentrations of CO_2 do not decay with a single well-defined lifetime if emissions are stopped. Removal of CO_2 emitted to the atmosphere occurs over multiple time scales, but some CO_2 will stay in the atmosphere for many thousands of years, so that emissions lead to a very long commitment to climate change. The slow long-term buffering of the ocean, including $CaCO_3$-sediment feedback, requires 30,000 to 35,000 years for atmospheric CO_2 concentrations to reach equilibrium. Using coupled carbon cycle components, EMICs show that the committed climate change due to past CO_2 emissions persists for more than 1000 years, so that even over these very long time scales, temperature and sea level do not return to pre-industrial values. An indication of the long time scales of committed climate change is obtained by prescribing anthropogenic CO_2 emissions following a path towards stabilisation at 750 ppm, but arbitrarily setting emissions to zero at year 2100. In this test case, it takes about 100 to 400 years in the different models for the atmospheric CO_2 concentration to drop from the maximum (ranges between 650 to 700 ppm) to below the level of two times the pre-industrial CO_2 concentration (about 560 ppm), owing to a continuous but slow transfer of carbon from the atmosphere and terrestrial reservoirs to the ocean (see Figure TS.31). {7.3, 10.7}

Future concentrations of many non-CO_2 greenhouse gases and their precursors are expected to be coupled to future climate change. Insufficient understanding of the causes of recent variations in the CH_4 growth rate suggests large uncertainties in future projections for this gas in particular. Emissions of CH_4 from wetlands are *likely* to increase in a warmer and wetter climate and to decrease in a warmer and drier climate. Observations also suggest increases in CH_4 released from northern peatlands that are experiencing permafrost melt, although the large-scale magnitude of this effect is not well quantified. Changes in temperature, humidity and clouds could also affect biogenic emissions of ozone precursors, such as volatile organic compounds. Climate change is also expected to affect tropospheric ozone through changes in chemistry and transport. Climate change could induce changes in OH through changes in humidity, and could alter stratospheric ozone concentrations and hence solar ultraviolet radiation in the troposphere. {7.4, 4.7}

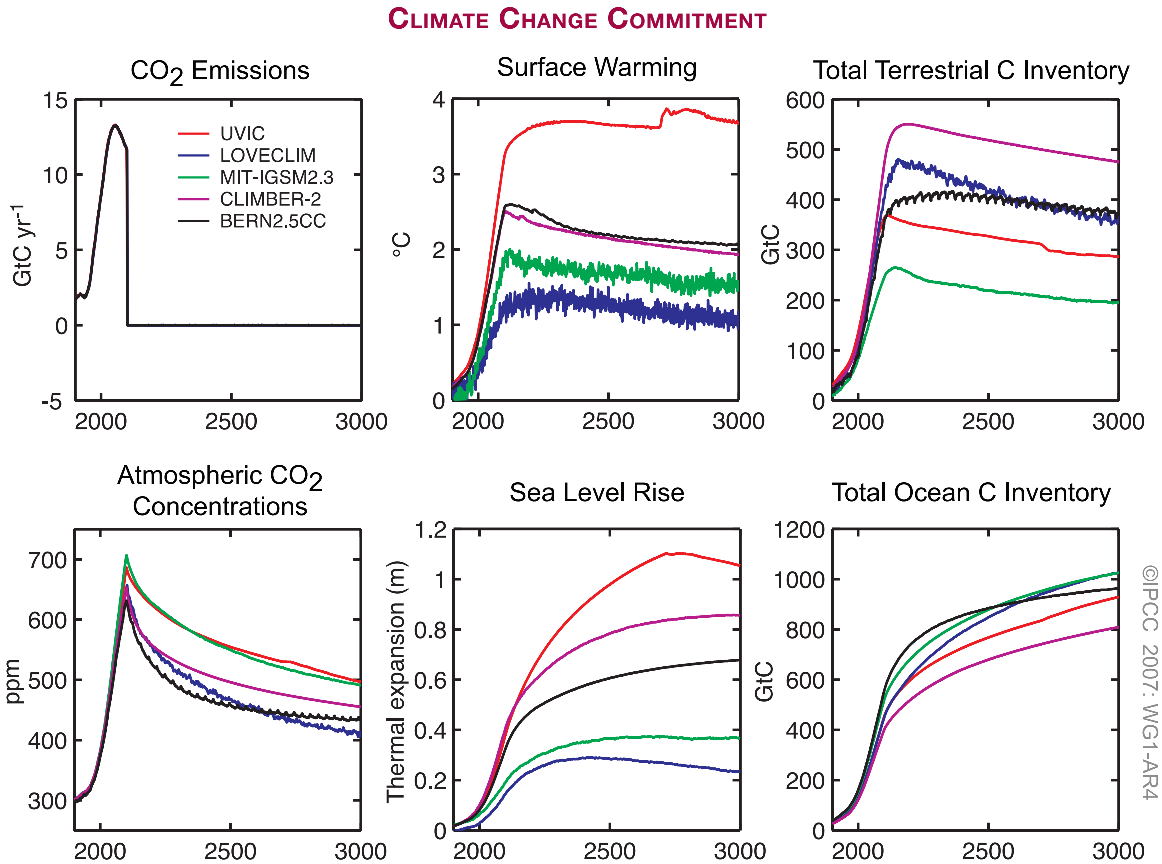


Figure TS.31. *Calculation of climate change commitment due to past emissions for five different EMICs and an idealised scenario where emissions follow a pathway leading to stabilisation of atmospheric CO_2 at 750 ppm, but before reaching this target, emissions are reduced to zero instantly at year 2100. (Left) CO_2 emissions and atmospheric CO_2 concentrations; (centre) surface warming and sea level rise due to thermal expansion; (right) change in total terrestrial and oceanic carbon inventory since the pre-industrial era. {Figure 10.35}*

Future emissions of many aerosols and their precursors are expected to be affected by climate change. Estimates of future changes in dust emissions under several climate and land use scenarios suggest that the effects of climate change are more important in controlling future dust emissions than changes in land use. Results from one study suggest that meteorology and climate have a greater influence on future Asian dust emissions and associated Asian dust storm occurrences than desertification. The biogenic emission of volatile organic compounds, a significant source of secondary organic aerosols, is known to be highly sensitive to (and increase with) temperature. However, aerosol yields decrease with temperature and the effects of changing precipitation and physiological adaptation are uncertain. Thus, change in biogenic secondary organic aerosol production in a warmer climate could be considerably lower than the response of biogenic volatile organic carbon emissions. Climate change may affect fluxes from the ocean of dimethyl sulphide (which is a precursor for some sulphate aerosols) and sea salt aerosols, however, the effects on temperature and precipitation remain very uncertain. {7.5}

While the warming effect of CO_2 represents a commitment over many centuries, aerosols are removed from the atmosphere over time scales of only a few days, so that the negative radiative forcing due to aerosols could change rapidly in response to any changes in emissions of aerosols or aerosol precursors. Because sulphate aerosols are *very likely* exerting a substantial negative radiative forcing at present, future net forcing is very sensitive to changes in sulphate emissions. One study suggests that the hypothetical removal from the atmosphere of the entire current burden of anthropogenic sulphate aerosol particles would produce a rapid increase in global mean temperature of about 0.8°C within a decade or two. Changes in aerosols are also likely to influence precipitation. Thus, the effect of environmental strategies aimed at mitigating climate change requires consideration of changes in both greenhouse gas and aerosol emissions.

Changes in aerosol emissions may result from measures implemented to improve air quality which may therefore have consequences for climate change. {Box 7.4, 7.6, 10.7}

Climate change would modify a number of chemical and physical processes that control air quality and the net effects are *likely* to vary from one region to another. Climate change can affect air quality by modifying the rates at which pollutants are dispersed, the rate at which aerosols and soluble species are removed from the atmosphere, the general chemical environment for pollutant generation and the strength of emissions from the biosphere, fires and dust. Climate change is also expected to decrease the global ozone background. Overall, the net effect of climate change on air quality is highly uncertain. {Box 7.4}

TS.5.5 Implications of Climate Processes and their Time Scales for Long-Term Projections

The commitments to climate change after stabilisation of radiative forcing are expected to be about 0.5 to 0.6°C, mostly within the following century. The multi-model average when stabilising concentrations of greenhouse gases and aerosols at year 2000 values after a 20th-century climate simulation, and running an additional 100 years, is about 0.6°C of warming (relative to 1980–1999) at year 2100 (see Figure TS.32). If the B1 or A1B scenarios were to characterise 21st-century emissions followed by stabilisation at those levels, the additional warming after stabilisation is similar, about 0.5°C, mostly in the subsequent hundred years. {10.3, 10.7}

The magnitude of the positive feedback between climate change and the carbon cycle is uncertain. This leads to uncertainty in the trajectory of CO_2 emissions required to achieve a particular stabilization level of atmospheric CO_2 concentration. Based upon current understanding of climate-carbon cycle feedback, model studies suggest that, in order to stabilise CO_2 at 450 ppm, cumulative emissions in the 21st century could be reduced from a model average of approximately 670 [630 to 710] GtC to approximately 490 [375 to 600] GtC. Similarly, to stabilise CO_2 at 1000 ppm, the cumulative emissions could be reduced by this feedback from a model average of

SRES Mean Surface Warming Projections

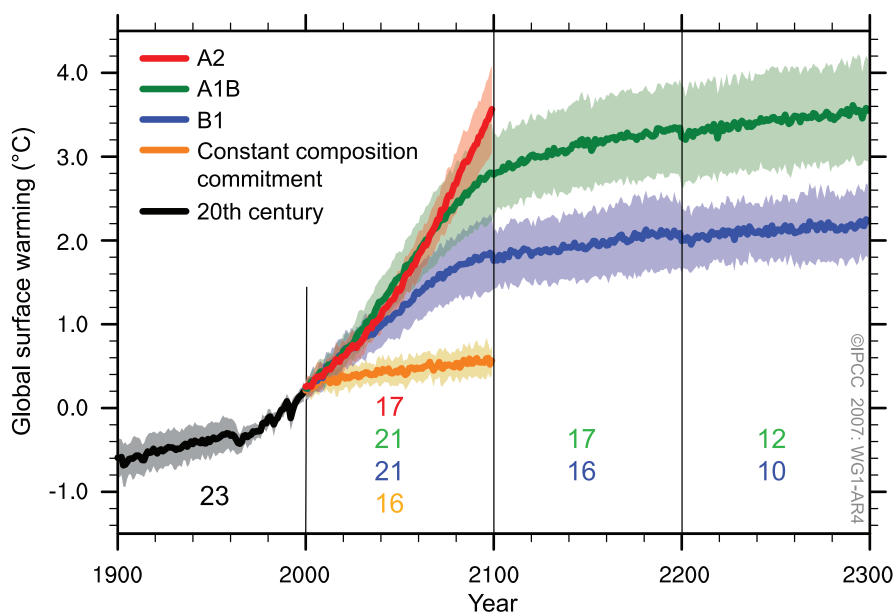


Figure TS.32. *Multi-model means of surface warming (compared to the 1980–1999 base period) for the SRES scenarios A2 (red), A1B (green) and B1 (blue), shown as continuations of the 20th-century simulation. The latter two scenarios are continued beyond the year 2100 with forcing kept constant (committed climate change as it is defined in Box TS.9). An additional experiment, in which the forcing is kept at the year 2000 level is also shown (orange). Linear trends from the corresponding control runs have been removed from these time series. Lines show the multi-model means, shading denotes the ±1 standard deviation range. Discontinuities between different periods have no physical meaning and are caused by the fact that the number of models that have run a given scenario is different for each period and scenario (numbers indicated in figure). For the same reason, uncertainty across scenarios should not be interpreted from this figure (see Section 10.5 for uncertainty estimates). {Figure 10.4}* approximately 1415 [1340 to 1490] GtC to approximately 1100 [980 to 1250] GtC. {7.3, 10.4}

If radiative forcing were to be stabilised in 2100 at A1B concentrations, thermal expansion alone would lead to 0.3 to 0.8 m of sea level rise by 2300 (relative to 1980–1999) and would continue at decreasing rates for many centuries, due to slow processes that mix heat into the deep ocean. {10.7}

Contraction of the Greenland Ice Sheet is projected to continue to contribute to sea level rise after 2100. For stabilisation at A1B concentrations in 2100, a rate of 0.03 to 0.21 m per century due to thermal expansion is projected. If a global average warming of 1.9°C to 4.6°C relative to pre-industrial temperatures were maintained for millennia, the Greenland Ice Sheet would largely be eliminated except for remnant glaciers in the mountains. This would raise sea level by about 7 m and could be irreversible. These temperatures are comparable to those inferred for the last interglacial period 125,000 years ago, when palaeoclimatic information suggests reductions of polar ice extent and 4 to 6 m of sea level rise. {6.4, 10.7}

Dynamical processes not included in current models but suggested by recent observations could increase the vulnerability of the ice sheets to warming, increasing future sea level rise. Understanding of these processes is limited and there is no consensus on their likely magnitude. {4.6, 10.7}

Current global model studies project that the Antarctic Ice Sheet will remain too cold for widespread surface melting and will gain in mass due to increased snowfall. However, net loss of ice mass could occur if dynamical ice discharge dominates the ice sheet mass balance. {10.7}

While no models run for this assessment suggest an abrupt MOC shutdown during the 21st century, some models of reduced complexity suggest MOC shutdown as a possible long-term response to sufficiently strong warming. However, the likelihood of this occurring cannot be evaluated with confidence. The few available simulations with models of different complexity rather suggest a centennial-scale slowdown. Recovery of the MOC is *likely* if the radiative forcing is stabilised but would take several centuries. Systematic model comparison studies have helped establish some key processes that are responsible for variations between models in the response of the ocean to climate change (especially ocean heat uptake). {8.7, FAQ 10.2, 10.3}

TS.6 Robust Findings and Key Uncertainties

TS.6.1 Changes in Human and Natural Drivers of Climate

Robust Findings:

Current atmospheric concentrations of CO_2 and CH_4, and their associated positive radiative forcing, far exceed those determined from ice core measurements spanning the last 650,000 years. {6.4}

Fossil fuel use, agriculture and land use have been the dominant cause of increases in greenhouse gases over the last 250 years. {2.3, 7.3, 7.4}

Annual emissions of CO_2 from fossil fuel burning, cement production and gas flaring increased from a mean of 6.4 ± 0.4 GtC yr^{-1} in the 1990s to 7.2 ± 0.3 GtC yr^{-1} for 2000 to 2005. {7.3}

The sustained rate of increase in radiative forcing from CO_2, CH_4 and N_2O over the past 40 years is larger than at any time during at least the past 2000 years. {6.4}

Natural processes of CO_2 uptake by the oceans and terrestrial biosphere remove about 50 to 60% of anthropogenic emissions (i.e., fossil CO_2 emissions and land use change flux). Uptake by the oceans and the terrestrial biosphere are similar in magnitude over recent decades but that by the terrestrial biosphere is more variable. {7.3}

It is *virtually certain* that anthropogenic aerosols produce a net negative radiative forcing (cooling influence) with a greater magnitude in the NH than in the SH. {2.9, 9.2}

From new estimates of the combined anthropogenic forcing due to greenhouse gases, aerosols and land surface changes, it is *extremely likely* that human activities have exerted a substantial net warming influence on climate since 1750. {2.9}

Solar irradiance contributions to global average radiative forcing are considerably smaller than the contribution of increases in greenhouse gases over the industrial period. {2.5, 2.7}

***Key Uncertainties*:**

The full range of processes leading to modification of cloud properties by aerosols is not well understood and the magnitudes of associated indirect radiative effects are poorly determined. {2.4, 7.5}

The causes of, and radiative forcing due to stratospheric water vapour changes are not well quantified. {2.3}

The geographical distribution and time evolution of the radiative forcing due to changes in aerosols during the 20th century are not well characterised. {2.4}

The causes of recent changes in the growth rate of atmospheric CH_4 are not well understood. {7.4}

The roles of different factors increasing tropospheric ozone concentrations since pre-industrial times are not well characterised. {2.3}

Land surface properties and land-atmosphere interactions that lead to radiative forcing are not well quantified. {2.5}

Knowledge of the contribution of past solar changes to radiative forcing on the time scale of centuries is not based upon direct measurements and is hence strongly dependent upon physical understanding. {2.7}

TS.6.2 Observations of Changes in Climate

TS.6.2.1 Atmosphere and Surface

Robust Findings:

Global mean surface temperatures continue to rise. Eleven of the last 12 years rank among the 12 warmest years on record since 1850. {3.2}

Rates of surface warming increased in the mid-1970s and the global land surface has been warming at about double the rate of ocean surface warming since then. {3.2}

Changes in surface temperature extremes are consistent with warming of the climate. {3.8}

Estimates of mid- and lower-tropospheric temperature trends have substantially improved. Lower-tropospheric temperatures have slightly greater warming rates than the surface from 1958 to 2005. {3.4}

Long-term trends from 1900 to 2005 have been observed in precipitation amount in many large regions. {3.3}

Increases have occurred in the number of heavy precipitation events. {3.8}

Droughts have become more common, especially in the tropics and subtropics, since the 1970s. {3.3}

Tropospheric water vapour has increased, at least since the 1980s. {3.4}

Key Uncertainties:

Radiosonde records are much less complete spatially than surface records and evidence suggests a number of radiosonde records are unreliable, especially in the tropics. It is likely that all records of tropospheric temperature trends still contain residual errors. {3.4}

While changes in large-scale atmospheric circulation are apparent, the quality of analyses is best only after 1979, making analysis of, and discrimination between, change and variability difficult. {3.5, 3.6}

Surface and satellite observations disagree on total and low-level cloud changes over the ocean. {3.4}

Multi-decadal changes in DTR are not well understood, in part because of limited observations of changes in cloudiness and aerosols. {3.2}

Difficulties in the measurement of precipitation remain an area of concern in quantifying trends in global and regional precipitation. {3.3}

Records of soil moisture and streamflow are often very short, and are available for only a few regions, which impedes complete analyses of changes in droughts. {3.3}

The availability of observational data restricts the types of extremes that can be analysed. The rarer the event, the more difficult it is to identify long-term changes because there are fewer cases available. {3.8}

Information on hurricane frequency and intensity is limited prior to the satellite era. There are questions about the interpretation of the satellite record. {3.8}

There is insufficient evidence to determine whether trends exist in tornadoes, hail, lightning and dust storms at small spatial scales. {3.8}

TS.6.2.2 Snow, Ice and Frozen Ground

Robust Findings:

The amount of ice on the Earth is decreasing. There has been widespread retreat of mountain glaciers since the end of the 19th century. The rate of mass loss from glaciers and the Greenland Ice Sheet is increasing. {4.5, 4.6}

The extent of NH snow cover has declined. Seasonal river and lake ice duration has decreased over the past 150 years. {4.2, 4.3}

Since 1978, annual mean arctic sea ice extent has been declining and summer minimum arctic ice extent has decreased. {4.4}

Ice thinning occurred in the Antarctic Peninsula and Amundsen shelf ice during the 1990s. Tributary glaciers have accelerated and complete breakup of the Larsen B Ice Shelf occurred in 2002. {4.6}

Temperature at the top of the permafrost layer has increased by up to 3°C since the 1980s in the Arctic. The maximum extent of seasonally frozen ground has decreased by about 7% in the NH since 1900, and its maximum depth has decreased by about 0.3 m in Eurasia since the mid-20th century. {4.7}

Key Uncertainties:

There is no global compilation of *in situ* snow data prior to 1960. Well-calibrated snow water equivalent data are not available for the satellite era. {4.2}

There are insufficient data to draw any conclusions about trends in the thickness of antarctic sea ice. {4.4}

Uncertainties in estimates of glacier mass loss arise from limited global inventory data, incomplete area-volume relationships and imbalance in geographic coverage. {4.5}

Mass balance estimates for ice shelves and ice sheets, especially for Antarctica, are limited by calibration and validation of changes detected by satellite altimetry and gravity measurements. {4.6}

Limited knowledge of basal processes and of ice shelf dynamics leads to large uncertainties in the understanding of ice flow processes and ice sheet stability. {4.6}

TS.6.2.3 Oceans and Sea Level

Robust Findings:

The global temperature (or heat content) of the oceans has increased since 1955. {5.2}

Large-scale regionally coherent trends in salinity have been observed over recent decades with freshening in subpolar regions and increased salinity in the shallower parts of the tropics and subtropics. These trends are consistent with changes in precipitation and inferred larger water transport in the atmosphere from low latitudes to high latitudes and from the Atlantic to the Pacific. {5.2}

Global average sea level rose during the 20th century. There is high confidence that the rate of sea level rise increased between the mid-19th and mid-20th centuries. During 1993 to 2003, sea level rose more rapidly than during 1961 to 2003. {5.5}

Thermal expansion of the ocean and loss of mass from glaciers and ice caps made substantial contributions to the observed sea level rise. {5.5}

The observed rate of sea level rise from 1993 to 2003 is consistent with the sum of observed contributions from thermal expansion and loss of land ice. {5.5}

The rate of sea level change over recent decades has not been geographically uniform. {5.5}

As a result of uptake of anthropogenic CO_2 since 1750, the acidity of the surface ocean has increased. {5.4, 7.3}

Key Uncertainties:

Limitations in ocean sampling imply that decadal variability in global heat content, salinity and sea level changes can only be evaluated with moderate confidence. {5.2, 5.5}

There is low confidence in observations of trends in the MOC. {Box 5.1}

Global average sea level rise from 1961 to 2003 appears to be larger than can be explained by thermal expansion and land ice melting. {5.5}

TS.6.2.4 Palaeoclimate

Robust Findings:

During the last interglacial, about 125,000 years ago, global sea level was *likely* 4 to 6 m higher than present, due primarily to retreat of polar ice. {6.4}

A number of past abrupt climate changes were *very likely* linked to changes in Atlantic Ocean circulation and affected the climate broadly across the NH. {6.4}

It is *very unlikely* that the Earth would naturally enter another ice age for at least 30,000 years. {6.4}

Biogeochemical and biogeophysical feedbacks have amplified climatic changes in the past. {6.4}

It is *very likely* that average NH temperatures during the second half of the 20th century were warmer than in any other 50-year period in the last 500 years and *likely* that this was also the warmest 50-year period in the past 1300 years. {6.6}

Palaeoclimate records indicate with high confidence that droughts lasting decades or longer were a recurrent feature of climate in several regions over the last 2000 years. {6.6}

Key Uncertainties:

Mechanisms of onset and evolution of past abrupt climate change and associated climate thresholds are not well understood. This limits confidence in the ability of climate models to simulate realistic abrupt change. {6.4}

The degree to which ice sheets retreated in the past, the rates of such change and the processes involved are not well known. {6.4}

Knowledge of climate variability over more than the last few hundred years in the SH and tropics is limited by the lack of palaeoclimatic records. {6.6}

Differing amplitudes and variability observed in available millennial-length NH temperature reconstructions, as well as the relation of these differences to choice of proxy data and statistical calibration methods, still need to be reconciled. {6.6}

The lack of extensive networks of proxy data for temperature in the last 20 years limits understanding of how such proxies respond to rapid global warming and of the influence of other environmental changes. {6.6}

TS.6.3 Understanding and Attributing Climate Change

Robust Findings:

Greenhouse gas forcing has *very likely* caused most of the observed global warming over the last 50 years. Greenhouse gas forcing alone during the past half century would *likely* have resulted in greater than the observed warming if there had not been an offsetting cooling effect from aerosol and other forcings. {9.4}

It is *extremely unlikely* (<5%) that the global pattern of warming during the past half century can be explained without external forcing, and *very unlikely* that it is due to known natural external causes alone. The warming occurred in both the ocean and the atmosphere and took place at a time when natural external forcing factors would *likely* have produced cooling. {9.4, 9.7}

It is *likely* that anthropogenic forcing has contributed to the general warming observed in the upper several hundred metres of the ocean during the latter half of the 20th century. Anthropogenic forcing, resulting in thermal expansion from ocean warming and glacier mass loss, has *very likely* contributed to sea level rise during the latter half of the 20th century. {9.5}

A substantial fraction of the reconstructed NH inter-decadal temperature variability of the past seven centuries is *very likely* attributable to natural external forcing (volcanic eruptions and solar variability). {9.3}

Key Uncertainties:

Confidence in attributing some climate change phenomena to anthropogenic influences is currently limited by uncertainties in radiative forcing, as well as uncertainties in feedbacks and in observations. {9.4, 9.5}

Attribution at scales smaller than continental and over time scales of less than 50 years is limited by larger climate variability on smaller scales, by uncertainties in the small-scale details of external forcing and the response simulated by models, as well as uncertainties in simulation of internal variability on small scales, including in relation to modes of variability. {9.4}

There is less confidence in understanding of forced changes in precipitation and surface pressure than there is of temperature. {9.5}

The range of attribution statements is limited by the absence of formal detection and attribution studies, or their very limited number, for some phenomena (e.g., some types of extreme events). {9.5}

Incomplete global data sets for extremes analysis and model uncertainties still restrict the regions and types of detection studies of extremes that can be performed. {9.4, 9.5}

Despite improved understanding, uncertainties in model-simulated internal climate variability limit some aspects of attribution studies. For example, there are apparent discrepancies between estimates of ocean heat content variability from models and observations. {5.2, 9.5}

Lack of studies quantifying the contributions of anthropogenic forcing to ocean heat content increase or glacier melting together with the open part of the sea level budget for 1961 to 2003 are among the uncertainties in quantifying the anthropogenic contribution to sea level rise. {9.5}

TS.6.4 Projections of Future Changes in Climate

TS.6.4.1 Model Evaluation

Robust Findings:

Climate models are based on well-established physical principles and have been demonstrated to reproduce observed features of recent climate and past climate changes. There is considerable confidence that AOGCMs provide credible quantitative estimates of future climate change, particularly at continental scales and above. Confidence in these estimates is higher for some climate variables (e.g., temperature) than for others (e.g., precipitation). {FAQ 8.1}

Confidence in models has increased due to:

- improvements in the simulation of many aspects of present climate, including important modes of climate variability and extreme hot and cold spells;
- improved model resolution, computational methods and parametrizations and inclusion of additional processes;
- more comprehensive diagnostic tests, including tests of model ability to forecast on time scales from days to a year when initialised with observed conditions; and
- enhanced scrutiny of models and expanded diagnostic analysis of model behaviour facilitated by internationally coordinated efforts to collect and disseminate output from model experiments performed under common conditions. {8.4}

Key Uncertainties:

A proven set of model metrics comparing simulations with observations, that might be used to narrow the range of plausible climate projections, has yet to be developed. {8.2}

Most models continue to have difficulty controlling climate drift, particularly in the deep ocean. This drift must be accounted for when assessing change in many oceanic variables. {8.2}

Models differ considerably in their estimates of the strength of different feedbacks in the climate system. {8.6}

Problems remain in the simulation of some modes of variability, notably the Madden-Julian Oscillation, recurrent atmospheric blocking and extreme precipitation. {8.4}

Systematic biases have been found in most models' simulations of the Southern Ocean that are linked to uncertainty in transient climate response. {8.3}

Climate models remain limited by the spatial resolution that can be achieved with present computer resources, by the need for more extensive ensemble runs and by the need to include some additional processes. {8.1–8.5}

TS.6.4.2 Equilibrium and Transient Climate Sensitivity

Robust Findings:

Equilibrium climate sensitivity is *likely* to be in the range 2°C to 4.5°C with a most likely value of about 3°C, based upon multiple observational and modelling constraints. It is *very unlikely* to be less than 1.5°C. {8.6, 9.6, Box 10.2}

The transient climate response is better constrained than the equilibrium climate sensitivity. It is *very likely* larger than 1°C and *very unlikely* greater than 3°C. {10.5}

There is a good understanding of the origin of differences in equilibrium climate sensitivity found in different models. Cloud feedbacks are the primary source of inter-model differences in equilibrium climate sensitivity, with low cloud being the largest contributor. {8.6}

New observational and modelling evidence strongly supports a combined water vapour-lapse rate feedback of a strength comparable to that found in AOGCMs. {8.6}

Key Uncertainties:

Large uncertainties remain about how clouds might respond to global climate change. {8.6}

TS.6.4.3 Global Projections

Robust Findings:

Even if concentrations of radiative forcing agents were to be stabilised, further committed warming and related climate changes would be expected to occur, largely because of time lags associated with processes in the oceans. {10.7}

Near-term warming projections are little affected by different scenario assumptions or different model sensitivities, and are consistent with that observed for the past few decades. The multi-model mean warming, averaged over 2011 to 2030 relative to 1980 to 1999 for all AOGCMs considered here, lies in a narrow range of 0.64°C to 0.69°C for the three different SRES emission scenarios B1, A1B and A2. {10.3}

Geographic patterns of projected warming show the greatest temperature increases at high northern latitudes and over land, with less warming over the southern oceans and North Atlantic. {10.3}

Changes in precipitation show robust large-scale patterns: precipitation generally increases in the tropical precipitation maxima, decreases in the subtropics and increases at high latitudes as a consequence of a general intensification of the global hydrological cycle. {10.3}

As the climate warms, snow cover and sea ice extent decrease; glaciers and ice caps lose mass and contribute to sea level rise. Sea ice extent decreases in the 21st century in both the Arctic and Antarctic. Snow cover reduction is accelerated in the Arctic by positive feedbacks and widespread increases in thaw depth occur over much of the permafrost regions. {10.3}

Based on current simulations, it is *very likely* that the Atlantic Ocean MOC will slow down by 2100. However, it is *very unlikely* that the MOC will undergo a large abrupt transition during the course of the 21st century. {10.3}

Heat waves become more frequent and longer lasting in a future warmer climate. Decreases in frost days are projected to occur almost everywhere in the mid- and high latitudes, with an increase in growing season length. There is a tendency for summer drying of the mid-continental areas during summer, indicating a greater risk of droughts in those regions. {10.3, FAQ 10.1}

Future warming would tend to reduce the capacity of the Earth system (land and ocean) to absorb anthropogenic CO_2. As a result, an increasingly large fraction of anthropogenic CO_2 would stay in the atmosphere under a warmer climate. This feedback requires reductions in the cumulative emissions consistent with stabilisation at a given atmospheric CO_2 level compared to the hypothetical case of no such feedback. The higher the stabilisation scenario, the larger the amount of climate change and the larger the required reductions. {7.3, 10.4}

Key Uncertainties:

The likelihood of a large abrupt change in the MOC beyond the end of the 21st century cannot yet be assessed reliably. For low and medium emission scenarios with atmospheric greenhouse gas concentrations stabilised beyond 2100, the MOC recovers from initial weakening within one to several centuries. A permanent reduction in the MOC cannot be excluded if the forcing is strong and long enough. {10.7}

The model projections for extremes of precipitation show larger ranges in amplitude and geographical locations than for temperature. {10.3, 11.1}

The response of some major modes of climate variability such as ENSO still differs from model to model, which may be associated with differences in the spatial and temporal representation of present-day conditions. {10.3}

The robustness of many model responses of tropical cyclones to climate change is still limited by the resolution of typical climate models. {10.3}

Changes in key processes that drive some global and regional climate changes are poorly known (e.g., ENSO, NAO, blocking, MOC, land surface feedbacks, tropical cyclone distribution). {11.2–11.9}

The magnitude of future carbon cycle feedbacks is still poorly determined. {7.3, 10.4}

TS.6.4.4 Sea Level

Robust Findings:

Sea level will continue to rise in the 21st century because of thermal expansion and loss of land ice. Sea level rise was not geographically uniform in the past and will not be in the future. {10.6}

Projected warming due to emission of greenhouse gases during the 21st century will continue to contribute to sea level rise for many centuries. {10.7}

Sea level rise due to thermal expansion and loss of mass from ice sheets would continue for centuries or millennia even if radiative forcing were to be stabilised. {10.7}

Key Uncertainties:

Models do not yet exist that address key processes that could contribute to large rapid dynamical changes in the Antarctic and Greenland Ice Sheets that could increase the discharge of ice into the ocean. {10.6}

The sensitivity of ice sheet surface mass balance (melting and precipitation) to global climate change is not well constrained by observations and has a large spread in models. There is consequently a large uncertainty in the magnitude of global warming that, if sustained, would lead to the elimination of the Greenland Ice Sheet. {10.7}

TS.6.4.5 Regional Projections

Robust Findings:

Temperatures averaged over all habitable continents and over many sub-continental land regions will *very likely* rise at greater than the global average rate in the next 50 years and by an amount substantially in excess of natural variability. {10.3, 11.2–11.9}

Precipitation is *likely* to increase in most subpolar and polar regions. The increase is considered especially robust, and *very likely* to occur, in annual precipitation in most of northern Europe, Canada, the northeast USA and the Arctic, and in winter precipitation in northern Asia and the Tibetan Plateau. {11.2–11.9}

Precipitation is *likely* to decrease in many subtropical regions, especially at the poleward margins of the subtropics. The decrease is considered especially robust, and *very likely* to occur, in annual precipitation in European and African regions bordering the Mediterranean and in winter rainfall in south-western Australia. {11.2–11.9}

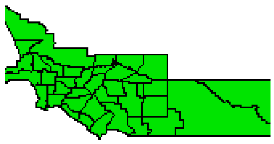
Extremes of daily precipitation are *likely* to increase in many regions. The increase is considered as *very likely* in northern Europe, south Asia, East Asia, Australia and New Zealand – this list in part reflecting uneven geographic coverage in existing published research. {11.2–11.9}

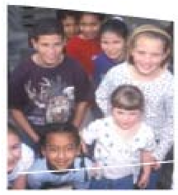
Key Uncertainties:

In some regions there has been only very limited study of key aspects of regional climate change, particularly with regard to extreme events. {11.2–11.9}

Atmosphere-Ocean General Circulation Models show no consistency in simulated regional precipitation change in some key regions (e.g., northern South America, northern Australia and the Sahel). {10.3, 11.2–11.9}

In many regions where fine spatial scales in climate are generated by topography, there is insufficient information on how climate change will be expressed at these scales. {11.2–11.9}





BOARD MEETING DATE: December 5, 2008
AGENDA NO. 31

PROPOSAL:

Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans

SYNOPSIS:

This action is to adopt a resolution approving the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules, and Plans where AQMD is the lead agency. This interim threshold will be used for determining significant impacts for proposed projects. Once CARB adopts the statewide significance thresholds, staff will report back to the Board regarding any recommended changes or additions to the AQMD's interim threshold.

COMMITTEE:

Climate Change, September 19, 2008 and October 29 2008

RECOMMENDED ACTIONS:

Adopt the attached resolution approving the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules, and Plans for use by the AQMD.

Barry R. Wallerstein, D.Env.
Executive Officer

Background

The California Environmental Quality Act (CEQA) requires public agencies in California to analyze potential adverse impacts from proposed projects undertaken by a public agency, funded by a public agency, or requiring discretionary approval by a public agency. To disclose potential adverse impacts from a proposed project, pursuant to CEQA, lead agencies typically prepare a multidisciplinary environmental impact analysis and make decisions based on the analysis regarding the environmental effects of the proposed project (CEQA Guidelines §15002[a]).

In the past, air quality analyses tended to focus on potential adverse impacts from criteria pollutants and toxic air contaminants. Subsequent to the adoption of Assembly Bill (AB) 32 - The California Global Warming Solutions Act of 2006, lead agencies have increasingly faced legal challenges to their CEQA documents for failure to analyze greenhouse gases (GHGs) or failure to make a determination of significance regarding GHG emission impacts.

Subsequent to the adoption of AB 32, there had been little regulatory guidance with regard to analyzing GHG emission impacts in CEQA documents until the Governor's Office of Planning and Research (OPR) released its Technical Advisory on CEQA and Climate Change (June 19, 2008). Consistent with Senate Bill (SB) 97, OPR's Technical Advisory was developed in cooperation with the Resources Agency, the California Environmental Protection Agency (Cal/EPA), and the California Air Resources Board (CARB). According to OPR, the Technical Advisory offers informal interim guidance regarding the steps lead agencies should take to address climate change in their CEQA documents, until CEQA guidelines are developed pursuant to SB 97 on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions.

This page update Novem 26, 2008 URL: http://

Because of its expertise in establishing air quality analysis methodologies and comprehensive efforts to establish regional and localized significance thresholds for criteria pollutants, local public agencies have asked the AQMD for guidance in quantifying GHG impacts and recommending GHG significance thresholds to assist them with determining whether or not GHG impacts in their CEQA documents are significant. In response to these requests from the various stakeholders, AQMD established a stakeholder working group to receive input on establishing a GHG significance threshold. In the meantime, AQMD staff has joined many other stakeholders urging CARB to establish a statewide threshold for GHGs. AQMD has been making GHG significance determinations for its CEQA documents on a case-by-case basis. Staff believes it is more prudent to make GHG significance determinations using a GHG significance threshold that has gone through a public process and has been adopted by resolution by the Board than making GHG significance determinations on a case-by-case basis. In the absence of a statewide threshold, AQMD staff recommends its interim approach to the Board for consideration and it will also become part of the AQMD's input to the statewide process. The interim GHG significance threshold proposal recommended by staff to the Board that applies only to industrial (stationary source) projects where the AQMD is the lead agency is a narrower recommendation than the version presented at the October 29, 2008 Climate Change Committee meeting.

GHG Working Group – The GHG significance threshold Working Group was formed to assist staff's efforts to develop an interim GHG significance threshold and is comprised of a wide variety of stakeholders including: state agencies, OPR, CARB, and the Attorney General's Office; local agencies, city and county planning departments, utilities such as sanitation and power, etc.; regulated stakeholders, industry and industry groups; and organizations, both environmental and professional. Working group meetings are also open to the public. Part of the purpose of the Working Group is to provide a forum to solicit comments and suggestions from the various stakeholders to assist AQMD staff with developing an interim GHG significance threshold that is consistent with CEQA requirements for developing significance thresholds, is supported by substantial evidence, and provides guidance to CEQA practitioners with regard to determining whether GHG emissions from a proposed project are significant. Since April 2008, seven Working Group meetings have been held. Detailed information on the GHG Working Group process is contained in Attachment E to this Board letter – *Draft Guidance Document – Interim Greenhouse Gas (GHG) Significance Threshold*. The staff-proposed interim GHG significance threshold resulting from the Working Group process is described later in this Board letter.

Legal Authority

CEQA Guidelines §15022(a) states that a public agency shall adopt objectives, criteria, and specific procedures consistent with CEQA and these [State] Guidelines for administering its responsibilities under CEQA. CEQA Guidelines §15022(d) states further, "In adopting procedures to implement CEQA, a public agency may adopt the State CEQA Guidelines through incorporation by reference. The agency may then adopt only those specific procedures or provisions described in subsection [15022] (a) which are necessary to tailor the general provisions of the guidelines to the specific operations of the agency." AQMD previously adopted the state guidelines and has since adopted specific provisions such as regional and localized are quality significance thresholds. Adopting GHG significance thresholds would be consistent with the CEQA Guidelines §15022 provision to tailor a public agency's implementing guidelines by adopting criteria relative to the specific operations of the AQMD.

Specifically with regard to thresholds of significance, CEQA Guidelines §15064.7(a) states, "Each public agency is encouraged to develop and publish thresholds of significance that the agency uses in the determination of the significance of environmental effects." Subsection (b) of the same section states further, "Thresholds of significance to be adopted for general use as part of the lead agency's environmental review process must be adopted by ordinance, resolution, rule or regulation, and developed through a public review process and be supported by substantial evidence." Staff's recommended GHG significance threshold has undergone a public review process as part of stakeholder working group meetings that are open to the public. The currently proposed interim GHG significance threshold will be for projects where the AQMD is the lead agency.

Proposal

Policy Objective – The overarching policy objective with regard to establishing a GHG significance threshold for the purposes of analyzing GHG impacts pursuant to CEQA is to establish a performance standard or target GHG reduction objective that will ultimately contribute to reducing GHG emissions to stabilize climate change. Full implementation of the Governor's Executive Order S-3-05 would reduce GHG emissions 80 percent below 1990 levels or 90 percent below current levels by 2050. It is anticipated that achieving the Executive Order's objective would contribute to worldwide efforts to cap GHG concentrations at 450 ppm, thus, stabilizing global climate.

As described below, staff's recommended interim GHG significance threshold proposal uses a tiered approach to determining significance. Tier 3, which is expected to be the primary tier by which the AQMD will determine significance for projects where it is the lead agency, uses the Executive Order S-3-05 goal as the basis for deriving the screening level. To avoid hindering attaining this goal, new or modified projects will need to be analyzed under CEQA and mitigated to the maximum extent feasible. Specifically, the Tier 3 screening level for stationary sources is based on an emission capture rate of 90 percent for all new or modified projects. A 90 percent emission capture rate means that 90 percent of total emissions from all new or modified stationary source projects would be subject to a CEQA analysis, including a negative declaration, a mitigated negative declaration, or an environmental impact report, which includes analyzing feasible alternatives and imposing feasible mitigation measures.

Therefore, the policy objective of staff's recommended interim GHG significance threshold proposal is to achieve an emission capture rate of 90 percent of all new or modified stationary source projects. A GHG significance threshold based on a 90 percent emission capture rate may be more appropriate to address the long-term adverse impacts associated with global climate change because most projects will be required to implement GHG reduction measures. Further, a 90 percent emission capture rate sets the emission threshold low enough to capture a substantial fraction of future stationary source projects that will be constructed to accommodate future statewide population and economic growth, while setting the emission threshold high enough to exclude small projects that will in aggregate contribute a relatively small fraction of the cumulative statewide GHG emissions. This assertion is based on the fact that staff estimates that these GHG emissions would account for slightly less than one percent of future 2050 statewide GHG emissions target (85 MMTCO2eq/yr). In addition, these small projects may be subject to future applicable GHG control regulations that would further reduce their overall future contribution to the statewide GHG inventory. Finally, these small sources are already subject to BACT for criteria pollutants and are more likely to be single-permit facilities, so they are more likely to have few opportunities readily available to reduce GHG emissions from other parts of their facility.

Staff does not believe a zero threshold, as recommended by some working group members would be feasible to implement. A 90 percent emissions capture rate will assure that all feasible GHG reduction measures will be implemented for a large majority of emissions from new or modified GHG stationary sources, while avoiding overwhelming the AQMD's capabilities to process environmental documents. Implementing the interim GHG significance threshold is expected to at least double or triple the number of CEQA documents for permit application projects that are prepared by the AQMD each year (from approximately 10 to 15 to more than 45). Based on the number of permit applications received per year, it is likely that a zero GHG significance threshold would require preparing hundreds of additional CEQA documents per year with minimal additional environmental benefits.

Applicability – At this time, staff is recommending consideration of an interim GHG significance threshold that would apply to stationary source/industrial projects where the AQMD is the lead agency under CEQA. The types of projects that the staff proposal would apply to include: AQMD rules, rule amendments, and plans, e.g., Air Quality Management Plans. In addition, the AQMD may be the lead agency under CEQA for projects that require discretion approval, i.e., projects that require discretionary air quality permits from the AQMD. It should be noted that stationary source equipment associated with these projects are either at BACT or must comply with source-specific rules that reduce criteria pollutants and/or air toxics.

Emission Calculations and Significance Threshold Proposal – For the purposes of determining whether or not GHG emissions from affected projects are significant, project emissions will include direct, indirect, and, to the extent information is available, life cycle emissions during construction and operation. Construction emissions will be amortized over the life of the project, defined as 30 years, added to the operational emissions, and compared to the applicable interim GHG significance threshold tier. The following bullet points describe the basic structure of staff's tiered GHG significance threshold proposal for stationary sources.

- **Tier 1** – consists of evaluating whether or not the project qualifies for any applicable exemption under CEQA. For example, SB 97 specifically exempts a limited number of projects until it expires in 2010. If the project qualifies for an exemption, no further action is required. If the project does not qualify for an exemption, then it would move to the next tier.

- **Tier 2** – consists of determining whether or not the project is consistent with a GHG reduction plan that may be part of a local general plan, for example. The concept embodied in this tier is equivalent to the existing concept of consistency in CEQA Guidelines §§15064(h)(3), 15125(d), or 15152(a). The GHG reduction plan must, at a minimum, comply with AB 32 GHG reduction goals; include emissions estimates agreed upon by either CARB or the AQMD, have been analyzed under CEQA, and have a certified Final CEQA document. Further, the GHG reduction plan must include a GHG emissions inventory tracking mechanism; process to monitor progress in achieving GHG emission reduction targets, and a commitment to remedy the excess emissions if GHG reduction goals are not met (enforcement).

  If the proposed project is consistent with the qualifying local GHG reduction plan, it is not significant for GHG emissions. If the project is not consistent with a local GHG reduction plan, there is no approved plan, or the GHG reduction plan does not include all of the components described above, the project would move to Tier 3.

- **Tier 3** – establishes a screening significance threshold level to determine significance using a 90 percent emission capture rate approach as described above.

  The 90 percent capture rate GHG significance screening level in Tier 3 for stationary sources was derived using the following methodology. Using AQMD's Annual Emission Reporting (AER) Program staff compiled reported annual natural gas consumption for

1,297 permitted facilities for 2006 through 2007 and rank-ordered the facilities to estimate the 90th percentile of the cumulative natural gas usage for all permitted facilities. Approximately 10 percent of facilities evaluated comprise more than 90 percent of the total natural gas consumption, which corresponds to 10,000 metric tons of CO2 equivalent emissions per year (MTCO2eq/yr) (the majority of combustions emissions is comprised of CO2). This value represents a boiler with a rating of approximately 27 million British thermal units per hour (mmBtu/hour) of heat input, operating at a 80 percent capacity factor. It should be noted that this analysis did not include other possible GHG pollutants such as methane, N2O; a life-cycle analysis; mobile sources; or indirect electricity consumption. Therefore, when implemented, staff's recommended interim proposal is expected to capture more than 90 percent of GHG emissions from stationary source projects.

If the project exceeds the GHG screening significance threshold level and GHG emissions cannot be mitigated to less than the screening level, the project would move to Tier 4.

- **Tier 4** – consists of a decision tree approach that allows the lead agency to choose one of three compliance options based on performance standards. *(For the purposes of Board consideration, Tier 4 is not recommended for approval at this time.)*

  The purpose of Tier 4 is to provide a means of determining significance relative to GHG emissions for very large projects that include design features and or other measures to mitigate GHG emissions to the maximum extent feasible, but residual GHG emissions still exceed the interim Tier 3 screening levels. In this situation, since no additional project-related GHG emission reductions are feasible, staff is considering whether it is reasonable to consider that residual emissions are not significant. The intent of the Tier 4 compliance options is to encourage large projects to implement the maximum feasible GHG reduction measures instead of shifting to multiple smaller projects that may forego some design efficiencies that can more easily be incorporated into large projects than small projects. CARB's interim GHG significance threshold proposal incorporates a similar, but modified approach for determining GHG significance along with other suggested approaches that may have merit to consider and incorporate into AQMD staff's recommended interim proposal. There are also policy and legal questions that need to be further resolved before adopting such an approach.

- **Tier 5** – under this tier, the project proponent would implement offsite mitigation (GHG reduction projects) to reduce GHG emission impacts to less than the proposed screening level. Any offsite mitigation measures that include purchase of offsets would require the project proponent provide offsets for the life of the project, which is defined as 30 years. If the project proponent is unable to implement offsite GHG reduction mitigation measures to reduce GHG emission impacts to less than the screening level, then GHG emissions from the project would be considered significant. Since it is currently uncertain how offsite mitigation measures, including purchased offsets, interact with future AB 32 Scoping Plan measures, the AQMD would allow substitution of mitigation measures that include an enforceable commitment to provide mitigation prior to the occurrence of emissions. The intent of this provision is to prevent mitigating the same emissions twice.

Mitigation Preference – If a project generates significant adverse impacts, CEQA Guidelines §15126.4 requires identification of mitigation measures to minimize potentially significant impacts. Because GHG emissions contribute to global change, mitigation measures could be implemented locally, nationally, or internationally and still provide global climate change benefits. Because reducing GHG emissions may provide co-benefits through concurrent reductions in criteria pollutants, when considering mitigation measures when the AQMD is the lead agency under CEQA, staff recommends that mitigation measures that are real, quantifiable, verifiable, and surplus be selected in the following order of preference.

- Incorporate GHG reduction features into the project design, e.g., increase a boiler's energy efficiency, use materials with a lower global warming potential than conventional materials, etc.
- Implement onsite measures that provide direct GHG emission reductions onsite, e.g., replace onsite combustion equipment (boilers, heaters, steam generators, etc.) with more efficient combustion equipment, install solar panels on the roof, eliminate or minimize fugitive emissions, etc.
- Implement neighborhood mitigation measure projects that could include installing solar power, increasing energy efficiency through replacing low efficiency water heaters with high efficiency water heaters, increasing building insulation, using fluorescent bulbs, replacing old inefficient refrigerators with efficient refrigerators using low global warming potential refrigerants, etc.
- Implement in-district mitigation measures such as any of the above identified GHG reduction measures; reducing vehicle miles traveled (VMT) through greater rideshare incentives, transit improvements, etc.
- Implement in-state mitigation measures, which could include any of the above measures.
- Implement out of state mitigation measure projects, which may include purchasing offsets if other options are not feasible.

GHG Significance Threshold Components Deferred to the Future

Tier 4 Performance Standards - Based on reasons stated earlier, staff recommends that further evaluation be conducted to address comments raised and to consider other approaches as appropriate. Specifically, CARB staff proposed a hybrid approach in their Draft Proposal that combines the AQMD's Tier 3 and Tier 4 concepts for stationary source projects. If CARB's board does not take final action on their interim GHG significance threshold proposal by February 2009, AQMD staff will report back in the following month regarding the viability of the Tier 4 performance standards and recommended actions, if any.

Residential/Commercial Sectors GHG Significance Threshold - To achieve the same policy objective of capturing 90 percent of GHG emissions from new development projects in the residential/commercial sectors and implement a "fair share" approach to reducing emission increases from each sector, staff discussed with the working group a proposal combining performance standards and screening thresholds. The performance standards primarily focus on energy efficiency measures beyond Title 24 and a screening level of 3,000 MTCO2eq/yr based on the relative GHG emissions contribution between residential/commercial sectors and stationary source (industrial) sectors. Additional analysis is needed to further define the performance standards and to coordinate with CARB staff's interim GHG proposal. Staff, therefore, recommends bringing this item back to the Board for discussion and possible action in March 2009 if the CARB board does not take its final action by February 2009.

A comparison between CARB staff's initial concepts and AQMD staff's recommended interim GHG significance threshold proposal for stationary projects and approaches for residential/commercial sectors is summarized in Table 1 for reference. A more detailed discussion is contained in the Draft Guidance Document in Attachment E.

Table 1
Comparison of CARB's and AQMD Staff's
Interim GHG Significance Threshold Approaches

Stationary/Industrial Sector Projects		
CARB		AQMD

Policy Objective	Capture 90% of statewide stationary project emissions	Capture 90% of district wide GHG emissions (industrial)
Exemption	Apply applicable exemption	Apply applicable exemption
Regional GHG Reduction Plan	N.A.	Project Consistent with Applicable GHG Reduction Plan with GHG inventorying, monitoring, enforcement, etc.
Thresholds	Project < 7,000 MTCO2eq/yr & meets construction & transportation performance standards	GHG emissions from industrial project is < 10,000 MTCO2eq/yr, includes construction emissions amortized over 30 years & added to operational GHG emissions
Performance Standards	See above	N.A.
Offsets	Offsite substitution allowed	Implement offsite mitigation for life of project, i.e., 30 years, with mitigation preference
Determination	GHG emissions significant, EIR is prepared, if meeting none of the above	GHG emissions significant, EIR is prepared, if meeting none of the above

Since not recommending specific GHG significance thresholds for residential/commercial sectors at this time, staff will perform its intergovernmental review (IGR) commenting function as a commenting and responsible agency by providing technical assistance in quantifying GHG emissions and making reference materials available to lead agencies. Reference materials from organizations other than AQMD may include the following:

- CAPCOA's *CEQA and Climate Change* white paper,
- CARB's Interim GHG significance threshold proposal, and

Future Activities – To assist other public agencies and CEQA practitioners with preparing a scientifically sound GHG analysis as part of preparing a CEQA document, staff will perform surveys of available data bases to compile GHG emission factors for as many GHG emission sources as possible. Staff has already compiled CO2 and methane emission factors for on-road and off-road mobile sources. Other GHG emission factors would be compiled and listed on the AQMD's CEQA webpages.

In addition to compiling GHG emission factors, staff will compile GHG mitigation measures to the extent specific measures with GHG control efficiencies are available. Mitigation measures will be compiled by source category and uploaded to the AQMD's CEQA webpages. Staff will continue the stakeholder working group process to seek input from working group members.

Finally, to further evaluate and refine the interim GHG significance threshold for residential/commercial projects and evaluate the compliance options in Tier 4, staff will participate in the statewide efforts and continue to work with stakeholders.

Resource Impacts

The AQMD periodically carries out the role of lead agency for permit application projects that have the potential to generate significant adverse impacts. On average, AQMD staff prepares 10 – 15 CEQA documents per year for permit application projects. In addition, all new and amended AQMD rules and regulations and Plans, e.g., Air Quality Management Plan, are evaluated for CEQA applicability and CEQA documents are prepared as necessary. If AQMD staff's proposed interim screening threshold of 10,000 MTCO2eq./yr is implemented, based on the permitting activities for 2006-2007 it will result in at least 31 additional CEQA documents per year, either MNDs or EIRs, being prepared by the AQMD as the lead agency unless another tier option is selected to demonstrate that the project is exempt or is consistent with a GHG reduction plan.

Attachments (EXE, 876k)

A. Flow Chart of Staff's Recommended Interim GHG Significance Threshold Proposal
B. Development of Interim GHG Significance Thresholds
C. Resolution
D. GHG Significance Thresholds – Key Issues/Comments
E. Draft Guidance Document – Interim CEQA Greenhouse (GHG) Significance Threshold Document

---

Appendix C Air Quality Calculations

Table of Contents

Tables

This appendix describes the procedures used to analyze potential air quality impacts for the Lakeview Substation Project Proponent's Environmental Assessment (PEA).

1.0 ANALYSIS OVERVIEW

The following analyses of potential air quality impacts were conducted:

- Total peak daily emissions of criteria pollutants and precursors (volatile organic compounds [VOC], carbon monoxide [CO], nitrogen oxides [NOx], sulfur oxides [SOx], particulate matter smaller than 10 microns aerodynamic diameter [PM_{10}] and particulate matter smaller than 2.5 microns aerodynamic diameter [$PM_{2.5}$]) during construction (including construction of the Proposed Substation, distribution facilities, Subtransmission Source Lines, and telecommunication facilities, and demolition of the Nuevo and Model Pole Top substations) and operation of the Proposed Project were calculated and compared with California Environmental Quality Act (CEQA) significance thresholds for regional air quality impacts adopted by the South Coast Air Quality Management District (SCAQMD)

- On-site peak daily emissions of CO, NOx, PM_{10} and $PM_{2.5}$ during construction and operation of the proposed project were calculated and analyzed to evaluate potential localized impacts

- Total greenhouse gas (GHG) emissions during construction and operation of the Proposed Project were calculated to evaluate potential cumulative impacts from GHG emissions

Section 2 of this appendix describes the emission calculation procedures for the types of activities that are anticipated to generate emissions during construction and operation of the Proposed Project, Section 3 describes the calculation of peak daily emissions, Section 4 describes the calculation of total GHG emissions, and Section 5 describes the analysis of potential localized impacts. References are provided in Section 6. The associated calculations are provided in the attached tables.

2.0 EMISSION CALCULATIONS

2.1 Emission Sources

Construction and operational emissions can be distinguished as either on-site or off-site. On-site emissions principally consist of exhaust emissions (CO, VOC, NOx, SOx, PM_{10}, $PM_{2.5}$ and GHG) from construction equipment and motor vehicles, entrained PM_{10} and $PM_{2.5}$ from vehicles traveling on paved and unpaved surfaces, fugitive dust (PM_{10} and $PM_{2.5}$) from grading and excavation, VOC from asphaltic paving, and GHG from leakage of equipment containing sulfur hexafluoride (SF_6). Off-site emissions during the construction and operation phases consist of exhaust emissions and entrained paved and unpaved road dust from motor vehicles.

2.2 Construction Equipment Exhaust Emission Calculations

The combustion of fuel to provide power for the operation of construction equipment results in the generation of exhaust emissions. The following equation was used to calculate daily exhaust emissions from each type of construction equipment used during each construction phase for the Proposed Project:

$$E_{i,j} = EF_{i,j} \times H_j \times N_j \quad \text{(Eq. 1)}$$

where:

$E_{i,j}$ = Emissions of pollutant i from equipment type j [pounds/day]

$EF_{i,j}$ = Emission factor for pollutant i from equipment type j [pounds/operating hour]

H_j = Daily operating time for equipment type j [hours/day]

N_j = Number of pieces of equipment of type j

The exhaust emission factors, $EF_{i,j}$, used for the calculations for diesel-fueled equipment are composite horsepower-based off-road emission factors for 2012, the year construction is anticipated to begin, developed for the SCAQMD by the California Air Resources Board (CARB) from its OFFROAD 2007 Model (SCAQMD, 2008a). The composite off-road emission factors were derived based on equipment type (e.g., tractor, dozer, scraper), and average equipment age and horsepower rating within horsepower ranges for the year.

The emission factors developed by CARB for the SCAQMD are listed in Table 48 in the attached tables. They include emission factors for VOC, CO, NOx, SOx and PM_{10}, as well as two GHGs (carbon dioxide [CO_2] and methane [CH_4]). $PM_{2.5}$ emission factors were calculated by multiplying the PM_{10} emission factors by the $PM_{2.5}$ fraction of PM_{10} in construction equipment engine exhaust (SCAQMD, 2006).

Aerial lifts and some of the forklifts to be used during construction of the Proposed Project are anticipated to be propane-fueled. Since the emission factors available from the SCAQMD are only for diesel-fueled equipment, AECOM used the CARB OFFROAD 2007 Model to calculate total daily emissions and total daily operating hours for natural gas-fueled[1] aerial lifts and forklifts during 2012 in the SCAQMD's jurisdiction. Total daily emissions by equipment horsepower range were then divided by total daily operating hours to calculate hourly emission factors. The resulting emission factors are listed in Table 48 in the attached tables.

The following equation was used to calculate total GHG emissions from each type of construction equipment during each construction phase:

---

[1] The OFFROAD 2007 Model does not calculate emissions from propane-fueled equipment. Therefore, emissions from natural gas-fueled equipment were used to estimate emissions from propane-fueled equipment.

$$E_{GHG,j} = (E_{CO2,j} + 21 \times E_{CH4,j}) \times D_j \times 4.536 \times 10^{-4} \quad \text{(Eq. 2)}$$

where:

$E_{GHG,j}$ = Total GHG emissions from equipment type j [metric tons (1,000 kilograms) carbon dioxide equivalent]

$E_{CO2,j}$ = Daily CO_2 emissions from equipment type j [pounds/day]

21 = Global warming potential for CH_4 relative to CO_2

$E_{CH4,j}$ = Daily CH_4 emissions from equipment type j [pounds/day]

D_j = Days equipment of type j are used during the construction phase

4.536×10^{-4} = Metric tons per pound unit conversion

Table 3.5, Construction Equipment and Workforce Estimates, in Chapter 3, Project Description, of the PEA provided the types, number, daily operating hours and total operating days for construction equipment anticipated to be used during each construction phase for the Proposed Project. Horsepower ratings for the equipment were estimated from typical horsepower ratings for the types of equipment anticipated to be used. All construction equipment exhaust emissions were anticipated to occur on-site.

Daily VOC, CO, NOx, SOx, PM_{10} and $PM_{2.5}$ and total GHG construction equipment exhaust emissions calculations for each construction phase are provided in Tables 7 through 46 in the attached tables.

2.3 Motor Vehicle Exhaust Emission Calculations

The combustion of fuel in motor vehicle engines results in the generation of exhaust emissions. The following equation was used to calculate daily exhaust emissions from each type of motor vehicle used during each construction phase and during operation of the Proposed Project:

$$E_{i,j} = EF_{i,j} \times VMT_j \times N_j \quad \text{(Eq. 3)}$$

where:

$E_{i,j}$ = Emissions of pollutant i from motor vehicle type j [pounds/day]

$EF_{i,j}$ = Emission factor for pollutant i from motor vehicle type j [pounds/vehicle-mile-traveled]

VMT_j = Daily vehicle-miles-traveled (VMT) by motor vehicle type j [miles/day]

N_j = Number of motor vehicles of type j

The SCAQMD (2007a) has derived motor vehicle emission factors using CARB's EMFAC 2007 (v2.3) BURDEN model. The emission factors were derived by dividing the total daily district-wide emissions by total daily vehicle-miles-traveled (VMT) to obtain emission factors in pounds per mile traveled. Emission factors were derived for gasoline-fueled passenger/light-duty vehicles and diesel-fueled medium-/heavy-duty vehicles by taking the weighted average of vehicle types and simplifying them into two categories - passenger/light-duty and medium-/heavy-duty vehicles (e.g., delivery trucks). Emission factors were also derived for heavy heavy-duty diesel-fueled trucks, which have a vehicle weight ranging between 33,001 and 60,000 pounds.

The emission factors developed by the SCAQMD (2007a) are listed in Tables 49 and 50 in the attached tables. They include emission factors for VOC, CO, NOx, SOx, PM_{10}, CO_2 and CH_4. $PM_{2.5}$ emission factors were calculated by multiplying the PM_{10} emission factors by the $PM_{2.5}$ fraction of PM_{10} in motor vehicle exhaust (SCAQMD, 2006).

The following equation was used to calculate total GHG emissions from each type of vehicle during each construction phase and during operation of the Proposed Project:

$$E_{GHG,j} = (E_{CO2,j} + 21 \times E_{CH4,j}) \times D_j \times 4.536 \times 10^{-4} \qquad \text{(Eq. 2)}$$

where:

$E_{GHG,j}$ = Total GHG emissions from vehicle type j [metric tons carbon dioxide equivalent]

$E_{CO2,j}$ = Daily CO_2 emissions from vehicle type j [pounds/day]

21 = Global warming potential for CH_4 relative to CO_2

$E_{CH4,j}$ = Daily CH_4 emissions from vehicle type j [pounds/day]

D_j = Days vehicles of type j are used during the construction phase

4.536×10^{-4} = Metric tons per pound unit conversion

The types of vehicles, the vehicle categories used to assign emission factors, the number of vehicles used and the basis for estimating the number of vehicles during each construction phase and during operation of the Proposed Project are listed in Table C-1, Motor Vehicle Categories and Numbers. The daily on-site and off-site VMT for each type of vehicle and the basis for the VMT estimates during each construction phase and during operation of the Proposed Project are listed in Table C-2, Motor Vehicle Daily Vehicle-Miles-Traveled. Table C-2 also lists estimated VMT for travel on paved and unpaved roads and surfaces. Although exhaust emissions are independent of the type of surface, entrained fugitive particulate matter emission factors, as discussed in Section 2.4, Motor Vehicle Entrained Particulate Matter Calculations, are different for travel on paved and unpaved surfaces.

Daily motor vehicle exhaust emission calculations are provided in Tables 7 through 47 in the attached tables.

Table C-1 Motor Vehicle Categories and Numbers

Vehicle	Category[1]	Number	Basis for Number[2]
Substation Survey			
Survey Truck	Passenger	2	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Substation Grading			
Water Truck	HHDT	1	Table 3.5
Tool Truck	Passenger	1	Table 3.5
Pickup 4x4	Passenger	1	Table 3.5
Dump Truck	HHDT	45	Based on 40,000 CY export/import (Table 3.1) over 90 days and 10 CY/truck: 40,000 / 90 / 10 = 44.4
Worker Commute	Passenger	15	Table 3.5
Substation Fencing			
Flatbed Truck	Delivery	1	Table 3.5
Crewcab Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	4	Table 3.5
Substation Civil			
Dump Truck	HHDT	1	Based on 450 CY excavated (Table 3.1) over 60 days and 10 CY/truck: 450 / 60 / 10 = 0.8
Water Truck	HHDT	1	Table 3.5
Tool Truck	Passenger	1	Table 3.5
Concrete Truck	HHDT	9	Based on total of 445 CY concrete poured (Table 3.1) over 5 days and 10 CY/truck: 445 / 5 / 10 = 8.9
Worker Commute	Passenger	10	Table 3.5
Substation MEER			
Carry-all Truck	Delivery	1	Table 3.5
Stake Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	4	Table 3.5
Substation Electrical			
Crew Truck	Passenger	2	Table 3.5
Worker Commute	Passenger	10	Table 3.5
Substation Wiring			
Worker Commute	Passenger	5	Table 3.5
Substation Transformers			

Vehicle	Category[1]	Number	Basis for Number[2]
Crew Truck	Passenger	1	Table 3.5
Low Bed Truck	HHDT	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Substation Maintenance Crew Equipment Check			
Maintenance Truck	Passenger	2	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Substation Testing			
Crew Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Substation Asphalting			
Stake Truck	HHDT	1	Table 3.5
Dump Truck	HHDT	1	Table 3.5
Crew Truck	Passenger	2	Table 3.5
Asphalt Delivery Truck	HHDT	4	Based on 308 CY (Table 3.1) over 8 days and 10 CY/truck: 308 / 8 / 10 = 3.9
Aggregate Base Delivery Truck	HHDT	6	Based on 370 CY (Table 3.1) over 7 days and 10 CY/truck: 370 / 7 / 10 = 5.3
Worker Commute	Passenger	6	Table 3.5
Substation Landscaping			
Dump Truck	HHDT	1	Table 3.5
Crushed Rock Delivery Truck	HHDT	7	Based on 1,050 CY (Table 3.1) over 15 days and 10 CY/truck: 1,050 /15 / 10 = 7.0
Worker Commute	Passenger	6	Table 3.5
Substation Irrigation			
Crew Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	7	Table 3.5
Distribution Civil			
Dump Truck	HHDT	4	Based on 315 CY (Table 3.1) over 9 days and 10 CY/truck: 450 / 9 / 10 = 3.5
Delivery Truck	HHDT	1	Table 3.5
Concrete Truck	Delivery	2	Based on 100 CY (estimate) over 9 days and 10 CY/truck: 100 / 9 / 10 = 1.1
Worker Commute	Passenger	5	Table 3.5
Distribution Electrical			
Rodder Truck	HHDT	1	Table 3.5
Reel Truck	HHDT	1	Table 3.5

Vehicle	Category[1]	Number	Basis for Number[2]
Line Truck	Delivery	1	Table 3.5
Troubleman Truck	Delivery	1	Table 3.5
Boom Truck	HHDT	1	Table 3.5
Foreman Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	8	Table 3.5
Subtransmission Survey			
1/2-Ton Pick-up Truck, 4x4	Passenger	1	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Subtransmission Marshalling Yard			
1-Ton Crew Cab, 4x4	Delivery	1	Table 3.5
Truck, Semi Tractor	HHDT	1	Table 3.5
Worker Commute	Passenger	4	Table 3.5
Subtransmission Right-of-Way Clearing			
Water Truck	HHDT	4	Based on 16,000 gal/day and 4,000 gal truck: 16,000 / 4,000 = 4
1-Ton Crew Cab, 4x4	Delivery	1	Table 3.5
Lowboy Truck/Trailer	HHDT	1	Table 3.5
Worker Commute	Passenger5	5	Table 3.5
Subtransmission Roads and Landing Work			
Water Truck	HHDT	8	Based on 32,000 gal/day and 4,000 gal/truck: 32,000 / 4,000 = 8
1-Ton Crew Cab, 4x4	Delivery	1	Table 3.5
Lowboy Truck/Trailer	HHDT	1	Table 3.5
Aggregate Base Delivery Truck	HHDT	29	Based on 4,000 CY (Section 3.2.3.2) over 14 days and 10 CY/truck: 4,000 / 14 / 10 = 28.6
Worker Commute	Passenger	5	Table 3.5
Subtransmission Guard Structure Installation			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
Extendable Flat Bed Pole Truck	HHDT	1	Table 3.5
Auger Truck	HHDT	1	Table 3.5
30-Ton Crane Truck	HHDT	1	Table 3.5
80ft. Hydraulic Manlift/Bucket Truck	HHDT	1	Table 3.5

Vehicle	Category[1]	Number	Basis for Number[2]
Worker Commute	Passenger	6	Table 3.5
Subtransmission Wood Poles Removal			
1-Ton Crew Cab, 4x4	Delivery	1	Table 3.5
Flat Bed Truck/Trailer	HHDT	1	Table 3.5
30-Ton Crane Truck	HHDT	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Subtransmission TSP Foundations Installation			
Water Truck	HHDT	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
10-CY Dump Truck	HHDT	8	Based on excavating 18' dia. x 40' deep (Table 3.2) = 74.5 CY foundation/day and 10 CY truck: 74.5 / 10 = 7.5
10-CY Concrete Mixer Truck	HHDT	8	Based on pouring 18' dia. x 40' deep (Table 3.2) = 74.5 CY foundation/day and 10 CY truck: 74.5 / 10 = 7.5
30-Ton Crane Truck	HHDT	1	Table 3.5
Auger Truck	HHDT	1	Table 3.5
Worker Commute	Passenger	7	Table 3.5
Subtransmission Wood Pole Installation			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
Worker Commute	Passenger	8	Table 3.5
Subtransmission Steel Pole Haul			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
40' Flat Bed Truck/Trailer	HHDT	1	Table 3.5
Worker Commute	Passenger	4	Table 3.5
Subtransmission Steel Pole Assembly			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
Worker Commute	Passenger	8	Table 3.5
Subtransmission Steel Pole Erection			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5

Vehicle	Category[1]	Number	Basis for Number[2]
Worker Commute	Passenger	8	Table 3.5
Subtransmission Conductor Installation			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
Wire Truck/Trailer	HHDT	1	Table 3.5
Dump Truck (Trash)	HHDT	1	Table 3.5
Bucket Truck	HHDT	1	Table 3.5
22-Ton Manitex	HHDT	1	Table 3.5
Splicing Rig	Delivery	1	Table 3.5
Splicing Lab	Delivery	1	Table 3.5
3 Drum Straw Line Puller	HHDT	1	Table 3.5
Static Truck/Tensioner	HHDT	1	Table 3.5
Worker Commute	Passenger	16	Table 3.5
Subtransmission Guard Structure Removal			
3/4-Ton Pick-up Truck, 4x4	Delivery	1	Table 3.5
1-Ton Crew Cab Flat Bed, 4x4	Delivery	1	Table 3.5
Extendable Flat Bed Pole Truck	HHDT	1	Table 3.5
30-Ton Crane Truck	HHDT	1	Table 3.5
80-Foot Hydraulic Manlift/Bucket Truck	HHDT	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Subtransmission Restoration			
Water Truck	HHDT	1	Table 3.5
1-Ton Crew Cab, 4x4	Delivery	1	Table 3.5
Lowboy Truck/Trailer	HHDT	1	Table 3.5
Worker Commute	Passenger	7	Table 3.5
Telecommunications Control Building			
Van	Passenger	2	Table 3.5
Crew Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	4	Table 3.5
Telecommunications Overhead Installation			
Bucket Truck	Delivery	2	Table 3.5
Splice Lab Truck	Delivery	1	Table 3.5

Vehicle	Category[1]	Number	Basis for Number[2]
Crew Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Telecommunications Underground Facility			
Crew Truck	Delivery	2	Table 3.5
Flatbed Truck	HHDT	1	Table 3.5
Stake Truck	HHDT	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Telecommunications Underground Installation			
Reel Truck	HHDT	2	Table 3.5
Crew Truck	Delivery	1	Table 3.5
Splice Lab Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Telecommunications Systems at Other Locations			
Van	Passenger	6	Table 3.5
Worker Commute	Passenger	6	Table 3.5
Nuevo Substation Demolition Civil			
Dump Truck	HHDT	2	Table 3.5
Water Truck	HHDT	1	Table 3.5
Tool Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	5	Table 3.5
Nuevo Substation Demolition Electrical			
Tool Trailer	Passenger	1	Table 3.5
Crew Truck	Passenger	2	Table 3.5
Worker Commute	Passenger	5	Table 3.5
Nuevo Substation Demolition Equipment Check			
Maintenance Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Nuevo Substation Demolition Testing			
Crew Truck	Passenger	1	Table 3.5
Worker Commute	Passenger	2	Table 3.5
Model P. T. Substation Demolition Civil			
Dump Truck	HHDT	1	Table 3.5
Flatbed Truck	HHDT	1	Table 3.5
Foreman Truck	Passenger	1	Table 3.5

Vehicle	Category[1]	Number	Basis for Number[2]
Worker Commute	Passenger	5	Table 3.5
Model P. T. Substation Demolition Electrical			
Line Truck	Delivery	1	Table 3.5
Troubleman Truck	Delivery	1	Table 3.5
Boom Truck	Delivery	1	Table 3.5
Foreman Truck	Delivery	1	Table 3.5
Flatbed Truck	Delivery	1	Table 3.5
Pumper/Tanker Truck	Delivery	1	Table 3.5
Worker Commute	Passenger	5	Table 3.5
Operations			
Subtransmission Line Inspection	Passenger	1	Section 3.12
Substation Site Visit	Passenger	1	Section 3.12

Notes:
CY = cubic yards; dia = diameter; gal = gallons; MEER = Mechanical and Electrical Equipment Room; TSP = Tubular Steel Poles; ' = feet

[1] Category is used to assign emission factors. 'Passenger' is passenger vehicles in Table 49 in the attached tables, and is used for all gasoline-fueled vehicles. 'Delivery' is delivery vehicles in Table 49 in the attached tables, and is used for diesel-fueled vehicles except for heavy, heavy duty diesel-fueled trucks (HHDT). 'HHDT' is heavy, heavy-duty diesel-fueled trucks in Table 50 in attached tables.

[2] Table and section numbers refer to tables and sections in PEA Chapter 3, Project Description.

Table C-2 Motor Vehicle Daily Vehicle-Miles-Traveled

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Substation Survey					
Survey Truck	1	60	0	60	Survey company assumed to be within 30 mi. of substation
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Grading					
Water Truck	2	10	0	10	Water supply within 5 mi.
Tool Truck	1	14	0	14	Travel from Menifee Service Center
Pickup 4x4	1	14	0	14	Travel from Menifee Service Center
Dump Truck	0.2	60	0	60	Borrow/disposal sites within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Substation Fencing					
Flatbed Truck	2	14	0	14	Travel from Menifee Service Center
Crewcab Truck	1	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Civil					
Dump Truck	1	0	0	0	Dump truck stays on-site
Water Truck	1	10	0	10	Water supply assumed to be within 5 mi. of substation
Tool Truck	1	14	0	14	Travel from Menifee Service Center
Concrete Truck	0.1	60	0	60	Concrete supplier within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation MEER					
Carry-all Truck	1	14	0	14	Travel from Menifee Service Center
Stake Truck	1	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Electrical					
Crew Truck	1	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Wiring					
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Transformers					
Crew Truck	1	14	0	14	Travel from Menifee Service Center
Low Bed Truck	1	0	0	0	Low bed truck stays on-site
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Maintenance Crew Equipment Check					
Maintenance Truck	0.5	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Testing					
Crew Truck	0.5	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Asphalting					

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Stake Truck	1	0	0	0	Stake truck stays on-site
Dump Truck	1	0	0	0	Dump truck stays on-site
Crew Truck	2	14	0	14	Travel from Menifee Service Center
Asphalt Delivery Truck	0.1	60	0	60	Asphalt supplier within 30 mi.
Aggregate Base Delivery Truck	0.1	60	0	60	Aggregate supply within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Landscaping					
Dump Truck	1	0	0	0	Dump truck stays on-site
Crushed Rock Delivery Truck	0.1	60	0	60	Crushed rock supply within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Substation Irrigation					
Crew Truck	0.5	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Distribution Civil					
Dump Truck	0	60	0	60	Disposal site within 30 mi.
Delivery Truck	0	60	0	60	Equipment supplier within 30 mi.
Concrete Truck	0	60	0	60	Concrete supplier within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Distribution Electrical					
Rodder Truck	0	14	0	14	Travel from Menifee Service Center
Reel Truck	0	14	0	14	Travel from Menifee Service Center
Line Truck	0	14	0	14	Travel from Menifee Service Center
Troubleman Truck	0	14	0	14	Travel from Menifee Service Center
Boom Truck	0	14	0	14	Travel from Menifee Service Center
Foreman Truck	0	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Survey					
1/2-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Worker Commute	0	60	0	0	Workers assumed to be located within 30 mi.
Subtransmission Marshalling Yard					
1-Ton Crew Cab, 4x4	5	0	0	0	Traveling on-site 25% of 2 hr/day at 10 mph
Truck, Semi Tractor	2.5	0	0	0	Traveling on-site 25% of 1 hr/day at 10 mph
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Right-of-Way Clearing					
Water Truck	1	10	3	13	Water supply within 5 mi. of Subtransmission Source Line Route (paved); roundtrip along 1.5 mi. of Subtransmission Source Line Route (unpaved)
1-Ton Crew Cab, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Lowboy Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Roads and Landing Work					
Water Truck	1	10	3	13	Water supply within 5 mi. of Ssubtransmission Source Line Route (paved); roundtrip along 1.5 mi. of Subtransmission Source Line Route (unpaved)
1-Ton Crew Cab, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Lowboy Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Aggregate Base Delivery Truck	0	60	4	64	Aggregate supply within 30 mi. of Subtransmission Source Line Route (paved); roundtrip along Subtransmission Source Line Route (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Guard Structure Installation					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Extendable Flat Bed Pole Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Auger Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
30-Ton Crane Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
80-Foot Hydraulic Manlift/Bucket Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Wood Poles Removal					
1-Ton Crew Cab, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Flat Bed Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
30-Ton Crane Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission TSP Foundations Installation					
Water Truck	0	10	4	14	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
10-cu. yd. Dump Truck	0	60	4	64	Disposal site within 30 mi. of Subtransmission Source Line Route (paved); roundtrip along Subtransmission Source Line Route (unpaved)
10-cu. yd. Concrete Mixer Truck	0	60	4	64	Concrete supply within 30 mi. of Subtransmission Source Line Route (paved); roundtrip along Subtransmission Source Line Route (unpaved)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
30-Ton Crane Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Auger Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Wood Pole Installation					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Steel Pole Haul					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
40' Flat Bed Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Steel Pole Assembly					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Steel Pole Erection					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Conductor Installation					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Wire Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Dump Truck (Trash)	0	60	4	64	Disposal site within 30 mi. of Subtransmission Source Line Route (paved); roundtrip along Subtransmission Source Line Route (unpaved)
Bucket Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
22-Ton Manitex	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Splicing Rig	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Splicing Lab	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
3 Drum Straw Line Puller	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Static Truck/Tensioner	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Guard Structure Removal					
3/4-Ton Pick-up Truck, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab Flat Bed, 4x4	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Extendable Flat Bed Pole Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
30-Ton Crane Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
80-Foot Hydraulic Manlift/Bucket Truck	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Subtransmission Restoration					
Water Truck	3	10	3	13	Travel from Menifee Service Center (paved); 1.5 mi. roundtrip along Subtransmission Source Line ROW (unpaved)
1-Ton Crew Cab, 4x4	3	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Lowboy Truck/Trailer	0	14	4	18	Travel from Menifee Service Center (paved); roundtrip along Subtransmission Source Line ROW (unpaved)
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Telecommunications Control Building					
Van	0	14	0	14	Travel from Menifee Service Center
Crew Truck	0	14	0	14	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Telecommunications Overhead Installation					
Bucket Truck	0	0	21	21	Roundtrip along Subtransmission Source Line ROW (4 mi.) plus travel along ROW from new Subtransmission Source Line ROW to Moval Substation (17 mi.)
Splice Lab Truck	0	0	21	21	Roundtrip along Subtransmission Source Line ROW (4 mi.) plus travel along ROW from new Subtransmission Source Line ROW to Moval Substation (17 mi.)
Crew Truck	0	0	21	21	Roundtrip along Subtransmission Source Line ROW (4 mi.) plus travel along ROW from new Subtransmission Source Line ROW to Moval Substation (17 mi.)

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Telecommunications Underground Facility					
Crew Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Flatbed Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Stake Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Telecommunications Underground Installation					
Reel Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Crew Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Splice Lab Truck	0	1	0	1	Worksite within 0.5 mi. from nearest substation
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Telecommunications Systems at Other Locations					
Van	0	60	0	60	Other substations assumed within 30 mi.
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Nuevo Substation Demolition Civil					
Dump Truck	1	60	0	60	Disposal site within 30 mi.
Water Truck	1	10	0	10	Water supply within 5 mi.
Tool Truck	1	0	0	0	Tool truck stays on-site
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Nuevo Substation Demolition Electrical					
Tool Trailer	1	0	0	0	Tool trailer stays on-site
Crew Truck	1	12	0	12	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Nuevo Substation Demolition Equipment Check					
Maintenance Truck	0.5	12	0	12	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Nuevo Substation Demolition Testing					
Crew Truck	0.5	12	0	12	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Model P. T. Substation Demolition Civil					
Dump Truck	1	60	0	60	Disposal site within 30 mi.

Vehicle	On-Site Daily VMT (mi)[1]	Off-Site Daily VMT (mi)			Notes
		P[2]	U[2]	T[2]	
Flatbed Truck	1	12	0	12	Travel from Menifee Service Center
Foreman Truck	1	12	0	12	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Model P. T. Substation Demolition Electrical					
Line Truck	0.5	12	0	12	Travel from Menifee Service Center
Troubleman Truck	0.5	12	0	12	Travel from Menifee Service Center
Boom Truck	0.5	12	0	12	Travel from Menifee Service Center
Foreman Truck	0.5	12	0	12	Travel from Menifee Service Center
Flatbed Truck	0.5	12	0	12	Travel from Menifee Service Center
Pumper/Tanker Truck	0.5	12	0	12	Travel from Menifee Service Center
Worker Commute	0	60	0	60	Workers assumed to be located within 30 mi.
Operations					
Subtransmission Line Inspection	0	60	7	67	Trip origin within 30 mi.; roundtrip along entire Subtransmission Source Line Route (unpaved)
Substation Site Visit	0	60	0	60	Trip origin within 30 mi.

Notes:
CY = cubic yards; hr/day = hours per day; MEER = Mechanical and Electrical Equipment Room; mi = miles; mph = miles per hour; ROW = rights-of-way; TSP = Tubular Steel Poles; ‘ = feet
[1] On-site travel estimated from site dimensions. All on-site travel is unpaved, except for marshalling yard and Nuevo and Model Pole Top substations.
[2] P = off-site paved road/surface VMT; U = off-site unpaved road/surface VMT; T = total off-site VMT

2.4 Motor Vehicle Entrained Particulate Matter Emission Calculations

Motor vehicles entrain particulate matter from the surfaces on which they travel. The following equation was used to calculate daily entrained particulate matter emissions from each type of motor vehicle used during each construction phase and during operation for the Proposed Project:

$$E_{i,j,k} = EF_{i,j,k} \times VMT_{j,k} \times N_j \quad \text{(Eq. 4)}$$

where:

$E_{i,j,k}$ = Emissions of pollutant i (PM_{10} or $PM_{2.5}$) from motor vehicle type j traveling on surface type k (paved or unpaved) [pounds/day]

$EF_{i,j,k}$ = Emission factor for pollutant i from motor vehicle type j on surface type k [pounds/VMT]

$VMT_{j,k}$ = Daily VMT by motor vehicle type j on surface type k [miles/day]

N_j = Number of motor vehicles of type j

The following equation (EPA, 2006a) was used to calculate the emission factors for motor vehicles traveling on paved roads and surfaces:

$$EFi_{i,j,P} = k_{i,p} \times (sL / 2)^{0.65} \times (W_j/3)^{1.5} - C \qquad \text{(Eq. 5)}$$

where:

$EF_{i,j,P}$ = Emission factor for pollutant i (PM_{10} or $PM_{2.5}$) from motor vehicle type j traveling on paved surfaces [pounds/VMT]

$k_{i,P}$ = Particle size multiplier for pollutant i

= 0.016 for PM_{10}

= 0.0024 for $PM_{2.5}$

sL = Surface silt loading [grams/square meter]

W_j = Average weight of vehicles traveling on the paved surface [tons]

C = Exhaust, brake wear and tire wear adjustment [pounds/VMT]

= 0.0047 for PM_{10}

= 0.00036 for $PM_{2.5}$

The paved road silt loading of 0.035 grams/square meter and the average on-road vehicle weight of 3.2 tons in Riverside County from CARB (1997) were used for the calculations.

The following equation (EPA, 2006b) was used to calculate the emission factors for motor vehicles traveling on unpaved roads and surfaces:

$$EF_{i,i,U} = k_{i,u} \times (s / 12)^{0.9} \times (W_j/3)^{0.45} \times (1 - CE_U / 100) \qquad \text{(Eq. 6)}$$

where:

$EF_{i,j,U}$ = Emission factor for pollutant i (PM_{10} or $PM_{2.5}$) from motor vehicle type j traveling on unpaved surfaces [pounds/VMT]

$k_{i,u}$ = Particle size multiplier for pollutant i

= 1.5 for PM_{10}

= 0.15 for $PM_{2.5}$

s = Silt content of the unpaved surface [percent by weight]

W_j = Average weight of vehicles traveling on the unpaved surface [tons]

CE_U = Control efficiency for entrained particulate matter emissions from unpaved surfaces [percent]

The unpaved road silt content of 7.5 percent for overburden from the SCAQMD CEQA Handbook, (SCAQMD, 1993), Table A9-9-E-1, was used. Vehicle weights were estimated from the type of vehicle. The control efficiency of 57 percent from limiting speeds on unpaved roads to 15 miles per hour (mph) (SCAQMD, 2007b) was used for the calculations.

Entrained particulate matter emission factors by type of vehicle and surface are provided in Table 51 in the attached tables. Estimated daily VMT on paved and unpaved surfaces by type of vehicle during each construction phase and during operation of the Proposed Project are listed in Table C-2, Motor Vehicle Daily Vehicle-Miles-Traveled.

Motor vehicle entrained particulate matter emission calculations are provided in Tables 7 through 47 in the attached tables.

2.5 Earthwork Fugitive Particulate Matter Emission Calculations

Handling soil during excavation and grading generates fugitive particulate matter from soil dropping during transfers, wind erosion of temporary storage piles, and bulldozing, scraping and grading.

The following equation was used to calculate daily emissions from soil dropping during construction of the Proposed Project:

$$E_i = EF_i \times V_S \qquad \text{(Eq. 7)}$$

where:

E_i = Emissions of pollutant i (PM_{10} or $PM_{2.5}$) from soil dropping [pounds/day]

EF_i = Emission factor for pollutant i from soil dropping [pounds/cubic yard]

V_S = Volume of soil dropped [cubic yards/day]

The following equation (EPA, 2006c) was used to calculate the emission factor for fugitive particulate matter emissions from soil dropping:

$$EF_i = f_i \times 0.011 \times (WS / 5)^{1.3} / (M / 2)^{1.4} \times N_S \times D_S \qquad \text{(Eq. 8)}$$

where:

EF_i = Emission factor for fugitive particulate matter emissions from soil dropping

f_i = Mass fraction of pollutant i (PM_{10} or $PM_{2.5}$) in PM_{10} emissions from soil dropping

= 1 for PM_{10}

= 0.208 for $PM_{2.5}$ from SCAQMD (2006)

WS = Mean wind speed [miles/hour]

= 12 miles/hour from SCAQMD CEQA Air Quality Handbook (1993), Table 9-9-G

M = Soil moisture content [percent by weight]

= 10.6 percent average of near-surface soil samples from Proposed Substation Site preliminary geotechnical investigation

N_S = Number of times each cubic yard is dropped [number/day]

= 4 (assumption)

D_S = Soil density [tons/cubic yard]

= 1.47 tons/cubic yard average of near-surface soil samples from Proposed Substation Site preliminary geotechnical investigation

The following equation was used to calculate daily emissions from storage pile wind erosion during construction of the Proposed Project:

$$E_i = EF_i \times A_S \quad \text{(Eq. 9)}$$

where:

E_i = Emissions of pollutant i (PM_{10} or $PM_{2.5}$) from storage pile wind erosion [pounds/day]

EF_i = Emission factor for pollutant i from storage pile wind erosion [pounds/acre-day]

A_S = Exposed storage pile surface area [acres]

The following equation from the SCAQMD CEQA Air Quality Handbook (SCAQMD, 1993), Table 9-9-E, was used to calculate the emission factor for fugitive particulate matter emissions from storage pile wind erosion:

$$EF_i = f_i \times 0.85 \times (s / 1.5) \times (365 / 235) \times (P_W / 15) \times (1 - CE / 100) \quad \text{(Eq. 10)}$$

where:

EF_i = Emission factor for fugitive particulate matter emissions from storage pile wind erosion

f_i = Mass fraction of pollutant i (PM_{10} or $PM_{2.5}$) in PM_{10} emissions from storage pile wind erosion

= 1 for PM_{10}

= 0.208 for $PM_{2.5}$ from SCAQMD (2006)

s = Storage pile silt content [weight percent]

= 26.7 percent average of near-surface soil samples from Proposed Substation Site preliminary geotechnical investigation

P_W = Percent of time unobstructed wind speed exceeds 12 miles/hour

= 100 percent (conservative assumption)

CE = Control efficiency [percent]

= 90 percent from watering storage pile by hand at a rate of 1.4 gallons/hour-square yard (SCAQMD, 2007b)

The following equation was used to calculate daily emissions from bulldozing, scraping and grading during construction of the Proposed Project:

$$E_i = EF_i \times H_G \qquad \text{(Eq. 11)}$$

where:

E_i = Emissions of pollutant i (PM_{10} or $PM_{2.5}$) from bulldozing, scraping and grading [pounds/day]

EF_i = Emission factor for pollutant i from bulldozing, scraping and grading [pounds/hour]

H_G = Daily bulldozing, scraping and grading duration [hours/day]

The following equation (EPA, 1998) was used to calculate the emission factor for fugitive particulate matter emissions from bulldozing, scraping and grading:

$$EF_i = f_i \times 0.75 \times s^{1.5} / M^{1.4} \times (1 - CE / 100) \qquad \text{(Eq. 12)}$$

where:

EF_i = Emission factor for fugitive particulate matter emissions from bulldozing, scraping and grading

f_i = Mass fraction of pollutant i (PM_{10} or $PM_{2.5}$) in PM_{10} emissions from bulldozing, scraping and grading

= 1 for PM_{10}

= 0.208 for $PM_{2.5}$ from SCAQMD (2006) s = Material silt content [weight percent]

= 26.7 percent average of near-surface soil samples from Proposed Substation Site preliminary geotechnical investigation

M = Material moisture content [weight percent]

= 10.6 percent average of near-surface soil samples from Proposed Substation Site preliminary geotechnical investigation

CE = Control efficiency [percent]

= 61 percent from watering three times per day from SCAQMD (2007c)

The emission factor calculations are presented in Table 52 in the attached tables.

The daily hours of bulldozing, scraping and grading were calculated from the construction equipment usage estimates provided in Table 3.5, Construction Equipment and Workforce Estimaes, in Chapter 3, Project Description, of the PEA. Estimated daily volumes of soil handled and storage pile surface areas during construction phases that involve soil handling and temporary storage piles are listed in Table C-3, Estimated Soil Handling and Storage Pile Surface Areas by Construction Phase.

Earthwork fugitive particulate matter emission calculations are provided in Tables 7 through 47 in the attached tables.

Table C-3 Estimated Soil Handling and Storage Pile Surface Areas by Construction Phase

Construction Phase	Type	Daily Amount	Basis[1]
Substation Grading	Soil Dropping	450 CY	40,000 CY total (Table 3.1) over 90 days: 40,000 / 90 = 444
	Storage Piles	0.13 acres	450 CY total in two conical piles 7' tall x 58' diameter
Substation Civil	Soil Dropping	8 CY	450 CY total (Table 3.1) over 60 days: 450 / 60 = 7.5
Distribution Civil	Soil Dropping	50 CY	450 CY total (Table 3.1) over 9 days: 450 / 9 = 50
Subtransmission ROW Clearing	Soil Handling	200 CY	Clearing 10,800' long x 14' wide x 6" depth (Section 3.2.3.2) over 14 days: 10,800 x 14 x 0.5 / 27 / 14 = 200
Subtransmission Roads and Landings	Soil Handling	2,800	Cut and fill 8 acres (Table 3.4) x 18" depth (Section 3.2.3.2) over 14 days: 8 x 43,560 x 1.5 / 27 x 2 / 14 = 2,766
	Storage Piles	0.6 acres	8 acres (Table 3.4) over 14 days: 8 / 14 = 0.57
Subtransmission TSP	Soil	75 CY	Excavate 8' diameter x 40' deep (Table 3.2)

Construction Phase	Type	Daily Amount	Basis[1]
Foundations Installation	handling		per day = π x 8^2 / 4 x 40 / 27 = 74.5
Subtransmission Wood Pole Installation	Soil Handling	12 CY	Excavate 73 poles, 3' diameter x 11' deep (Table 3.2) over 19 days: 73 x π x 3^2 / 4 x 11 / 27 / 19 = 11.1
Telecommunications Underground Facility	Soil Handling	34 CY	Excavate duct banks, 3,950' long (Table 3.4) x 1.5' wide x 3' deep (Section 3.2.4) plus pull boxes and manholes, two 3' x 5' x 3' and three 4' x 4' x 5' (Section 3.2.4) over 20 days: (3,950 x 1.5 x 3 + 2 x 3 x 5 x 3 + 3 x 4 x 4 x 5) / 27 / 20 = 33.5
Model Pole Top Substation Decommissioning Civil	Soil Handling	130 CY	Excavate total of 260 CY over 2 days
	Storage Pile	0.04 acres	130 CY in one conical pile 7' tall x 22' diameter

Note:
CY = cubic yards; hr/day = hours per day; ROW = rights-of-way; TSP = Tubular Steel Poles; ' = feet; " = inches
[1] Table and section numbers refer to PEA Chapter 3, Project Description

2.6 Asphaltic Paving VOC Emission Calculations

Asphaltic paving generates VOC emissions as the asphalt cures. The following equation was used to calculate daily VOC emissions from asphaltic paving:

$$E = EF \times A_P \qquad \text{(Eq. 13)}$$

where:

E = VOC emissions from asphaltic paving [pounds/day]

EF = Emission factor for VOC from asphaltic paving [pounds/acre]

= 2.62 pounds/acre from URBEMIS 2007 User's Guide, Appendix A (URBEMIS, 2007)

A_P =Area paved [acres/day]

The maximum surface area paved in a single day would be 11,200 square feet (0.26 acres) for the Proposed Substation external driveway (see PEA Chapter 3, Project Description, Table 3.1, Substation Ground Improvements and Material Volumes). VOC emissions from asphaltic paving are calculated in Table 17 in the attached tables.

2.7 Equipment SF_6 Leakage GHG Emission Calculations

New circuit breakers installed at the Proposed Substation would be insulated with SF_6, which is a GHG. Leakage of SF_6 from the circuit breakers during operation of the Proposed Project would generate GHG emissions. The following equation was used to calculate GHG emissions from SF_6 leakage:

$$E = L / 100 \times M_{SF6} \times 23{,}200 \times 4.536 \times 10^{-4} \quad \text{(Eq. 14)}$$

where:

E = GHG emissions from SF_6 leakage [metric tons CO_2 equivalent/year]

L = SF_6 leakage rate [percent/year]

= 0.5 percent/year estimated by SCE

M_{SF6} = SF_6 in new circuit breakers [pounds]

= 378 pounds, estimated by SCE

23,200 = SF_6 global warming potential

4.536×10^{-4} = Metric tons/pound conversion factor

GHG emissions from SF_6 leakage are calculated in Table 47 in the attached tables.

3.0 PEAK DAILY EMISSIONS CALCULATIONS

Peak daily emissions of VOC, CO, NOx, SOx, PM_{10} and $PM_{2.5}$ during construction and operation of the Proposed Project were calculated for comparison with the SCAQMD's CEQA mass emissions CEQA significance thresholds.

2.1 Peak Daily Construction Emission Calculations

The following steps were used to estimate peak daily emissions during construction of the Proposed Project:

- Daily emissions during each of the construction phases in Table 3.5, Construction Equipment and Workforce Estimates, in Chapter 3, Project Description, of the PEA were calculated using the procedures in Section 2, Emission Calculations. The calculations are provided in Tables 7 through 46 in the attached tables, and total daily emissions for each construction phase are listed in Table 1 in the attached tables.

- The maximum daily emissions that may occur during construction of each component of the Proposed Project (Substation, distribution facilities, Subtransmission Source Lines and telecommunication facilities and during demolition of the Nuevo Substation and the Model Pole Top Substation) were estimated as follows:

- Daily emissions during the construction phases for each component of the Proposed Project that may overlap were added together to estimate daily emissions during overlapping construction phases. Construction phases that may overlap are listed in Table C-4, Possible Overlapping Construction Phases.

- The highest daily emissions among the overlapping and non-overlapping construction phases for each component of the Proposed Project were then determined.

- Construction of the Proposed Substation, distribution facilities, Subtransmission Source Lines and telecommunication facilities may all occur at the same time. Therefore, maximum daily emissions during simultaneous construction of these project components were estimated by adding together the maximum daily emissions during construction of the individual components estimated in the previous step.

- Demolition of the Nuevo and Model Pole Top substations may occur at the same time but would not commence until construction of the other Proposed Project components is completed. Therefore, the maximum daily emissions during the demolition activities for the two substations were added together to estimate maximum daily emissions during demolition.

- Peak daily construction emissions were the higher of the maximum daily emissions during construction of the new Proposed Project components and during demolition of the two existing substations.

The peak daily construction emissions calculations are provided in Table 2 in the attached tables.

Table C-4 Possible Overlapping Construction Phases

Project Component	Overlapping Construction Phases
Substation Construction	Grading
	Civil and Fencing
	MEER, Electrical, Wiring, Transformers, Equipment Check, Testing, Asphalting, Landscaping, Irrigation
Distribution Facilities Construction	All Phases
Subtransmission Source Line Construction	All Phases
Telecommunications Construction	Marshalling Yard, Right-of-Way Clearing, Roads and Landing Work
	Marshalling Yard, Tubular Steel Pole Foundations Installation, Steel Pole Haul, Steel Pole Assembly, Steel Pole Erection, Wood Pole Installation
	Marshalling Yard, Steel Pole Erection, Wood Pole Installation, Guard Structure Installation

Project Component	Overlapping Construction Phases
	Marshalling Yard, Existing Wood Poles Removal, Guard Structure Installation
	Marshalling Yard, Conductor Installation
	Marshalling Yard, Guard Structure Removal
	Marshalling Yard, Restoration
	Marshalling Yard, Right-of-Way Clearing, Roads and Landing Work
Nuevo Substation Demolition	Civil
	Electrical
	Maintenance Crew Equipment Check
	Testing
Model Pole Top Substation Demolition	Civil
	Electrical

2.2 Peak Daily Operational Emission Calculations

During operation of the Proposed Project, motor vehicle exhaust and entrained paved road particulate matter emissions would be generated by motor vehicle travel for inspections of the Proposed Substation and Subtransmission Source Lines. Emissions from these activities were calculated using the procedures described in Section 2.2, Construction Equipment Exhaust Emission Calculations, and Section 2.3, Motor Vehicle Exhaust Emission Calculations. The calculations of peak daily emissions considered visits to inspect both the Proposed Substation and the Subtransmission Source Lines on the same day, to ensure that emissions were not underestimated. The peak daily operational emission calculations are provided in Table 47 in the attached tables.

4.0 TOTAL GREENHOUSE GAS EMISSION CALCULATIONS

GHG emissions during each construction phase and during operation of the Proposed Project were calculated using the procedures described in Section 2.2, Construction Equipment Exhaust Emission Calculations, Section 2.3, Motor Vehicle Exhaust Emission Calculations, and Section 2.7, Equipment SF_6 Leakage GHG Emission Calculations. The calculations are provided in Tables 7 through 47 in the attached tables. Total GHG emissions during construction and during each construction phase are listed in Table 6 in the attached Tables, and GHG emissions during project operation are in Table 47.

5.0 LOCALIZED IMPACTS ANALYSIS

The SCAQMD (2008b) has developed look-up tables that can be used to evaluate the potential for construction emissions to cause localized exceedances of the ambient air quality CEQA significance thresholds. This localized significance thresholds (LST) analysis consists of comparing maximum daily on-site CO, NOx, PM_{10}, and $PM_{2.5}$

emissions at individual locations with maximum allowable emissions obtained from the look-up tables. The maximum allowable emissions in the tables depend on the location within the South Coast Air Basin, the size (disturbed area) of the construction activities, and the distance from the construction site boundary to the nearest receptor. Receptors for the analysis include residences for PM_{10} and $PM_{2.5}$ and either residences or commercial locations for CO and NOx.

Daily on-site emissions during each construction phase were calculated using the procedures described in Section 2, Emission Calculations, for use in the LST analysis for impacts during construction of the Proposed Project. All construction equipment usage and fugitive particulate matter emissions from earthwork were assumed to occur on-site. On-site motor vehicle travel estimates to calculate on-site vehicle exhaust and entrained particulate matter emissions are listed in Table C-2, Motor Vehicle Daily Vehicle-Miles-Traveled. Daily on-site construction emissions calculations are provided in Tables 7 through 46 in the attached tables, and total daily on-site emissions are listed by construction phase in Table 3 in the attached tables.

Maximum daily on-site emissions that could occur at a single location during construction of each of the components of the Proposed Project were used in the LST analysis. On-site emissions during construction of the Proposed Substation, distribution facilities and telecommunication facilities and during demolition of the Nuevo and Model Pole Top substations were assumed to occur at a single location each day. On-site emissions during construction of the Proposed Subtransmission Source Line Route were divided by the number of separate locations at which construction activities for that phase of construction would occur during one day to calculate the emissions used in the analyses. The following information was used for this analysis:

- Guard Structure Installation: 4 structures per day (4 locations)
- Existing Wood Poles Removal: 10 poles per day (10 locations)
- Tubular Steel Pole Foundations Installation: 1 foundation per day (1 location)
- Wood Pole Installation: 4 poles per day (1 location)
- Steel Pole Haul: 4 locations per day (4 locations)
- Steel Pole Assembly: 3 poles per day (3 locations)
- Steel Pole Erection: 3 poles per day (3 locations)
- Conductor Installation: 1 pull, 1 tension and 1 splicing site per day (3 locations)
- Guard Structure Removal: 4 structures per day (4 locations)

Emissions generated during Proposed Subtransmission Source Line Route rights-of-way (ROW) clearing, roads and landing work, and restoration were not included in the analyses, since these emissions would occur over distances of approximately one mile each day, rather than at fixed locations. Daily on-site emissions at a single location for each construction phase and maximum daily on-site emissions during construction of each Proposed Project component are listed in Table 4 in the attached tables.

The SCAQMD look-up tables for the LST analysis list maximum daily allowable on-site emissions that will not cause LSTs to be exceeded for 1-, 2- and 5-acre construction sites and for receptor distances from the boundary of 25, 50, 100, 200 and 500 meters. The values for a 5-acre site were used for the analyses for the Proposed Substation construction, and the values for a 1-acre site were used for construction of the other Proposed Project components. Linear interpolation of the emissions in the look-up tables was used to calculate the maximum allowable emissions corresponding to the actual receptor distances. The analyses are shown in Table 5 in the attached tables.

Emissions during operation of the Proposed Project would be solely from motor vehicle travel to visit the Proposed Substation Site and to inspect the Proposed Subtransmission Source Lines. Since these emissions would not occur at a single location each day, they would not cause the localized significance thresholds to be exceeded.

6.0 REFERENCES

California Air Resources Board (CARB). 1997. Emission Inventory Methodology 7.9, Entrained Paved Road Dust. [online] http://www.arb.ca.gov/ei/areasrc/fullpdf/full7-9.pdf [cited March 2010].

US Environmental Protection Agency (EPA). 1998. Compilation of Air Pollutant Emission Factors (AP-42), Section 11.9, Western Surface Coal Mining. [online] http://www.epa.gov/ttn/chief/ap42/ch11/final/c11s09.pdf [cited March 2010].

EPA. 2006a. Compilation of Air Pollutant Emission Factors (AP-42), Section 13.2.1, Paved Roads. [online] http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0201_2006.pdf [cited March 2010].

EPA. 2006b. Compilation of Air Pollutant Emission Factors (AP-42), Section 13.2.2, Unpaved Roads. [online] http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0202.pdf [cited March 2010].

EPA. 2006c. Compilation of Air Pollutant Emission Factors (AP-42), Section 13.2.4, Aggregate Handling and Storage Piles. [online] http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0204.pdf [cited March 2010].

South Coast Air Quality Management District (SCAQMD). 1993.CEQA Air Quality Handbook. November.

SCAQMD. 2006. Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds. [online] http://www.aqmd.gov/ceqa/handbook/PM2_5/finalAppA.doc [cited March 2010].

SCAQMD. 2007a. EMFAC 2007 (v2.3) Emission Factors (On-Road). [online] http://www.aqmd.gov/ceqa/handbook/onroad/onroadEF07_26.xls and http://www.aqmd.gov/ceqa/handbook/onroad/onroadEFHHDT07_26.xls [cited March 2010].

SCAQMD. 2007b. Table XI-B, Mitigation Measure Examples, Fugitive Dust from Materials Handling. [online]

http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/TableXI-A.doc [cited March 2010].

SCAQMD. 2007c. Table XI-A, Mitigation Measure Examples, Fugitive Dust from Construction & Demolition. [online] http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/TableXI-A.doc [cited March 2010].

SCAQMD. 2008a. Off-road Mobile Source Emission Factors (Scenario Years 2007 - 2025). [online] http://www.aqmd.gov/ceqa/handbook/offroad/offroadEF07_25.xls [cited March 2010].

SCAQMD. 2008b. Final Localized Significance Threshold Methodology. [online] http://www.aqmd.gov/ceqa/handbook/LST/Method_final.pdf [cited March 2010].

URBEMIS. 2007. URBEMIS 9.2 Users Manual, Appendix A. [online] http://www.urbemis.com/software/URBEMIS9%20Users%20Manual%20Appendices.pdf [cited March 2010].

This page intentionally left blanK

Table 1
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions by Construction Phase

Phase	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	1.08	0.10
Grading	11.63	52.09	117.60	0.16	33.18	9.46
Fencing	0.65	4.53	3.55	0.01	2.86	0.48
Civil	3.78	26.62	32.41	0.05	5.50	2.00
Substation MEER	0.26	2.30	0.71	0.00	2.10	0.21
Electrical	0.96	41.64	3.94	0.01	1.87	0.37
Wiring	0.27	11.14	0.48	0.00	0.29	0.04
Transformers	0.99	14.35	6.32	0.01	2.64	0.50
Maintenance Crew Equipment Check	0.12	1.14	0.12	0.00	0.86	0.08
Testing	0.11	1.03	0.10	0.00	0.39	0.03
Asphalting	4.82	16.58	28.54	0.04	4.80	1.68
Landscaping	1.96	9.05	15.14	0.02	3.02	0.87
Irrigation	2.15	8.53	5.09	0.01	1.10	0.46
Distribution Construction						
Civil	4.27	16.34	41.78	0.06	2.26	1.47
Electrical	3.43	14.15	26.75	0.04	1.53	0.97
Subtransmission Source Line Construction						
Survey	0.11	1.06	0.11	0.00	1.86	0.18
Marshalling Yard	0.83	3.90	6.35	0.01	0.43	0.21
Right-of-Way Clearing	4.66	18.07	41.67	0.06	40.55	7.27
Roads and Landing Work	10.70	41.75	111.05	0.15	177.53	24.43
Guard Structure Installation	5.29	20.79	46.19	0.07	20.86	3.57
Existing Wood Poles Removal	3.60	14.07	30.02	0.05	11.11	2.12
Tubular Steel Pole Foundations Installation	6.00	24.73	62.29	0.10	76.11	9.56
Wood Pole Installation	2.65	11.54	20.55	0.03	5.20	1.21
Steel Pole Haul	1.26	5.71	10.25	0.01	6.05	0.91
Steel Pole Assembly	1.89	9.29	12.86	0.02	4.93	0.98
Steel Pole Erection	1.89	9.29	12.86	0.02	4.93	0.98
Conductor Installation	5.54	25.36	52.62	0.08	36.36	5.06
Guard Structure Removal	3.62	14.62	32.34	0.04	16.61	2.71
Restoration	5.46	21.03	48.99	0.07	31.32	6.51
Telecommunications Construction						
Control Building Communications Room	0.24	2.27	0.45	0.00	0.26	0.02
Overhead Cable Installation	2.74	12.72	29.52	0.04	66.39	7.38
Underground Facility Installation	1.14	6.33	5.54	0.01	0.80	0.42
Underground Cable Installation	2.95	12.25	28.20	0.05	1.28	0.90
Optical Systems Installation at Other Locations	0.57	5.51	0.56	0.01	0.64	0.04
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.38	0.03
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42

Notes:
VOC = volatile organic compounds
CO = carbon monoxide
NOX = nitrogen oxides
SOX = sulfur oxides
PM10 = suspended particulate matter measuring less than 10 microns
PM2.5 = suspended particulate matter measuring less than 2.5 micron
lb/day = pounds per day
MEER = mechanical and electrical equipment room

Table 2
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions for Overlapping Construction Phases

Group[a]	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	1.08	0.10
Grading	11.63	52.09	117.60	0.16	33.18	9.46
Civil, Fencing	4.43	31.15	35.96	0.06	8.36	2.48
MEER, Electrical, Wiring, Transformers, Equipment Check, Testing, Asphalting, Landscaping, Irrigation	9.48	97.23	55.35	0.09	15.97	3.80
Maximum	**11.63**	**97.23**	**117.60**	**0.16**	**33.18**	**9.46**
Distribution Construction						
All	7.70	30.49	68.54	0.11	3.79	2.45
Maximum	**7.70**	**30.49**	**68.54**	**0.11**	**3.79**	**2.45**
Subtransmission Source Line Construction						
Marshalling Yard, Survey	0.94	4.95	6.46	0.01	2.29	0.39
Marshalling Yard, Right-of-Way Clearing, Roads and Landing Work	16.19	63.72	159.07	0.22	218.51	31.90
Marshalling Yard, Tubular Steel Pole Foundations Installation, Steel Pole Haul, Steel Pole Assembly, Steel Pole Erection, Wood Pole Installation	14.52	64.47	125.15	0.19	97.65	13.84
Marshalling Yard, Steel Pole Erection, Wood Pole Installation, Guard Structure Installation	10.66	45.52	85.94	0.14	31.42	5.97
Marshalling Yard, Existing Wood Poles Removal, Guard Structure Installation	9.73	38.76	82.56	0.13	32.40	5.90
Marshalling Yard, Conductor Installation	6.38	29.26	58.97	0.09	36.80	5.27
Marshalling Yard, Guard Structure Removal	4.45	18.52	38.70	0.06	17.05	2.92
Marshalling Yard, Restoration	6.30	24.93	55.34	0.08	31.76	6.72
Maximum	**16.19**	**64.47**	**159.07**	**0.22**	**218.51**	**31.90**
Telecommunications Construction						
All	7.40	36.81	63.82	0.11	69.11	8.74
Maximum	**7.40**	**36.81**	**63.82**	**0.11**	**69.11**	**8.74**
CONSTRUCTION MAXIMUM DAILY[b]	**42.91**	**229.00**	**409.03**	**0.59**	**324.60**	**52.55**
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.38	0.03
Maximum	**1.47**	**30.96**	**10.40**	**0.02**	**0.99**	**0.67**
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42
Maximum	**3.47**	**14.63**	**30.57**	**0.04**	**1.53**	**1.42**
DEMOLITION MAXIMUM DAILY[c]	**3.47**	**30.96**	**30.57**	**0.04**	**1.53**	**1.42**
PEAK DAILY[d]	**42.91**	**229.00**	**409.03**	**0.59**	**324.60**	**52.55**

[a] The construction phases within a group could all occur at the same time.

[b] Construction maximum daily emissions are the sum of the maximum daily emissions during construction of the substation, the distribution facilities, the subtransmission source lines and the telecommunications facilities, since construction of all of these components could occur at the same time.

[c] Demolition maximum daily emissions are the maximum daily emissions during demolition of the Nuevo Substation or the Model P.T. Substation.

[d] Peak daily emissions are the greater of the maximum daily emissions during construction and during demolition, since demolition would occur after construction is completed.

Table 3
Construction Emissions Summary
Onsite Daily Criteria Pollutant Emissions by Construction Phase

Phase	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.00	0.02	0.00	0.00	0.87	0.09
Grading	4.04	17.30	33.07	0.04	26.13	5.90
Fencing	0.39	2.26	2.88	0.00	2.61	0.45
Civil	1.90	16.30	14.92	0.02	4.14	1.25
Substation MEER	0.00	0.03	0.03	0.00	1.85	0.19
Electrical	0.46	36.83	3.45	0.00	1.31	0.34
Wiring	0.03	8.84	0.24	0.00	0.03	0.02
Transformers	0.68	11.38	6.02	0.01	2.29	0.48
Maintenance Crew Equipment Check	0.00	0.01	0.00	0.00	0.73	0.07
Testing	0.00	0.00	0.00	0.00	0.27	0.03
Asphalting	2.99	7.49	9.69	0.01	3.08	0.89
Landscaping	0.61	2.00	1.87	0.00	1.73	0.31
Irrigation	1.80	5.21	4.75	0.01	0.71	0.43
Distribution Construction						
Civil	2.99	9.44	29.38	0.04	1.08	0.96
Electrical	2.86	9.51	24.58	0.03	0.95	0.88
Subtransmission Source Line Construction						
Survey	0.00	0.00	0.00	0.00	0.00	0.00
Marshalling Yard	0.64	2.06	6.17	0.01	0.22	0.20
Right-of-Way Clearing	4.21	14.78	38.96	0.05	23.22	5.46
Roads and Landing Work	5.45	18.42	50.75	0.07	37.97	8.42
Guard Structure Installation	4.74	16.75	43.06	0.07	1.71	1.58
Existing Wood Poles Removal	3.19	10.67	28.32	0.04	1.18	1.09
Tubular Steel Pole Foundations Installation	2.91	10.27	28.44	0.05	1.09	0.92
Wood Pole Installation	2.19	7.31	19.55	0.02	0.86	0.78
Steel Pole Haul	0.98	3.41	9.20	0.01	0.34	0.32
Steel Pole Assembly	1.43	5.06	11.86	0.01	0.59	0.54
Steel Pole Erection	1.43	5.06	11.86	0.01	0.59	0.54
Conductor Installation	4.23	15.33	45.87	0.06	1.53	1.41
Guard Structure Removal	3.11	10.75	29.77	0.04	1.20	1.10
Restoration	5.01	17.22	47.39	0.06	22.28	5.57
Telecommunications Construction						
Control Building Communications Room	0.00	0.00	0.00	0.00	0.00	0.00
Overhead Cable Installation	2.26	8.67	27.79	0.04	0.86	0.79
Underground Facility Installation	0.84	3.53	5.17	0.01	0.47	0.40
Underground Cable Installation	2.65	9.44	27.82	0.04	0.95	0.87
Optical Systems Installation at Other Locations	0.00	0.00	0.00	0.00	0.00	0.00
Nuevo Substation Demolition						
Civil	0.91	4.55	6.14	0.01	0.52	0.48
Electrical	0.54	28.48	4.04	0.00	0.27	0.25
Maintenance Crew Equipment Check	0.00	0.00	0.00	0.00	0.00	0.00
Testing	0.00	0.00	0.00	0.00	0.27	0.03
Model P.T. Substation Demolition						
Civil	0.61	2.87	3.99	0.00	0.35	0.32
Electrical	3.07	11.22	29.09	0.04	1.16	1.07

Table 4
Construction Emissions Summary
Total Daily Onsite Criteria Pollutant Emissions for Overlapping Construction Phases

Group[a]	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.00	0.02	0.00	0.00	0.87	0.09
Grading	4.04	17.30	33.07	0.04	26.13	5.90
Civil, Fencing	2.30	18.56	17.80	0.02	6.75	1.70
MEER, Electrical, Wiring, Transformers, Equipment Check, Testing, Asphalting, Landscaping, Irrigation	6.58	71.79	26.06	0.03	11.99	2.75
Maximum Substation Construction	**6.58**	**71.79**	**33.07**	**0.04**	**26.13**	**5.90**
Distribution Construction						
Civil	2.99	9.44	29.38	0.04	1.08	0.96
Electrical	2.86	9.51	24.58	0.03	0.95	0.88
Maximum	**2.99**	**9.51**	**29.38**	**0.04**	**1.08**	**0.96**
Subtransmission Source Line Construction[b]						
Survey	0.00	0.00	0.00	0.00	0.00	0.00
Marshalling Yard	0.64	2.06	6.17	0.01	0.22	0.20
Guard Structure Installation	1.19	4.19	10.76	0.02	0.43	0.39
Existing Wood Poles Removal	0.32	1.07	2.83	0.00	0.12	0.11
Tubular Steel Pole Foundations Installation	2.91	10.27	28.44	0.05	1.09	0.92
Wood Pole Installation	0.55	1.83	4.89	0.01	0.21	0.19
Steel Pole Haul	0.25	0.85	2.30	0.00	0.09	0.08
Steel Pole Assembly	0.48	1.69	3.95	0.00	0.20	0.18
Steel Pole Erection	0.48	1.69	3.95	0.00	0.20	0.18
Conductor Installation	1.41	5.11	15.29	0.02	0.51	0.47
Guard Structure Removal	0.78	2.69	7.44	0.01	0.30	0.28
Maximum	**2.91**	**10.27**	**28.44**	**0.05**	**1.09**	**0.92**
Telecommunications Construction						
Control Building Communications Room	0.00	0.00	0.00	0.00	0.00	0.00
Overhead Cable Installation	2.26	8.67	27.79	0.04	0.86	0.79
Underground Facility Installation	0.84	3.53	5.17	0.01	0.47	0.40
Underground Cable Installation	2.65	9.44	27.82	0.04	0.95	0.87
Optical Systems Installation at Other Locations	0.00	0.00	0.00	0.00	0.00	0.00
Maximum	**2.65**	**9.44**	**27.82**	**0.04**	**0.95**	**0.87**
Nuevo Substation Demolition						
Civil	0.91	4.55	6.14	0.01	0.52	0.48
Electrical	0.54	28.48	4.04	0.00	0.27	0.25
Maintenance Crew Equipment Check	0.00	0.00	0.00	0.00	0.00	0.00
Testing	0.00	0.00	0.00	0.00	0.27	0.03
Maximum	**0.91**	**28.48**	**6.14**	**0.01**	**0.52**	**0.48**
Model P.T. Substation Demolition						
Civil	0.61	2.87	3.99	0.00	0.35	0.32
Electrical	3.07	11.22	29.09	0.04	1.16	1.07
Maximum	**3.07**	**11.22**	**29.09**	**0.04**	**1.16**	**1.07**

[a] The construction phases within a group could all occur at the same time at the same location.

The following Subtransmission Source Line construction activity emissions were divided by the following number of working locations per day:

- Guard Structure Installation: 4 structures per day
- Existing Wood Poles Removal: 10 poles per day
- Tubular Steel Pole Foundations Installation: 1 foundation per day
- Wood Pole Installation: 4 poles per day
- Steel Pole Haul: 4 locations per day
- Steel Pole Assembly: 3 poles per day
- Steel Pole Erection: 3 poles per day
- Conductor Installation: 1 pull, 1 tension and 1 splicing site per day
- Guard Structure Removal: 4 structures per day

[b] Right-of-way clearing, roads and landing work, and restoration were excluded from the LST analysis because these activities would occur over a distance of approximately 1 mile along the Proposed Subtransmission Source Line Route, instead of at a single location, each day.

Table 5
Construction Emissions
Localized Significance Threshold Analysis

Pollutant	Daily Onsite Emissions (lb/day)	Receptor Distance (m)	Allowable Emissions Interpolation[a] Distance 1 (m)	Emissions 1 (lb/day)	Distance 2 (m)	Emissions 2 (lb/day)	Interpolated Emissions (lb/day)[b]	Allowable Exceeded?
Substation Construction[c]								
CO	72	40	25	1,577	50	2,178	1,938	No
NOx	33	40	25	270	50	302	289	No
PM10	26	40	25	13	50	40	29	No
PM2.5	6	40	25	8	50	10	9	No
Distribution Construction[d]								
CO	10	40	25	602	50	887	773	No
NOx	29	40	25	118	50	148	136	No
PM10	1	40	25	4	50	12	9	No
PM2.5	1	40	25	3	50	4	4	No
Subtransmission Source Line Construction[d]								
CO	10	25	25	602	50	887	602	No
NOx	28	25	25	118	50	148	118	No
PM10	1	25	25	4	50	12	4	No
PM2.5	1	25	25	3	50	4	3	No
Telecommunications Construction[d]								
CO	9	40	25	602	50	887	773	No
NOx	28	40	25	118	50	148	136	No
PM10	1	40	25	4	50	12	9	No
PM2.5	1	40	25	3	50	4	4	No
Nuevo Substation Demolition[d]								
CO	28	60	50	887	100	1,746	1,059	No
NOx	6	60	50	148	100	212	161	No
PM10	1	60	50	12	100	30	16	No
PM2.5	0	60	50	4	100	8	5	No
Model P.T. Substation Demolition[d]								
CO	11	60	50	887	100	1,746	1,059	No
NOx	29	60	50	148	100	212	161	No
PM10	1	60	50	12	100	30	16	No
PM2.5	1	60	50	4	100	8	5	No

[a] Allowable emissions are from Appendix C to Final Localized Significance Methodology, SCAQMD, revised October 2009, downloaded from http://www.aqmd.gov/ceqa/handbook/LST/LST.html

[b] Interpolated emissions = Emissions 1 + (Receptor distance - Distance 1) x (Emissions 2 - Emissions 1) / (Distance 2 - Distance 1)

[c] Closest receptor is a residence. Allowable emissions are for a 5 acre site

[d] Closest receptor is a residence. Allowable emissions are for a 1 acre site.

Table 6
Construction Emissions Summary
Total Greenhouse Gas Emissions by Construction Phase

Phase	CO2e (MT)
Substation Construction	
Survey	1.21
Grading	652.98
Fencing	3.15
Civil	72.97
Substation MEER	3.16
Electrical	37.09
Wiring	4.41
Transformers	15.09
Maintenance Crew Equipment Check	2.24
Testing	5.38
Asphalting	26.24
Landscaping	16.05
Irrigation	8.62
Distribution Construction	
Civil	41.77
Electrical	76.99
Subtransmission Source Line Construction	
Survey	0.35
Marshalling Yard	171.54
Right-of-Way Clearing	36.21
Roads and Landing Work	96.37
Guard Structure Installation	6.52
Existing Wood Poles Removal	1.97
Tubular Steel Pole Foundations Installation	151.36
Wood Pole Installation	25.67
Steel Pole Haul	3.34
Steel Pole Assembly	5.30
Steel Pole Erection	5.30
Conductor Installation	37.04
Guard Structure Removal	3.93
Restoration	11.95
Telecommunications Construction	
Control Building Communications Room	1.36
Overhead Cable Installation	83.44
Underground Facility Installation	8.77
Underground Cable Installation	12.59
Optical Systems Installation at Other Locations	4.32
Nuevo Substation Demolition	
Civil	3.55
Electrical	2.72
Maintenance Crew Equipment Check	0.13
Testing	0.13
Model P.T. Substation Demolition	
Civil	1.95
Electrical	41.92
Total	**1,685.07**

Table 7
Substation Construction Emissions
Survey

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.02	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.87	0.09	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.02**	**0.00**	**0.00**	**0.87**	**0.09**	**0.0**
Offsite Motor Vehicle Exhaust	0.19	1.84	0.19	0.00	0.02	0.01	1.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.19	0.00	
Offsite Total	**0.19**	**1.84**	**0.19**	**0.00**	**0.21**	**0.01**	**1.2**
Total	**0.19**	**1.85**	**0.19**	**0.00**	**1.08**	**0.10**	**1.2**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]
None		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Survey Truck	2	10	N/A	1
Offsite				
Survey Truck	2	10	N/A	60
Worker Commute	2	10	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									

Table 7
Substation Construction Emissions
Survey

Survey Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Survey Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Survey Truck	0.00	0.02	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Survey Truck	0.10	0.92	0.09	0.00	0.01	0.01
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01
Offsite Total	**0.19**	**1.84**	**0.19**	**0.00**	**0.02**	**0.01**
Total	**0.19**	**1.85**	**0.19**	**0.00**	**0.02**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Survey Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Survey Truck	0.6	0.0	0.6
Worker Commute	0.6	0.0	0.6
Offsite Total	**1.2**	**0.0**	**1.2**
Total	**1.2**	**0.0**	**1.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Survey Truck	2	Unpaved	1	0.435	0.043	0.87	0.09
Onsite Total						**0.87**	**0.09**
Offsite							
Survey Truck	2	Paved	60	0.001	0.000	0.10	0.00
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**0.19**	**0.00**
Total						**1.06**	**0.09**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 8
Substation Construction Emissions
Grading

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	4.02	17.22	32.87	0.04	1.69	1.55	143.3
Onsite Motor Vehicle Exhaust	0.02	0.08	0.20	0.00	0.01	0.01	1.2
Onsite Motor Vehicle Fugitive PM	--	--	--	--	6.86	0.69	
Earthwork Fugitive PM	--	--	--	--	17.57	3.65	
Onsite Total	**4.04**	**17.30**	**33.07**	**0.04**	**26.13**	**5.90**	**144.5**
Offsite Motor Vehicle Exhaust	7.59	34.79	84.52	0.12	4.14	3.56	508.5
Offsite Motor Vehicle Fugitive PM	--	--	--	--	2.91	0.00	
Offsite Total	**7.59**	**34.79**	**84.52**	**0.12**	**7.05**	**3.56**	**508.5**
Total	**11.63**	**52.09**	**117.60**	**0.16**	**33.18**	**9.46**	**653.0**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Dozer	305	1	90	4
Loader	147	2	90	4
Scraper	267	1	90	3
Grader	110	1	90	3
4x4 Backhoe	79	2	90	2
4x4 Tamper	174	1	90	2

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Dozer	305	0.266	1.022	2.391	0.003	0.094	0.087	259.229	0.024	Crawler Tractors
Loader	147	0.131	0.629	1.013	0.001	0.058	0.054	106.315	0.012	Rubber Tired Loaders
Scraper	267	0.333	1.300	3.016	0.003	0.119	0.110	321.429	0.030	Scrapers
Grader	110	0.135	0.536	0.822	0.001	0.074	0.068	74.965	0.012	Graders
4x4 Backhoe	79	0.076	0.356	0.491	0.001	0.043	0.040	51.728	0.007	Tractors/Loaders/Backhoes
4x4 Tamper	174	0.101	0.588	0.860	0.001	0.047	0.043	106.516	0.009	Other Construction Equipment

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Dozer	1.06	4.09	9.57	0.01	0.38	0.35
Loader	1.05	5.03	8.11	0.01	0.47	0.43
Scraper	1.00	3.90	9.05	0.01	0.36	0.33
Grader	0.40	1.61	2.47	0.00	0.22	0.20
4x4 Backhoe	0.30	1.42	1.96	0.00	0.17	0.16
4x4 Tamper	0.20	1.18	1.72	0.00	0.09	0.09
Total	**4.02**	**17.22**	**32.87**	**0.04**	**1.69**	**1.55**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Dozer	42.3	0.0	42.4
Loader	34.7	0.0	34.8
Scraper	39.4	0.0	39.4
Grader	9.2	0.0	9.2
4x4 Backhoe	17.4	0.0	17.4
4x4 Tamper	0.0	0.0	0.0
Total	**143.0**	**0.0**	**143.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Water Truck	1	90	N/A	2
Tool Truck	1	90	N/A	1
Pickup 4x4	1	90	N/A	1
Dump Truck	45	90	N/A	0.1
Offsite				
Water Truck	1	90	N/A	10
Tool Truck	1	90	N/A	14

Table 8
Substation Construction Emissions
Grading

Pickup 4x4	1	90	N/A	14
Dump Truck	45	90	N/A	60
Worker Commute	15	90	N/A	60

[a] Dump trucks based on 40,000 CY import/export over 90 days and 10 CY/truck = 40,000 / 90 / 10 = 44.4

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Tool Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Pickup 4x4	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Tool Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Water Truck	0.01	0.02	0.06	0.00	0.00	0.00
Tool Truck	0.00	0.01	0.00	0.00	0.00	0.00
Pickup 4x4	0.00	0.01	0.00	0.00	0.00	0.00
Dump Truck	0.01	0.05	0.14	0.00	0.01	0.01
Onsite Total	**0.02**	**0.08**	**0.20**	**0.00**	**0.01**	**0.01**
Offsite						
Water Truck	0.03	0.10	0.31	0.00	0.01	0.01
Tool Truck	0.01	0.11	0.01	0.00	0.00	0.00
Pickup 4x4	0.01	0.11	0.01	0.00	0.00	0.00
Dump Truck	6.82	27.58	83.49	0.11	4.04	3.49
Worker Commute	0.72	6.89	0.70	0.01	0.08	0.05
Offsite Total	**7.59**	**34.79**	**84.52**	**0.12**	**4.14**	**3.56**
Total	**7.61**	**34.87**	**84.73**	**0.12**	**4.15**	**3.57**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Water Truck	0.3	0.0	0.3
Tool Truck	0.0	0.0	0.0
Pickup 4x4	0.0	0.0	0.0
Dump Truck	0.8	0.0	0.8
Onsite Total	**1.2**	**0.0**	**1.2**
Offsite			
Water Truck	1.7	0.0	1.7
Tool Truck	0.6	0.0	0.6
Pickup 4x4	0.6	0.0	0.6
Dump Truck	464.7	0.0	465.0
Worker Commute	40.5	0.0	40.5
Offsite Total	**508.1**	**0.0**	**508.5**
Total	**509.4**	**0.0**	**509.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Water Truck	1	Unpaved	2	0.922	0.092	1.84	0.18
Tool Truck	1	Unpaved	1	0.435	0.043	0.43	0.04
Pickup 4x4	1	Unpaved	1	0.435	0.043	0.43	0.04
Dump Truck	45	Unpaved	0.1	0.922	0.092	4.15	0.42
Onsite Total						**6.86**	**0.69**
Offsite							
Water Truck	1	Paved	10	0.001	0.000	0.01	0.00
Tool Truck	1	Paved	14	0.001	0.000	0.01	0.00
Pickup 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Dump Truck	45	Paved	60	0.001	0.000	2.16	0.00
Worker Commute	15	Paved	60	0.001	0.000	0.72	0.00
Offsite Total						**2.91**	**0.00**

Table 8
Substation Construction Emissions
Grading

Total						**9.78**	**0.69**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	450	1.62E-03	3.36E-04	0.73	0.15
Bulldozing, Scraping and Grading	hr/day	10	1.481	0.308	14.81	3.08
Storage Pile Wind Erosion[d]	acres	0.13	15.7	3.26	2.04	0.42
Total					**17.57**	**3.65**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Peak daily estimated from total of 40,000 CY over 90 days
[d] Based on 225 CY in each of two cones 7 ft. tall x 58 ft. diameter

Table 9
Substation Construction Emissions
Fencing

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.39	2.22	2.83	0.00	0.23	0.21	1.6
Onsite Motor Vehicle Exhaust	0.01	0.05	0.05	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	2.38	0.24	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.39**	**2.26**	**2.88**	**0.00**	**2.61**	**0.45**	**1.6**
Offsite Motor Vehicle Exhaust	0.25	2.27	0.67	0.00	0.04	0.03	1.6
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.21	0.00	
Offsite Total	**0.25**	**2.27**	**0.67**	**0.00**	**0.25**	**0.03**	**1.6**
Total	**0.65**	**4.53**	**3.55**	**0.01**	**2.86**	**0.48**	**3.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Bobcat	75	1	10	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Bobcat	75	0.048	0.277	0.354	0.001	0.029	0.026	42.762	0.004	Skid Steer Loaders

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Bobcat	0.39	2.22	2.83	0.00	0.23	0.21
Total	**0.39**	**2.22**	**2.83**	**0.00**	**0.23**	**0.21**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Bobcat	1.6	0.0	1.6
Total	**1.6**	**0.0**	**1.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Flatbed Truck	1	10	N/A	2
Crewcab Truck	1	10	N/A	1
Offsite				
Flatbed Truck	1	10	N/A	14
Crewcab Truck	1	10	N/A	14
Worker Commute	4	10	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Flatbed Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Crewcab Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Offsite									
Flatbed Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Crewcab Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Flatbed Truck	0.00	0.03	0.03	0.00	0.00	0.00

Table 9
Substation Construction Emissions
Fencing

Crewcab Truck	0.00	0.02	0.02	0.00	0.00	0.00
Onsite Total	**0.01**	**0.05**	**0.05**	**0.00**	**0.00**	**0.00**
Offsite						
Flatbed Truck	0.03	0.22	0.24	0.00	0.01	0.01
Crewcab Truck	0.03	0.22	0.24	0.00	0.01	0.01
Worker Commute	0.19	1.84	0.19	0.00	0.02	0.01
Offsite Total	**0.25**	**2.27**	**0.67**	**0.00**	**0.04**	**0.03**
Total	**0.26**	**2.32**	**0.72**	**0.00**	**0.04**	**0.03**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Flatbed Truck	0.0	0.0	0.0
Crewcab Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Flatbed Truck	0.2	0.0	0.2
Crewcab Truck	0.2	0.0	0.2
Worker Commute	1.2	0.0	1.2
Offsite Total	**1.6**	**0.0**	**1.6**
Total	**1.6**	**0.0**	**1.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Flatbed Truck	1	Unpaved	2	0.922	0.092	1.84	0.18
Crewcab Truck	1	Unpaved	1	0.532	0.053	0.53	0.05
Onsite Total						**2.38**	**0.24**
Offsite							
Flatbed Truck	1	Paved	14	0.001	0.000	0.01	0.00
Crewcab Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	4	Paved	60	0.001	0.000	0.19	0.00
Offsite Total						**0.21**	**0.00**
Total						**2.59**	**0.24**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 10
Substation Construction Emissions
Civil

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	1.90	16.26	14.83	0.02	1.02	0.93	47.9
Onsite Motor Vehicle Exhaust	0.01	0.04	0.09	0.00	0.00	0.00	0.3
Onsite Motor Vehicle Fugitive PM	--	--	--	--	3.11	0.31	
Earthwork Fugitive PM	--	--	--	--	0.01	0.00	
Onsite Total	**1.90**	**16.30**	**14.92**	**0.02**	**4.14**	**1.25**	**48.2**
Offsite Motor Vehicle Exhaust	1.88	10.32	17.48	0.03	0.88	0.75	24.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.48	0.00	
Offsite Total	**1.88**	**10.32**	**17.48**	**0.03**	**1.36**	**0.75**	**24.7**
Total	**3.78**	**26.62**	**32.41**	**0.05**	**5.50**	**2.00**	**73.0**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Excavator	152	1	60	4
Foundation Auger	79	1	60	5
Backhoe	79	2	60	3
Skip Loader	75	1	60	3
Bobcat Skid Steer	75	2	60	3
Forklift	83	1	60	4
17-Ton Crane	125	1	45	2

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Excavator	152	0.129	0.668	0.961	0.001	0.057	0.052	112.222	0.012	Excavators
Foundation Auger	79	0.051	0.472	0.503	0.001	0.033	0.030	77.122	0.005	Bore/Drill Rigs
Backhoe	79	0.076	0.356	0.491	0.001	0.043	0.040	51.728	0.007	Tractors/Loaders/Backhoes
Skip Loader	75	0.048	0.277	0.354	0.001	0.029	0.026	42.762	0.004	Skid Steer Loaders
Bobcat Skid Steer	75	0.048	0.277	0.354	0.001	0.029	0.026	42.762	0.004	Skid Steer Loaders
Forklift	83	0.004	1.408	0.172	0.000	0.003	0.003	31.235	0.033	Forklifts-Propane
17-Ton Crane	125	0.109	0.484	0.826	0.001	0.048	0.044	80.345	0.010	Cranes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Excavator	0.52	2.67	3.85	0.01	0.23	0.21
Foundation Auger	0.26	2.36	2.51	0.00	0.16	0.15
Backhoe	0.46	2.13	2.95	0.00	0.26	0.24
Skip Loader	0.14	0.83	1.06	0.00	0.09	0.08
Bobcat Skid Steer	0.29	1.66	2.12	0.00	0.17	0.16
Forklift	0.02	5.63	0.69	0.00	0.01	0.01
17-Ton Crane	0.22	0.97	1.65	0.00	0.10	0.09
Total	**1.90**	**16.26**	**14.83**	**0.02**	**1.02**	**0.93**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Excavator	12.2	0.0	12.2
Foundation Auger	10.5	0.0	10.5
Backhoe	8.4	0.0	8.5
Skip Loader	3.5	0.0	3.5
Bobcat Skid Steer	13.1	0.0	13.2
Forklift	0.0	0.0	0.0
17-Ton Crane	0.0	0.0	0.0
Total	**47.8**	**0.0**	**47.9**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Dump Truck	1	60	N/A	1

Table 10
Substation Construction Emissions
Civil

Water Truck	1	60	N/A	1
Tool Truck	1	60	N/A	1
Concrete Truck	9	5	N/A	0.1
Offsite				
Water Truck	1	60	N/A	10
Concrete Truck	9	5	N/A	60
Tool Truck	1	60	N/A	14
Worker Commute	10	60	N/A	60

[a] Concrete trucks based on 445 CY over 5 days and 10 CY/truck = 445 / 5 / 10 = 8.9

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Tool Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Concrete Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Concrete Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Tool Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Dump Truck	0.00	0.01	0.03	0.00	0.00	0.00
Water Truck	0.00	0.01	0.03	0.00	0.00	0.00
Tool Truck	0.00	0.01	0.03	0.00	0.00	0.00
Concrete Truck	0.00	0.01	0.00	0.00	0.00	0.00
Onsite Total	**0.01**	**0.04**	**0.09**	**0.00**	**0.00**	**0.00**
Offsite						
Water Truck	0.03	0.10	0.31	0.00	0.01	0.01
Concrete Truck	1.36	5.52	16.70	0.02	0.81	0.70
Tool Truck	0.01	0.11	0.01	0.00	0.00	0.00
Worker Commute	0.48	4.59	0.47	0.01	0.05	0.03
Offsite Total	**1.88**	**10.32**	**17.48**	**0.03**	**0.88**	**0.75**
Total	**1.89**	**10.36**	**17.58**	**0.03**	**0.88**	**0.75**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Dump Truck	0.1	0.0	0.1
Water Truck	0.1	0.0	0.1
Tool Truck	0.1	0.0	0.1
Concrete Truck	0.0	0.0	0.0
Onsite Total	**0.3**	**0.0**	**0.3**
Offsite			
Water Truck	1.1	0.0	1.1
Concrete Truck	5.2	0.0	5.2
Tool Truck	0.4	0.0	0.4
Worker Commute	18.0	0.0	18.0
Offsite Total	**24.7**	**0.0**	**24.7**
Total	**25.1**	**0.0**	**25.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Dump Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Water Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Tool Truck	1	Unpaved	1	0.435	0.043	0.43	0.04
Concrete Truck	9	Unpaved	0.1	0.922	0.092	0.83	0.08
Onsite Total						**3.11**	**0.31**
Offsite							
Water Truck	1	Paved	10	0.001	0.000	0.01	0.00

Table 10
Substation Construction Emissions
Civil

Concrete Truck	9	Paved	60	0.001	0.000	0.43	0.00
Tool Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	10	Paved	60	0.001	0.000	0.48	0.00
Offsite Total						**0.48**	**0.00**
Total						**3.59**	**0.31**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	8	1.62E-03	3.36E-04	0.01	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.01**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Peak daily estimated from total of 450 CY over 60 days

Table 11
Substation Construction Emissions
Substation MEER

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.03	0.03	0.00	0.00	0.00	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	1.84	0.18	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.03**	**0.03**	**0.00**	**1.85**	**0.19**	**0.1**
Offsite Motor Vehicle Exhaust	0.25	2.27	0.67	0.00	0.04	0.03	3.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.21	0.00	
Offsite Total	**0.25**	**2.27**	**0.67**	**0.00**	**0.25**	**0.03**	**3.1**
Total	**0.26**	**2.30**	**0.71**	**0.00**	**2.10**	**0.21**	**3.2**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]
None		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Carry-all Truck	1	20	N/A	1
Stake Truck	1	20	N/A	1
Offsite				
Carry-all Truck	1	20	N/A	14
Stake Truck	1	20	N/A	14
Worker Commute	4	20	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]

Table 11
Substation Construction Emissions
Substation MEER

Onsite									
Carry-all Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Stake Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Offsite									
Carry-all Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Stake Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Carry-all Truck	0.00	0.02	0.02	0.00	0.00	0.00
Stake Truck	0.00	0.02	0.02	0.00	0.00	0.00
Onsite Total	**0.00**	**0.03**	**0.03**	**0.00**	**0.00**	**0.00**
Offsite						
Carry-all Truck	0.03	0.22	0.24	0.00	0.01	0.01
Stake Truck	0.03	0.22	0.24	0.00	0.01	0.01
Worker Commute	0.19	1.84	0.19	0.00	0.02	0.01
Offsite Total	**0.25**	**2.27**	**0.67**	**0.00**	**0.04**	**0.03**
Total	**0.26**	**2.30**	**0.71**	**0.00**	**0.04**	**0.03**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Carry-all Truck	0.0	0.0	0.0
Stake Truck	0.0	0.0	0.0
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Carry-all Truck	0.4	0.0	0.4
Stake Truck	0.4	0.0	0.4
Worker Commute	2.4	0.0	2.4
Offsite Total	**3.1**	**0.0**	**3.1**
Total	**3.2**	**0.0**	**3.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Carry-all Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Stake Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Onsite Total						**1.84**	**0.18**
Offsite							
Carry-all Truck	1	Paved	14	0.001	0.000	0.01	0.00
Stake Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	4	Paved	60	0.001	0.000	0.19	0.00
Offsite Total						**0.21**	**0.00**
Total						**2.06**	**0.18**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Table 11
Substation Construction Emissions
Substation MEER

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 12
Substation Construction Emissions
Electrical

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.46	36.82	3.45	0.00	0.25	0.23	15.0
Onsite Motor Vehicle Exhaust	0.00	0.02	0.00	0.00	0.00	0.00	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	1.06	0.11	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.46**	**36.83**	**3.45**	**0.00**	**1.31**	**0.34**	**15.1**
Offsite Motor Vehicle Exhaust	0.50	4.81	0.49	0.01	0.06	0.04	22.0
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.50	0.00	
Offsite Total	**0.50**	**4.81**	**0.49**	**0.01**	**0.56**	**0.04**	**22.0**
Total	**0.96**	**41.64**	**3.94**	**0.01**	**1.87**	**0.37**	**37.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Scissor Lift	25	2	70	3
Manlift	25	2	70	3
Reach Manlift	25	1	70	4
15-Ton Crane	125	1	70	3

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Scissor Lift	25	0.008	2.210	0.061	0.000	0.007	0.006	13.000	0.070	Aerial Lifts-Propane
Manlift	25	0.008	2.210	0.061	0.000	0.007	0.006	13.000	0.070	Aerial Lifts-Propane
Reach Manlift	25	0.008	2.210	0.061	0.000	0.007	0.006	13.000	0.070	Aerial Lifts-Propane
15-Ton Crane	125	0.109	0.484	0.826	0.001	0.048	0.044	80.345	0.010	Cranes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Scissor Lift	0.05	13.26	0.36	0.00	0.04	0.04
Manlift	0.05	13.26	0.36	0.00	0.04	0.04
Reach Manlift	0.03	8.84	0.24	0.00	0.03	0.02
15-Ton Crane	0.33	1.45	2.48	0.00	0.14	0.13
Total	**0.46**	**36.82**	**3.45**	**0.00**	**0.25**	**0.23**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Scissor Lift	2.5	0.0	2.8
Manlift	2.5	0.0	2.8
Reach Manlift	1.7	0.0	1.8
15-Ton Crane	7.7	0.0	7.7
Total	**14.3**	**0.0**	**15.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Crew Truck	2	70	N/A	1
Offsite				
Crew Truck	2	70	N/A	14
Worker Commute	10	70	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Table 12
Substation Construction Emissions
Electrical

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Crew Truck	0.00	0.02	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.02	0.21	0.02	0.00	0.00	0.00
Worker Commute	0.48	4.59	0.47	0.01	0.05	0.03
Offsite Total	**0.50**	**4.81**	**0.49**	**0.01**	**0.06**	**0.04**
Total	**0.50**	**4.82**	**0.49**	**0.01**	**0.06**	**0.04**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Crew Truck	0.1	0.0	0.1
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Crew Truck	1.0	0.0	1.0
Worker Commute	21.0	0.0	21.0
Offsite Total	**22.0**	**0.0**	**22.0**
Total	**22.0**	**0.0**	**22.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Crew Truck	2	Unpaved	1	0.532	0.053	1.06	0.11
Onsite Total						**1.06**	**0.11**
Offsite							
Crew Truck	2	Paved	14	0.001	0.000	0.02	0.00
Worker Commute	10	Paved	60	0.001	0.000	0.48	0.00
Offsite Total						**0.50**	**0.00**
Total						**1.57**	**0.11**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 13
Substation Construction Emissions
Wiring

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.03	8.84	0.24	0.00	0.03	0.02	0.7
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.03**	**8.84**	**0.24**	**0.00**	**0.03**	**0.02**	**0.7**
Offsite Motor Vehicle Exhaust	0.24	2.30	0.23	0.00	0.03	0.02	3.8
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.24	0.00	
Offsite Total	**0.24**	**2.30**	**0.23**	**0.00**	**0.27**	**0.02**	**3.8**
Total	**0.27**	**11.14**	**0.48**	**0.00**	**0.29**	**0.04**	**4.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Manlift	25	1	25	4

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Manlift	25	0.008	2.210	0.061	0.000	0.007	0.006	13.000	0.070	Aerial Lifts-Propane

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Manlift	0.03	8.84	0.24	0.00	0.03	0.02
Total	**0.03**	**8.84**	**0.24**	**0.00**	**0.03**	**0.02**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Manlift	0.6	0.0	0.7
Total	**0.6**	**0.0**	**0.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
Worker Commute	5	25	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None									
Offsite									
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.24**	**2.30**	**0.23**	**0.00**	**0.03**	**0.02**
Total	**0.24**	**2.30**	**0.23**	**0.00**	**0.03**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Table 13
Substation Construction Emissions
Wiring

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Worker Commute	3.7	0.0	3.8
Offsite Total	**3.7**	**0.0**	**3.8**
Total	**3.7**	**0.0**	**3.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None							
Onsite Total						**0.00**	**0.00**
Offsite							
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**0.24**	**0.00**
Total						**0.24**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 14
Substation Construction Emissions
Transformers

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.68	11.35	5.99	0.01	0.30	0.28	9.2
Onsite Motor Vehicle Exhaust	0.00	0.03	0.03	0.00	0.00	0.00	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	1.99	0.20	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.68**	**11.38**	**6.02**	**0.01**	**2.29**	**0.48**	**9.3**
Offsite Motor Vehicle Exhaust	0.31	2.97	0.30	0.00	0.03	0.02	5.8
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.31	0.00	
Offsite Total	**0.31**	**2.97**	**0.30**	**0.00**	**0.35**	**0.02**	**5.8**
Total	**0.99**	**14.35**	**6.32**	**0.01**	**2.64**	**0.50**	**15.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Crane	125	1	30	6
Forklift	25	1	30	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Crane	125	0.109	0.484	0.826	0.001	0.048	0.044	80.345	0.010	Cranes
Forklift	83	0.004	1.408	0.172	0.000	0.003	0.003	31.235	0.033	Forklifts-Propane

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Crane	0.65	2.90	4.96	0.01	0.29	0.26
Forklift	0.02	8.45	1.03	0.00	0.02	0.02
Total	**0.68**	**11.35**	**5.99**	**0.01**	**0.30**	**0.28**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Crane	6.6	0.0	6.6
Forklift	2.6	0.0	2.6
Total	**9.1**	**0.0**	**9.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Crew Truck	2	30	N/A	1
Low Bed Truck	1	30	N/A	1
Offsite				
Crew Truck	2	30	N/A	14
Worker Commute	6	30	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Low Bed Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]

Table 14
Substation Construction Emissions
Transformers

Onsite						
Crew Truck	0.00	0.02	0.00	0.00	0.00	0.00
Low Bed Truck	0.00	0.01	0.03	0.00	0.00	0.00
Onsite Total	**0.00**	**0.03**	**0.03**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.02	0.21	0.02	0.00	0.00	0.00
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.31**	**2.97**	**0.30**	**0.00**	**0.03**	**0.02**
Total	**0.31**	**3.00**	**0.33**	**0.00**	**0.04**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Crew Truck	0.0	0.0	0.0
Low Bed Truck	0.1	0.0	0.1
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Crew Truck	0.4	0.0	0.4
Worker Commute	5.4	0.0	5.4
Offsite Total	**5.8**	**0.0**	**5.8**
Total	**5.9**	**0.0**	**5.9**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Crew Truck	2	Unpaved	1	0.532	0.053	1.06	0.11
Low Bed Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Onsite Total						**1.99**	**0.20**
Offsite							
Crew Truck	2	Paved	14	0.001	0.000	0.02	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.31**	**0.00**
Total						**2.30**	**0.20**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 15
Substation Construction Emissions
Maintenance Crew Equipment Check

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.01	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.73	0.07	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.01**	**0.00**	**0.00**	**0.73**	**0.07**	**0.0**
Offsite Motor Vehicle Exhaust	0.12	1.13	0.11	0.00	0.01	0.01	2.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.12	0.00	
Offsite Total	**0.12**	**1.13**	**0.11**	**0.00**	**0.13**	**0.01**	**2.2**
Total	**0.12**	**1.14**	**0.12**	**0.00**	**0.86**	**0.08**	**2.2**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None										

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Maintenance Truck	2	30	N/A	0.5
Offsite				
Maintenance Truck	2	30	N/A	14
Worker Commute	2	30	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Maintenance Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Maintenance Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Maintenance Truck	0.00	0.01	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.01**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Maintenance Truck	0.02	0.21	0.02	0.00	0.00	0.00
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01

Table 15
Substation Construction Emissions
Maintenance Crew Equipment Check

Offsite Total	**0.12**	**1.13**	**0.11**	**0.00**	**0.01**	**0.01**
Total	**0.12**	**1.14**	**0.12**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Maintenance Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Maintenance Truck	0.4	0.0	0.4
Worker Commute	1.8	0.0	1.8
Offsite Total	**2.2**	**0.0**	**2.2**
Total	**2.2**	**0.0**	**2.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Maintenance Truck	2	Unpaved	0.5	0.726	0.073	0.73	0.07
Onsite Total						**0.73**	**0.07**
Offsite							
Maintenance Truck	2	Paved	14	0.001	0.000	0.02	0.00
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**0.12**	**0.00**
Total						**0.84**	**0.07**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 16
Substation Construction Emissions
Testing

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.27	0.03	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.27**	**0.03**	**0.0**
Offsite Motor Vehicle Exhaust	0.11	1.03	0.10	0.00	0.01	0.01	5.4
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.11	0.00	
Offsite Total	**0.11**	**1.03**	**0.10**	**0.00**	**0.12**	**0.01**	**5.4**
Total	**0.11**	**1.03**	**0.10**	**0.00**	**0.39**	**0.03**	**5.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None										

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.[a]
Onsite				
Crew Truck	1	80	N/A	0.5
Offsite				
Crew Truck	1	80	N/A	14
Worker Commute	2	80	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Crew Truck	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.01	0.11	0.01	0.00	0.00	0.00
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01

Table 16
Substation Construction Emissions
Testing

Offsite Total	**0.11**	**1.03**	**0.10**	**0.00**	**0.01**	**0.01**
Total	**0.11**	**1.03**	**0.10**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Crew Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crew Truck	0.6	0.0	0.6
Worker Commute	4.8	0.0	4.8
Offsite Total	**5.4**	**0.0**	**5.4**
Total	**5.4**	**0.0**	**5.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Crew Truck	1	Unpaved	0.5	0.532	0.053	0.27	0.03
Onsite Total						**0.27**	**0.03**
Offsite							
Crew Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**0.11**	**0.00**
Total						**0.37**	**0.03**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 17
Substation Construction Emissions
Asphalting

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.30	7.46	9.63	0.01	0.70	0.65	6.0
Onsite Motor Vehicle Exhaust	0.01	0.03	0.06	0.00	0.00	0.00	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	2.38	0.24	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Asphaltic Paving VOC	0.7	--	--	--	--	--	--
Onsite Total	**2.99**	**7.49**	**9.69**	**0.01**	**3.08**	**0.89**	**6.1**
Offsite Motor Vehicle Exhaust	1.83	9.10	18.86	0.03	0.93	0.80	20.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.79	0.00	
Offsite Total	**1.83**	**9.10**	**18.86**	**0.03**	**1.72**	**0.80**	**20.1**
Total	**4.82**	**16.58**	**28.54**	**0.04**	**4.80**	**1.68**	**26.2**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Paving Roller	46	2	15	4
Asphalt Paver	152	1	15	4
Tractor	45	1	15	3
Asphalt Curb Machine	35	1	15	3

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Paving Roller	46	0.110	0.299	0.268	0.000	0.026	0.024	25.983	0.010	Rollers
Asphalt Paver	152	0.186	0.783	1.449	0.001	0.082	0.075	128.285	0.017	Pavers
Tractor	45	0.101	0.330	0.303	0.000	0.027	0.025	30.347	0.009	Tractors/Loaders/Backhoes
Asphalt Curb Machine	35	0.124	0.312	0.259	0.000	0.028	0.026	23.927	0.011	Paving Equipment

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Paving Roller	0.88	2.40	2.14	0.00	0.21	0.19
Asphalt Paver	0.75	3.13	5.80	0.01	0.33	0.30
Tractor	0.30	0.99	0.91	0.00	0.08	0.07
Asphalt Curb Machine	0.37	0.94	0.78	0.00	0.08	0.08
Total	**2.30**	**7.46**	**9.63**	**0.01**	**0.70**	**0.65**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Paving Roller	1.4	0.0	1.4
Asphalt Paver	3.5	0.0	3.5
Tractor	0.6	0.0	0.6
Asphalt Curb Machine	0.5	0.0	0.5
Total	**6.0**	**0.0**	**6.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[b]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.[a]
Onsite				
Stake Truck	1	15	N/A	0.5
Dump Truck	1	15	N/A	0.5
Crew Truck	2	15	N/A	0.5
Asphalt Delivery Truck	4	15	N/A	0.1
Aggregate Base Delivery Truck	6	15	N/A	0.1
Offsite				
Crew Truck	2	15	N/A	14
Asphalt Delivery Truck	4	15	N/A	60
Aggregate Base Delivery Truck	6	15	N/A	60
Worker Commute	6	15	N/A	60

[a] Onsite travel based on 25% use at 10 mph average speed

[b] Asphalt delivery trucks based on 308 CY over 8 days and 10 CY/truck = 308 / 8 / 10 = 3.9

Table 17
Substation Construction Emissions
Asphalting

Aggregate base delivery trucks based on 370 CY over 7 days and 10 CY/truck = 370 / 7 / 10 = 5.3

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Stake Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Asphalt Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Aggregate Base Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Asphalt Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Aggregate Base Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Stake Truck	0.00	0.01	0.02	0.00	0.00	0.00
Dump Truck	0.00	0.01	0.02	0.00	0.00	0.00
Crew Truck	0.00	0.01	0.00	0.00	0.00	0.00
Asphalt Delivery Truck	0.00	0.00	0.01	0.00	0.00	0.00
Aggregate Base Delivery Truck	0.00	0.01	0.02	0.00	0.00	0.00
Onsite Total	**0.01**	**0.03**	**0.06**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.02	0.21	0.02	0.00	0.00	0.00
Asphalt Delivery Truck	0.61	2.45	7.42	0.01	0.36	0.31
Aggregate Base Delivery Truck	0.91	3.68	11.13	0.01	0.54	0.47
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**1.83**	**9.10**	**18.86**	**0.03**	**0.93**	**0.80**
Total	**1.83**	**9.13**	**18.92**	**0.03**	**0.94**	**0.80**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Stake Truck	0.0	0.0	0.0
Dump Truck	0.0	0.0	0.0
Crew Truck	0.0	0.0	0.0
Asphalt Delivery Truck	0.0	0.0	0.0
Aggregate Base Delivery Truck	0.0	0.0	0.0
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Crew Truck	0.2	0.0	0.2
Asphalt Delivery Truck	6.9	0.0	6.9
Aggregate Base Delivery Truck	10.3	0.0	10.3
Worker Commute	2.7	0.0	2.7
Offsite Total	**20.1**	**0.0**	**20.1**
Total	**20.2**	**0.0**	**20.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Stake Truck	1	Unpaved	0.5	0.922	0.092	0.46	0.05
Dump Truck	1	Unpaved	0.5	0.922	0.092	0.46	0.05
Crew Truck	2	Unpaved	0.5	0.532	0.053	0.53	0.05
Asphalt Delivery Truck	4	Unpaved	0.1	0.922	0.092	0.37	0.04
Aggregate Base Delivery Truck	6	Unpaved	0.1	0.922	0.092	0.55	0.06
Onsite Total						**2.38**	**0.24**
Offsite							
Crew Truck	2	Paved	14	0.001	0.000	0.02	0.00
Asphalt Delivery Truck	4	Paved	60	0.001	0.000	0.19	0.00
Aggregate Base Delivery Truck	6	Paved	60	0.001	0.000	0.29	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.79**	**0.00**

Table 17
Substation Construction Emissions
Asphalting

Total						**3.17**	**0.24**

a From Table 51

[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52

[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Asphaltic Paving VOC Emissions

Area Paved (acre/day)[a]	Emission Factor (lb/acre)[b]	VOC (lb/day)[c]
0.26	2.62	0.7

[a] Assumed 11,200 sq. ft. external driveway paved in one day

[b] From URBEMISS 2007 User's Guide, Appendix A,
http://www.urbemis.com/software/download.html

[c] Emissions [lb/day] = Emission factor [lb/acre] x Area paved [acre/day]

Table 18
Substation Construction Emissions
Landscaping

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.60	1.98	1.82	0.00	0.16	0.15	1.2
Onsite Motor Vehicle Exhaust	0.00	0.02	0.05	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	1.57	0.16	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.61**	**2.00**	**1.87**	**0.00**	**1.73**	**0.31**	**1.3**
Offsite Motor Vehicle Exhaust	1.35	7.05	13.27	0.02	0.66	0.56	14.8
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.62	0.00	
Offsite Total	**1.35**	**7.05**	**13.27**	**0.02**	**1.29**	**0.56**	**14.8**
Total	**1.96**	**9.05**	**15.14**	**0.02**	**3.02**	**0.87**	**16.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Tractor	45	1	15	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Tractor	45	0.101	0.330	0.303	0.000	0.027	0.025	30.347	0.009	Tractors/Loaders/Backhoes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Tractor	0.60	1.98	1.82	0.00	0.16	0.15
Total	**0.60**	**1.98**	**1.82**	**0.00**	**0.16**	**0.15**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Tractor	1.2	0.0	1.2
Total	**1.2**	**0.0**	**1.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Dump Truck	1	15	N/A	1
Crushed Rock Delivery Truck	7	15	N/A	0.1
Offsite				
Crushed Rock Delivery Truck	7	15	N/A	60
Worker Commute	6	15	N/A	60

[a] Crushed rock delivery trucks based on 1,050 CY over 15 days and 10 CY/truck = 1,050 / 15 / 10 = 7

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Crushed Rock Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Crushed Rock Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Dump Truck	0.00	0.01	0.03	0.00	0.00	0.00
Crushed Rock Delivery Truck	0.00	0.01	0.02	0.00	0.00	0.00

Table 18
Substation Construction Emissions
Landscaping

Onsite Total	**0.00**	**0.02**	**0.05**	**0.00**	**0.00**	**0.00**
Offsite						
Crushed Rock Delivery Truck	1.06	4.29	12.99	0.02	0.63	0.54
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**1.35**	**7.05**	**13.27**	**0.02**	**0.66**	**0.56**
Total	**1.35**	**7.06**	**13.32**	**0.02**	**0.66**	**0.57**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Dump Truck	0.0	0.0	0.0
Crushed Rock Delivery Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crushed Rock Delivery Truck	12.0	0.0	12.1
Worker Commute	2.7	0.0	2.7
Offsite Total	**14.7**	**0.0**	**14.8**
Total	**14.8**	**0.0**	**14.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Dump Truck	1	Unpaved	1	0.922	0.092	0.92	0.09
Crushed Rock Delivery Truck	7	Unpaved	0.1	0.922	0.092	0.65	0.06
Onsite Total						**1.57**	**0.16**
Offsite							
Crushed Rock Delivery Truck	7	Paved	60	0.001	0.000	0.34	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.62**	**0.00**
Total						**2.19**	**0.16**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 19
Substation Construction Emissions
Irrigation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	1.80	5.21	4.75	0.01	0.44	0.41	4.3
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.27	0.03	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**1.80**	**5.21**	**4.75**	**0.01**	**0.71**	**0.43**	**4.3**
Offsite Motor Vehicle Exhaust	0.35	3.32	0.34	0.00	0.04	0.02	4.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.35	0.00	
Offsite Total	**0.35**	**3.32**	**0.34**	**0.00**	**0.39**	**0.02**	**4.3**
Total	**2.15**	**8.53**	**5.09**	**0.01**	**1.10**	**0.46**	**8.6**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Bobcat	45	1	20	8
Trencher	33	1	20	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Bobcat	45	0.060	0.233	0.240	0.000	0.018	0.017	25.519	0.005	Skid Steer Loaders
Trencher	33	0.166	0.418	0.354	0.000	0.037	0.034	32.918	0.015	Trenchers

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Bobcat	0.48	1.87	1.92	0.00	0.14	0.13
Trencher	1.32	3.34	2.83	0.00	0.30	0.27
Total	**1.80**	**5.21**	**4.75**	**0.01**	**0.44**	**0.41**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Bobcat	1.9	0.0	1.9
Trencher	2.4	0.0	2.4
Total	**4.2**	**0.0**	**4.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[b]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Crew Truck	1	20	N/A	0.5
Offsite				
Crew Truck	1	20	N/A	14
Worker Commute	7	20	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Crew Truck	0.00	0.00	0.00	0.00	0.00	0.00

Table 19
Substation Construction Emissions
Irrigation

Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.01	0.11	0.01	0.00	0.00	0.00
Worker Commute	0.33	3.21	0.33	0.00	0.04	0.02
Offsite Total	**0.35**	**3.32**	**0.34**	**0.00**	**0.04**	**0.02**
Total	**0.35**	**3.33**	**0.34**	**0.00**	**0.04**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO_2 (MT)[a]	CH_4 (MT)[a]	CO_2e (MT)[b]
Onsite			
Crew Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crew Truck	0.1	0.0	0.1
Worker Commute	4.2	0.0	4.2
Offsite Total	**4.3**	**0.0**	**4.3**
Total	**4.3**	**0.0**	**4.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Crew Truck	1	Unpaved	0.5	0.532	0.053	0.27	0.03
Onsite Total						**0.27**	**0.03**
Offsite							
Crew Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	7	Paved	60	0.001	0.000	0.34	0.00
Offsite Total						**0.35**	**0.00**
Total						**0.61**	**0.03**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 20
Distribution Construction Emissions
Civil

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.99	9.44	29.38	0.04	1.03	0.94	32.6
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.06	0.01	
Onsite Total	**2.99**	**9.44**	**29.38**	**0.04**	**1.08**	**0.96**	**32.6**
Offsite Motor Vehicle Exhaust	1.28	6.90	12.40	0.02	0.60	0.52	9.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.58	0.00	
Offsite Total	**1.28**	**6.90**	**12.40**	**0.02**	**1.18**	**0.52**	**9.2**
Total	**4.27**	**16.34**	**41.78**	**0.06**	**2.26**	**1.47**	**41.8**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Backhoe	350	1	18	8
Roller	250	1	18	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Backhoe	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes
Roller	250	0.135	0.408	1.410	0.002	0.050	0.046	153.090	0.012	Rollers

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Backhoe	1.91	6.17	18.10	0.03	0.63	0.58
Roller	1.08	3.27	11.28	0.01	0.40	0.37
Total	**2.99**	**9.44**	**29.38**	**0.04**	**1.03**	**0.94**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Backhoe	22.5	0.0	22.6
Roller	10.0	0.0	10.0
Total	**32.5**	**0.0**	**32.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
Dump Truck	4	9	N/A	60
Delivery Truck	1	4	N/A	60
Concrete Truck	2	9	N/A	60
Worker Commute	5	18	N/A	60

[a] Dump truck based on 315 CY over 9 days and 10 CY/truck = 315 / 9 / 10 = 3.5
Concrete trucks based on 100 CY over 9 days and 10 CY/truck = 100 / 9 / 10 = 1.1

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Delivery Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Concrete Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Table 20
Distribution Construction Emissions
Civil

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Dump Truck	0.61	2.45	7.42	0.01	0.36	0.31
Delivery Truck	0.13	0.93	1.04	0.00	0.04	0.03
Concrete Truck	0.30	1.23	3.71	0.00	0.18	0.16
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**1.28**	**6.90**	**12.40**	**0.02**	**0.60**	**0.52**
Total	**1.28**	**6.90**	**12.40**	**0.02**	**0.60**	**0.52**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Dump Truck	4.1	0.0	4.1
Delivery Truck	0.3	0.0	0.3
Concrete Truck	2.1	0.0	2.1
Worker Commute	2.7	0.0	2.7
Offsite Total	**9.2**	**0.0**	**9.2**
Total	**9.2**	**0.0**	**9.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None						0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Dump Truck	4	Paved	60	0.001	0.000	0.19	0.00
Delivery Truck	1	Paved	60	0.001	0.000	0.05	0.00
Concrete Truck	2	Paved	60	0.001	0.000	0.10	0.00
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**0.58**	**0.00**
Total						**0.58**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	35	1.62E-03	3.36E-04	0.06	0.01
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.06**	**0.01**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on 315 CY over 9 days

Table 21
Distribution Construction Emissions
Electrical

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.86	9.51	24.58	0.03	0.95	0.88	61.8
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**2.86**	**9.51**	**24.58**	**0.03**	**0.95**	**0.88**	**61.8**
Offsite Motor Vehicle Exhaust	0.56	4.64	2.17	0.01	0.13	0.10	15.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.45	0.00	
Offsite Total	**0.56**	**4.64**	**2.17**	**0.01**	**0.58**	**0.10**	**15.2**
Total	**3.43**	**14.15**	**26.75**	**0.04**	**1.53**	**0.97**	**77.0**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Rodder Truck	35	1	42	8
Cable Dolly	9	1	42	8
Reel Truck	210	1	42	8
Boom Truck	235	1	42	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Rodder Truck	35	0.084	0.274	0.271	0.000	0.023	0.021	27.990	0.008	Other Construction Equipment
Cable Dolly	9	0.012	0.062	0.074	0.000	0.003	0.003	10.107	0.001	Other Construction Equipment
Reel Truck	210	0.152	0.543	1.657	0.002	0.055	0.050	254.238	0.014	Other Construction Equipment
Boom Truck	235	0.110	0.310	1.071	0.001	0.039	0.036	112.159	0.010	Cranes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Rodder Truck	0.67	2.19	2.17	0.00	0.18	0.17
Cable Dolly	0.09	0.49	0.59	0.00	0.02	0.02
Reel Truck	1.21	4.34	13.26	0.02	0.44	0.40
Boom Truck	0.88	2.48	8.57	0.01	0.31	0.29
Total	**2.86**	**9.51**	**24.58**	**0.03**	**0.95**	**0.88**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Rodder Truck	4.3	0.0	4.3
Cable Dolly	1.5	0.0	1.5
Reel Truck	38.7	0.0	38.8
Boom Truck	17.1	0.0	17.1
Total	**61.6**	**0.0**	**61.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
Rodder Truck	1	42	N/A	14
Reel Truck	1	42	N/A	14
Line Truck	1	42	N/A	14
Troubleman Truck	1	42	N/A	14
Boom Truck	1	42	N/A	14
Foreman Truck	1	42	N/A	14
Worker Commute	8	42	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]

Table 21
Distribution Construction Emissions
Electrical

Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Rodder Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Reel Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Line Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Troubleman Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Boom Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Foreman Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Rodder Truck	0.04	0.14	0.43	0.00	0.02	0.02
Reel Truck	0.04	0.14	0.43	0.00	0.02	0.02
Line Truck	0.03	0.22	0.24	0.00	0.01	0.01
Troubleman Truck	0.03	0.22	0.24	0.00	0.01	0.01
Boom Truck	0.04	0.14	0.43	0.00	0.02	0.02
Foreman Truck	0.01	0.11	0.01	0.00	0.00	0.00
Worker Commute	0.38	3.67	0.37	0.01	0.04	0.03
Offsite Total	**0.56**	**4.64**	**2.17**	**0.01**	**0.13**	**0.10**
Total	**0.56**	**4.64**	**2.17**	**0.01**	**0.13**	**0.10**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Rodder Truck	1.1	0.0	1.1
Reel Truck	1.1	0.0	1.1
Line Truck	0.7	0.0	0.7
Troubleman Truck	0.7	0.0	0.7
Boom Truck	1.1	0.0	1.1
Foreman Truck	0.3	0.0	0.3
Worker Commute	10.1	0.0	10.1
Offsite Total	**15.2**	**0.0**	**15.2**
Total	**15.2**	**0.0**	**15.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None						0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Rodder Truck	1	Paved	14	0.001	0.000	0.01	0.00
Reel Truck	1	Paved	14	0.001	0.000	0.01	0.00
Line Truck	1	Paved	14	0.001	0.000	0.01	0.00
Troubleman Truck	1	Paved	14	0.001	0.000	0.01	0.00
Boom Truck	1	Paved	14	0.001	0.000	0.01	0.00
Foreman Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	8	Paved	60	0.001	0.000	0.38	0.00
Offsite Total						**0.45**	**0.00**
Total						**0.45**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00

Table 21
Distribution Construction Emissions
Electrical

Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 22
Subtransmission Source Line Construction Emissions
Survey

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.0**
Offsite Motor Vehicle Exhaust	0.11	1.06	0.11	0.00	0.01	0.01	0.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	1.85	0.17	
Offsite Total	**0.11**	**1.06**	**0.11**	**0.00**	**1.86**	**0.18**	**0.3**
Total	**0.11**	**1.06**	**0.11**	**0.00**	**1.86**	**0.18**	**0.3**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
1/2-Ton Pick-up Truck, 4x4	1	5	N/A	18
Worker Commute	2	5	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
1/2-Ton Pick-up Truck, 4x4	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
1/2-Ton Pick-up Truck, 4x4	0.01	0.14	0.01	0.00	0.00	0.00
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01
Offsite Total	**0.11**	**1.06**	**0.11**	**0.00**	**0.01**	**0.01**
Total	**0.11**	**1.06**	**0.11**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Table 22
Subtransmission Source Line Construction Emissions
Survey

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
1/2-Ton Pick-up Truck, 4x4	0.0	0.0	0.0
Worker Commute	0.3	0.0	0.3
Offsite Total	**0.3**	**0.0**	**0.3**
Total	**0.3**	**0.0**	**0.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None							
Onsite Total						**0.00**	**0.00**
Offsite							
1/2-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1/2-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**1.85**	**0.17**
Total						**1.85**	**0.17**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 23
Subtransmission Source Line Construction Emissions
Marshalling Yard

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.62	1.96	6.00	0.01	0.21	0.19	123.7
Onsite Motor Vehicle Exhaust	0.02	0.10	0.16	0.00	0.01	0.01	4.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.01	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.64**	**2.06**	**6.17**	**0.01**	**0.22**	**0.20**	**127.7**
Offsite Motor Vehicle Exhaust	0.19	1.84	0.19	0.00	0.02	0.01	43.8
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.19	0.00	
Offsite Total	**0.19**	**1.84**	**0.19**	**0.00**	**0.21**	**0.01**	**43.8**
Total	**0.83**	**3.90**	**6.35**	**0.01**	**0.43**	**0.21**	**171.5**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
30-Ton Crane Truck	300	1	365	2
10,000 lb Rough Terrain Forklift	200	1	365	5

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
30-Ton Crane Truck	300	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
10,000 lb Rough Terrain Forklift	200	0.059	0.164	0.587	0.001	0.019	0.017	77.122	0.005	Forklifts

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
30-Ton Crane Truck	0.33	1.14	3.07	0.00	0.11	0.11
10,000 lb Rough Terrain Forklift	0.30	0.82	2.94	0.00	0.09	0.09
Total	**0.62**	**1.96**	**6.00**	**0.01**	**0.21**	**0.19**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
30-Ton Crane Truck	59.6	0.0	59.7
10,000 lb Rough Terrain Forklift	63.8	0.0	63.9
Total	**123.5**	**0.0**	**123.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.[a]
Onsite				
1-Ton Crew Cab, 4x4	1	365	2	5
Truck, Semi Tractor	1	365	1	2.5
Offsite				
Worker Commute	4	365	N/A	60

[a] Onsite travel based on 25% use at 10 mph average speed

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
1-Ton Crew Cab, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Truck, Semi Tractor	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						

Table 23
Subtransmission Source Line Construction Emissions
Marshalling Yard

1-Ton Crew Cab, 4x4	0.01	0.08	0.09	0.00	0.00	0.00
Truck, Semi Tractor	0.01	0.03	0.08	0.00	0.00	0.00
Onsite Total	**0.02**	**0.10**	**0.16**	**0.00**	**0.01**	**0.01**
Offsite						
Worker Commute	0.19	1.84	0.19	0.00	0.02	0.01
Offsite Total	**0.19**	**1.84**	**0.19**	**0.00**	**0.02**	**0.01**
Total	**0.21**	**1.94**	**0.35**	**0.00**	**0.03**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
1-Ton Crew Cab, 4x4	2.3	0.0	2.3
Truck, Semi Tractor	1.7	0.0	1.7
Onsite Total	**4.0**	**0.0**	**4.0**
Offsite			
Worker Commute	43.8	0.0	43.8
Offsite Total	**43.8**	**0.0**	**43.8**
Total	**47.8**	**0.0**	**47.9**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
1-Ton Crew Cab, 4x4	1	Paved	5	0.001	0.000	0.00	0.00
Truck, Semi Tractor	1	Paved	2.5	0.001	0.000	0.00	0.00
Onsite Total						**0.01**	**0.00**
Offsite							
Worker Commute	4	Paved	60	0.001	0.000	0.19	0.00
Offsite Total						**0.19**	**0.00**
Total						**0.20**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 24
Subtransmission Source Line Construction Emissions
Right-of-Way Clearing

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	4.20	14.74	38.84	0.05	1.44	1.32	31.8
Onsite Motor Vehicle Exhaust	0.01	0.04	0.12	0.00	0.01	0.01	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	3.69	0.37	
Earthwork Fugitive PM	--	--	--	--	18.09	3.76	
Onsite Total	**4.21**	**14.78**	**38.96**	**0.05**	**23.22**	**5.46**	**31.9**
Offsite Motor Vehicle Exhaust	0.46	3.29	2.71	0.01	0.14	0.12	4.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	17.18	1.69	
Offsite Total	**0.46**	**3.29**	**2.71**	**0.01**	**17.32**	**1.81**	**4.3**
Total	**4.66**	**18.07**	**41.67**	**0.06**	**40.55**	**7.27**	**36.2**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Road Grader	350	1	14	6
Backhoe/Front Loader	350	1	14	6
Track Type Dozer	350	1	14	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Road Grader	350	0.195	0.664	1.819	0.002	0.067	0.062	229.484	0.018	Graders
Backhoe/Front Loader	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes
Track Type Dozer	350	0.266	1.022	2.391	0.003	0.094	0.087	259.229	0.024	Crawler Tractors

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Road Grader	1.17	3.98	10.92	0.01	0.40	0.37
Backhoe/Front Loader	1.43	4.63	13.57	0.02	0.47	0.43
Track Type Dozer	1.60	6.13	14.35	0.02	0.57	0.52
Total	**4.20**	**14.74**	**38.84**	**0.05**	**1.44**	**1.32**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Road Grader	8.7	0.0	8.8
Backhoe/Front Loader	13.1	0.0	13.2
Track Type Dozer	9.9	0.0	9.9
Total	**31.8**	**0.0**	**31.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Water Truck	4	14	N/A	1
Offsite				
Water Truck	4	14	N/A	13
1-Ton Crew Cab, 4x4	1	14	N/A	18
Lowboy Truck/Trailer	1	14	N/A	18
Worker Commute	5	14	N/A	60

[a] Water trucks based on 16,000 gal water per day and 4,000 gal/truck = 16,000 / 4,000 = 4

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
1-Ton Crew Cab, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Lowboy Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

Table 24
Subtransmission Source Line Construction Emissions
Right-of-Way Clearing

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Water Truck	0.01	0.04	0.12	0.00	0.01	0.01
Onsite Total	**0.01**	**0.04**	**0.12**	**0.00**	**0.01**	**0.01**
Offsite						
Water Truck	0.13	0.53	1.61	0.00	0.08	0.07
1-Ton Crew Cab, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Lowboy Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.46**	**3.29**	**2.71**	**0.01**	**0.14**	**0.12**
Total	**0.47**	**3.33**	**2.83**	**0.01**	**0.15**	**0.12**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Water Truck	0.1	0.0	0.1
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Water Truck	1.4	0.0	1.4
1-Ton Crew Cab, 4x4	0.3	0.0	0.3
Lowboy Truck/Trailer	0.5	0.0	0.5
Worker Commute	2.1	0.0	2.1
Offsite Total	**4.3**	**0.0**	**4.3**
Total	**4.4**	**0.0**	**4.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Water Truck	4	Unpaved	1	0.922	0.092	3.69	0.37
Onsite Total						**3.69**	**0.37**
Offsite							
Water Truck	4	Paved	10	0.001	0.000	0.03	0.00
1-Ton Crew Cab, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Lowboy Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
Water Truck	4	Unpaved	3	0.922	0.092	11.07	1.11
1-Ton Crew Cab, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Lowboy Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**17.18**	**1.69**
Total						**20.87**	**2.06**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	200	1.62E-03	3.36E-04	0.32	0.07
Bulldozing, Scraping and Grading	hr/day	12	1.481	0.308	17.77	3.70
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**18.09**	**3.76**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on clearing 10,800 ft. long x 14' wide x 6" deep = 2,800 CY over 14 days

Table 25
Subtransmission Source Line Construction Emissions
Roads and Landing Work

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	5.43	18.34	50.51	0.07	1.85	1.70	41.7
Onsite Motor Vehicle Exhaust	0.02	0.08	0.25	0.00	0.01	0.01	0.2
Onsite Motor Vehicle Fugitive PM	--	--	--	--	7.38	0.74	
Earthwork Fugitive PM	--	--	--	--	28.73	5.98	
Onsite Total	**5.45**	**18.42**	**50.75**	**0.07**	**37.97**	**8.42**	**41.9**
Offsite Motor Vehicle Exhaust	5.25	23.33	60.30	0.08	2.91	2.51	54.4
Offsite Motor Vehicle Fugitive PM	--	--	--	--	136.65	13.49	
Offsite Total	**5.25**	**23.33**	**60.30**	**0.08**	**139.56**	**16.00**	**54.4**
Total	**10.70**	**41.75**	**111.05**	**0.15**	**177.53**	**24.43**	**96.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Road Grader	350	1	14	4
Backhoe/Front Loader	350	1	14	6
Drum Type Compactor	250	1	14	4
Track Type Dozer	350	1	14	6
Excavator	300	1	14	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Road Grader	350	0.195	0.664	1.819	0.002	0.067	0.062	229.484	0.018	Graders
Backhoe/Front Loader	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes
Drum Type Compactor	250	0.135	0.408	1.410	0.002	0.050	0.046	153.090	0.012	Rollers
Track Type Dozer	350	0.266	1.022	2.391	0.003	0.094	0.087	259.229	0.024	Crawler Tractors
Excavator	300	0.180	0.549	1.611	0.002	0.057	0.053	233.735	0.016	Excavators

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Road Grader	0.78	2.66	7.28	0.01	0.27	0.25
Backhoe/Front Loader	1.43	4.63	13.57	0.02	0.47	0.43
Drum Type Compactor	0.54	1.63	5.64	0.01	0.20	0.18
Track Type Dozer	1.60	6.13	14.35	0.02	0.57	0.52
Excavator	1.08	3.30	9.67	0.01	0.34	0.32
Total	**5.43**	**18.34**	**50.51**	**0.07**	**1.85**	**1.70**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Road Grader	5.8	0.0	5.8
Backhoe/Front Loader	13.1	0.0	13.2
Drum Type Compactor	3.9	0.0	3.9
Track Type Dozer	9.9	0.0	9.9
Excavator	8.9	0.0	8.9
Total	**41.6**	**0.0**	**41.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Water Truck	8	14	N/A	1
Offsite				
Water Truck	8	14	N/A	13
1-Ton Crew Cab, 4x4	1	14	N/A	18
Lowboy Truck/Trailer	1	14	N/A	18
Aggregate Base Delivery Truck	29	14	N/A	64
Worker Commute	5	14	N/A	60

[a] Water trucks based on 32,000 gal water per day and 4,000 gal/truck = 32,000 / 4,000 = 8

Table 25
Subtransmission Source Line Construction Emissions
Roads and Landing Work

Aggregate base delivery trucks based on 4,000 CY over 14 days and 10 CY/truck = 4,000 / 14 / 10 = 28.6

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Water Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Lowboy Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Aggregate Base Delivery Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Water Truck	0.02	0.08	0.25	0.00	0.01	0.01
Onsite Total	**0.02**	**0.08**	**0.25**	**0.00**	**0.01**	**0.01**
Offsite						
Water Truck	0.23	1.61	1.80	0.00	0.07	0.06
1-Ton Crew Cab, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Lowboy Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
Aggregate Base Delivery Truck	4.69	18.96	57.39	0.08	2.78	2.40
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**5.25**	**23.33**	**60.30**	**0.08**	**2.91**	**2.51**
Total	**5.27**	**23.41**	**60.54**	**0.08**	**2.92**	**2.52**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Water Truck	0.2	0.0	0.2
Onsite Total	**0.2**	**0.0**	**0.2**
Offsite			
Water Truck	1.8	0.0	1.8
1-Ton Crew Cab, 4x4	0.3	0.0	0.3
Lowboy Truck/Trailer	0.5	0.0	0.5
Aggregate Base Delivery Truck	49.7	0.0	49.7
Worker Commute	2.1	0.0	2.1
Offsite Total	**54.4**	**0.0**	**54.4**
Total	**54.6**	**0.0**	**54.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Water Truck	8	Unpaved	1	0.922	0.092	7.38	0.74
Onsite Total						**7.38**	**0.74**
Offsite							
Water Truck	8	Paved	10	0.001	0.000	0.06	0.00
1-Ton Crew Cab, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Lowboy Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
Aggregate Base Delivery Truck	29	Paved	60	0.001	0.000	1.39	0.00
Water Truck	8	Unpaved	3	0.922	0.092	22.13	2.21
1-Ton Crew Cab, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Lowboy Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
Aggregate Base Delivery Truck	29	Unpaved	4	0.922	0.092	106.98	10.70
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**136.65**	**13.49**
Total						**144.03**	**14.23**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Table 25
Subtransmission Source Line Construction Emissions
Roads and Landing Work

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	2,800	1.62E-03	3.36E-04	4.52	0.94
Bulldozing, Scraping and Grading	hr/day	10	1.481	0.308	14.81	3.08
Storage Pile Wind Erosion[d]	acres	0.6	15.7	3.26	9.40	1.96
Total					**28.73**	**5.98**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on excavating and backfilling 8.0 acres to 1.5' depth over 14 days
[d] Based on 8.0 acres total over 14 days

Table 26
Subtransmission Source Line Construction Emissions
Guard Structure Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	4.74	16.75	43.06	0.07	1.71	1.58	5.8
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**4.74**	**16.75**	**43.06**	**0.07**	**1.71**	**1.58**	**5.8**
Offsite Motor Vehicle Exhaust	0.55	4.05	3.13	0.01	0.16	0.13	0.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	18.98	1.86	
Offsite Total	**0.55**	**4.05**	**3.13**	**0.01**	**19.14**	**2.00**	**0.7**
Total	**5.29**	**20.79**	**46.19**	**0.07**	**20.86**	**3.57**	**6.5**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Compressor Trailer	120	1	2	6
Auger Truck	500	1	2	6
30-Ton Crane Truck	300	1	2	8
80ft. Hydraulic Manlift/Bucket Truck	350	1	2	4
Backhoe/Front Loader	350	1	2	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
Auger Truck	500	0.135	0.553	1.315	0.003	0.044	0.040	311.309	0.012	Bore/Drill Rigs
30-Ton Crane Truck	300	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
80ft. Hydraulic Manlift/Bucket Truck	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
Backhoe/Front Loader	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Compressor Trailer	0.53	1.97	3.20	0.00	0.30	0.27
Auger Truck	0.81	3.32	7.89	0.02	0.26	0.24
30-Ton Crane Truck	1.31	4.55	12.26	0.01	0.46	0.42
80ft. Hydraulic Manlift/Bucket Truck	0.65	2.28	6.13	0.01	0.23	0.21
Backhoe/Front Loader	1.43	4.63	13.57	0.02	0.47	0.43
Total	**4.74**	**16.75**	**43.06**	**0.07**	**1.71**	**1.58**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Compressor Trailer	0.3	0.0	0.3
Auger Truck	1.7	0.0	1.7
30-Ton Crane Truck	1.3	0.0	1.3
80ft. Hydraulic Manlift/Bucket Truck	0.7	0.0	0.7
Backhoe/Front Loader	1.9	0.0	1.9
Total	**5.8**	**0.0**	**5.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	2	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	2	N/A	18
Extendable Flat Bed Pole Truck	1	2	N/A	18
Auger Truck	1	2	N/A	18
30-Ton Crane Truck	1	2	N/A	18
80ft. Hydraulic Manlift/Bucket Truck	1	2	N/A	18
Worker Commute	6	2	N/A	60

Table 26
Subtransmission Source Line Construction Emissions
Guard Structure Installation

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Extendable Flat Bed Pole Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Auger Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
30-Ton Crane Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
80ft. Hydraulic Manlift/Bucket Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Extendable Flat Bed Pole Truck	0.05	0.18	0.56	0.00	0.03	0.02
Auger Truck	0.05	0.18	0.56	0.00	0.03	0.02
30-Ton Crane Truck	0.05	0.18	0.56	0.00	0.03	0.02
80ft. Hydraulic Manlift/Bucket Truck	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.55**	**4.05**	**3.13**	**0.01**	**0.16**	**0.13**
Total	**0.55**	**4.05**	**3.13**	**0.01**	**0.16**	**0.13**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.0	0.0	0.0
1-Ton Crew Cab Flat Bed, 4x4	0.0	0.0	0.0
Extendable Flat Bed Pole Truck	0.1	0.0	0.1
Auger Truck	0.1	0.0	0.1
30-Ton Crane Truck	0.1	0.0	0.1
80ft. Hydraulic Manlift/Bucket Truck	0.1	0.0	0.1
Worker Commute	0.4	0.0	0.4
Offsite Total	**0.7**	**0.0**	**0.7**
Total	**0.7**	**0.0**	**0.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None							
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Extendable Flat Bed Pole Truck	1	Paved	14	0.001	0.000	0.01	0.00
Auger Truck	1	Paved	14	0.001	0.000	0.01	0.00
30-Ton Crane Truck	1	Paved	14	0.001	0.000	0.01	0.00
80ft. Hydraulic Manlift/Bucket Truck	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Extendable Flat Bed Pole Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Auger Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
30-Ton Crane Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
80ft. Hydraulic Manlift/Bucket Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00

Table 26
Subtransmission Source Line Construction Emissions
Guard Structure Installation

Offsite Total						**18.98**	**1.86**
Total						**18.98**	**1.86**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 27
Subtransmission Source Line Construction Emissions
Existing Wood Poles Removal

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	3.19	10.67	28.32	0.04	1.18	1.09	1.7
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**3.19**	**10.67**	**28.32**	**0.04**	**1.18**	**1.09**	**1.7**
Offsite Motor Vehicle Exhaust	0.42	3.40	1.70	0.01	0.10	0.08	0.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	9.83	0.95	
Offsite Total	**0.42**	**3.40**	**1.70**	**0.01**	**9.92**	**1.03**	**0.3**
Total	**3.60**	**14.07**	**30.02**	**0.05**	**11.11**	**2.12**	**2.0**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
10-000 lb. Rough Terrain Forklift	200	1	1	4
30-Ton Crane Truck	300	1	1	6
Compressor Trailer	120	1	1	6
Backhoe/Front Loader	350	1	1	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
10-000 lb. Rough Terrain Forklift	200	0.059	0.164	0.587	0.001	0.019	0.017	77.122	0.005	Forklifts
30-Ton Crane Truck	300	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
Backhoe/Front Loader	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
10-000 lb. Rough Terrain Forklift	0.24	0.66	2.35	0.00	0.07	0.07
30-Ton Crane Truck	0.98	3.41	9.20	0.01	0.34	0.32
Compressor Trailer	0.53	1.97	3.20	0.00	0.30	0.27
Backhoe/Front Loader	1.43	4.63	13.57	0.02	0.47	0.43
Total	**3.19**	**10.67**	**28.32**	**0.04**	**1.18**	**1.09**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
10-000 lb. Rough Terrain Forklift	0.1	0.0	0.1
30-Ton Crane Truck	0.5	0.0	0.5
Compressor Trailer	0.1	0.0	0.1
Backhoe/Front Loader	0.9	0.0	0.9
Total	**1.7**	**0.0**	**1.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
1-Ton Crew Cab, 4x4	1	1	N/A	18
Flat Bed Truck/Trailer	1	1	N/A	18
30-Ton Crane Truck	1	1	N/A	18
Worker Commute	6	1	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									

Table 27
Subtransmission Source Line Construction Emissions
Existing Wood Poles Removal

1-Ton Crew Cab, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Flat Bed Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
30-Ton Crane Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
1-Ton Crew Cab, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Flat Bed Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
30-Ton Crane Truck	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.42**	**3.40**	**1.70**	**0.01**	**0.10**	**0.08**
Total	**0.42**	**3.40**	**1.70**	**0.01**	**0.10**	**0.08**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
1-Ton Crew Cab, 4x4	0.0	0.0	0.0
Flat Bed Truck/Trailer	0.0	0.0	0.0
30-Ton Crane Truck	0.0	0.0	0.0
Worker Commute	0.2	0.0	0.2
Offsite Total	**0.3**	**0.0**	**0.3**
Total	**0.3**	**0.0**	**0.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None							
Onsite Total						**0.00**	**0.00**
Offsite							
1-Ton Crew Cab, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Flat Bed Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
30-Ton Crane Truck	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Flat Bed Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
30-Ton Crane Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**9.83**	**0.95**
Total						**9.83**	**0.95**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 28
Subtransmission Source Line Construction Emissions
Tubular Steel Pole Foundations Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.91	10.27	28.44	0.05	0.97	0.89	73.6
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.12	0.03	
Onsite Total	**2.91**	**10.27**	**28.44**	**0.05**	**1.09**	**0.92**	**73.6**
Offsite Motor Vehicle Exhaust	3.09	14.46	33.85	0.05	1.66	1.42	77.8
Offsite Motor Vehicle Fugitive PM	--	--	--	--	73.36	7.22	
Offsite Total	**3.09**	**14.46**	**33.85**	**0.05**	**75.02**	**8.65**	**77.8**
Total	**6.00**	**24.73**	**62.29**	**0.10**	**76.11**	**9.56**	**151.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
30-Ton Crane Truck	300	1	34	5
Backhoe/Front Loader	200	1	34	8
Auger Truck	500	1	34	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
30-Ton Crane Truck	300	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
Backhoe/Front Loader	200	0.126	0.375	1.281	0.002	0.042	0.038	171.737	0.011	Tractors/Loaders/Backhoes
Auger Truck	500	0.135	0.553	1.315	0.003	0.044	0.040	311.309	0.012	Bore/Drill Rigs

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
30-Ton Crane Truck	0.82	2.85	7.66	0.01	0.29	0.26
Backhoe/Front Loader	1.01	3.00	10.25	0.02	0.33	0.31
Auger Truck	1.08	4.42	10.52	0.02	0.35	0.32
Total	**2.91**	**10.27**	**28.44**	**0.05**	**0.97**	**0.89**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
30-Ton Crane Truck	13.9	0.0	13.9
Backhoe/Front Loader	21.2	0.0	21.2
Auger Truck	38.4	0.0	38.4
Total	**73.5**	**0.0**	**73.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				
Offsite				
Water Truck	1	34	N/A	14
1-Ton Crew Cab Flat Bed, 4x4	1	34	N/A	18
10-cu. yd. Dump Truck	8	34	N/A	64
10-cu. yd. Concrete Mixer Truck	8	34	N/A	64
30-Ton Crane Truck	1	34	N/A	18
Auger Truck	1	34	N/A	18
Worker Commute	7	34	N/A	60

[a] Concrete mixer and dump trucks based on 74.5 CY per foundation and 10 CY/truck = 74.5 / 10 = 7.5

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									

Table 28
Subtransmission Source Line Construction Emissions
Tubular Steel Pole Foundations Installation

Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
10-cu. yd. Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
10-cu. yd. Concrete Mixer Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
30-Ton Crane Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Auger Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Water Truck	0.04	0.14	0.43	0.00	0.02	0.02
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
10-cu. yd. Dump Truck	1.29	5.23	15.83	0.02	0.77	0.66
10-cu. yd. Concrete Mixer Truck	1.29	5.23	15.83	0.02	0.77	0.66
30-Ton Crane Truck	0.05	0.18	0.56	0.00	0.03	0.02
Auger Truck	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.33	3.21	0.33	0.00	0.04	0.02
Offsite Total	**3.09**	**14.46**	**33.85**	**0.05**	**1.66**	**1.42**
Total	**3.09**	**14.46**	**33.85**	**0.05**	**1.66**	**1.42**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Water Truck	0.9	0.0	0.9
1-Ton Crew Cab Flat Bed, 4x4	0.8	0.0	0.8
10-cu. yd. Dump Truck	33.3	0.0	33.3
10-cu. yd. Concrete Mixer Truck	33.3	0.0	33.3
30-Ton Crane Truck	1.2	0.0	1.2
Auger Truck	1.2	0.0	1.2
Worker Commute	7.1	0.0	7.1
Offsite Total	**77.7**	**0.0**	**77.8**
Total	**77.7**	**0.0**	**77.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None							
Onsite Total						**0.00**	**0.00**
Offsite							
Water Truck	1	Paved	10	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
10-cu. yd. Dump Truck	8	Paved	60	0.001	0.000	0.38	0.00
10-cu. yd. Concrete Mixer Truck	8	Paved	60	0.001	0.000	0.38	0.00
30-Ton Crane Truck	1	Paved	14	0.001	0.000	0.01	0.00
Auger Truck	1	Paved	14	0.001	0.000	0.01	0.00
Water Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
10-cu. yd. Dump Truck	8	Unpaved	4	0.922	0.092	29.51	2.95
10-cu. yd. Concrete Mixer Truck	8	Unpaved	4	0.922	0.092	29.51	2.95
30-Ton Crane Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Auger Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	7	Paved	60	0.001	0.000	0.34	0.00
Offsite Total						**73.36**	**7.22**
Total						**73.36**	**7.22**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Table 28
Subtransmission Source Line Construction Emissions
Tubular Steel Pole Foundations Installation

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	75	1.62E-03	3.36E-04	0.12	0.03
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.12**	**0.03**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on excavating 8 ft. diameter x 40 ft. deep per foundation and one foundation per day

Table 29
Subtransmission Source Line Construction Emissions
Wood Pole Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.19	7.31	19.55	0.02	0.84	0.77	20.3
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.02	0.00	
Onsite Total	**2.19**	**7.31**	**19.55**	**0.02**	**0.86**	**0.78**	**20.3**
Offsite Motor Vehicle Exhaust	0.46	4.23	1.00	0.01	0.07	0.05	5.4
Offsite Motor Vehicle Fugitive PM	--	--	--	--	4.27	0.39	
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**4.34**	**0.43**	**5.4**
Total	**2.65**	**11.54**	**20.55**	**0.03**	**5.20**	**1.21**	**25.7**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Compressor Trailer	120	1	19	5
80-Ton Rough Terrain Crane	350	1	19	6
Backhoe/Front Loader	200	1	19	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
80-Ton Rough Terrain Crane	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
Backhoe/Front Loader	200	0.126	0.375	1.281	0.002	0.042	0.038	171.737	0.011	Tractors/Loaders/Backhoes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Compressor Trailer	0.45	1.64	2.67	0.00	0.25	0.23
80-Ton Rough Terrain Crane	0.98	3.41	9.20	0.01	0.34	0.32
Backhoe/Front Loader	0.76	2.25	7.69	0.01	0.25	0.23
Total	**2.19**	**7.31**	**19.55**	**0.02**	**0.84**	**0.77**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Compressor Trailer	2.0	0.0	2.0
80-Ton Rough Terrain Crane	9.3	0.0	9.3
Backhoe/Front Loader	8.9	0.0	8.9
Total	**20.2**	**0.0**	**20.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	19	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	19	N/A	18
Worker Commute	8	19	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Table 29
Subtransmission Source Line Construction Emissions
Wood Pole Installation

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Worker Commute	0.38	3.67	0.37	0.01	0.04	0.03
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**
Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.4	0.0	0.4
1-Ton Crew Cab Flat Bed, 4x4	0.4	0.0	0.4
Worker Commute	4.6	0.0	4.6
Offsite Total	**5.4**	**0.0**	**5.4**
Total	**5.4**	**0.0**	**5.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Worker Commute	8	Paved	60	0.001	0.000	0.38	0.00
Offsite Total						**4.27**	**0.39**
Total						**4.27**	**0.39**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	12	1.62E-03	3.36E-04	0.02	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.02**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on excavating 3 ft. diameter x 11 ft. deep per pole x 4 poles per day

Table 30
Subtransmission Source Line Construction Emissions
Steel Pole Haul

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.98	3.41	9.20	0.01	0.34	0.32	2.5
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.98**	**3.41**	**9.20**	**0.01**	**0.34**	**0.32**	**2.5**
Offsite Motor Vehicle Exhaust	0.28	2.30	1.05	0.00	0.06	0.05	0.9
Offsite Motor Vehicle Fugitive PM	--	--	--	--	5.64	0.54	
Offsite Total	**0.28**	**2.30**	**1.05**	**0.00**	**5.70**	**0.59**	**0.9**
Total	**1.26**	**5.71**	**10.25**	**0.01**	**6.05**	**0.91**	**3.3**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
80-Ton Rough Terrain Crane	350	1	5	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
80-Ton Rough Terrain Crane	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
80-Ton Rough Terrain Crane	0.98	3.41	9.20	0.01	0.34	0.32
Total	**0.98**	**3.41**	**9.20**	**0.01**	**0.34**	**0.32**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
80-Ton Rough Terrain Crane	2.5	0.0	2.5
Total	**2.5**	**0.0**	**2.5**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	5	N/A	18
40' Flat Bed Truck/Trailer	1	5	N/A	18
Worker Commute	4	5	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None									
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
40' Flat Bed Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
40' Flat Bed Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.19	1.84	0.19	0.00	0.02	0.01

Table 30
Subtransmission Source Line Construction Emissions
Steel Pole Haul

Offsite Total	**0.28**	**2.30**	**1.05**	**0.00**	**0.06**	**0.05**
Total	**0.28**	**2.30**	**1.05**	**0.00**	**0.06**	**0.05**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.1	0.0	0.1
40' Flat Bed Truck/Trailer	0.2	0.0	0.2
Worker Commute	0.6	0.0	0.6
Offsite Total	**0.9**	**0.0**	**0.9**
Total	**0.9**	**0.0**	**0.9**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
40' Flat Bed Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
40' Flat Bed Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	4	Paved	60	0.001	0.000	0.19	0.00
Offsite Total						**5.64**	**0.54**
Total						**5.64**	**0.54**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 31
Subtransmission Source Line Construction Emissions
Steel Pole Assembly

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	1.43	5.06	11.86	0.01	0.59	0.54	3.6
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**1.43**	**5.06**	**11.86**	**0.01**	**0.59**	**0.54**	**3.6**
Offsite Motor Vehicle Exhaust	0.46	4.23	1.00	0.01	0.07	0.05	1.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	4.27	0.39	
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**4.34**	**0.43**	**1.7**
Total	**1.89**	**9.29**	**12.86**	**0.02**	**4.93**	**0.98**	**5.3**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Compressor Trailer	120	1	6	5
80-Ton Rough Terrain Crane	350	1	6	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
80-Ton Rough Terrain Crane	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Compressor Trailer	0.45	1.64	2.67	0.00	0.25	0.23
80-Ton Rough Terrain Crane	0.98	3.41	9.20	0.01	0.34	0.32
Total	**1.43**	**5.06**	**11.86**	**0.01**	**0.59**	**0.54**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Compressor Trailer	0.6	0.0	0.6
80-Ton Rough Terrain Crane	2.9	0.0	2.9
Total	**3.6**	**0.0**	**3.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	6	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	6	N/A	18
Worker Commute	8	6	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Table 31
Subtransmission Source Line Construction Emissions
Steel Pole Assembly

Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Worker Commute	0.38	3.67	0.37	0.01	0.04	0.03
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**
Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.1	0.0	0.1
1-Ton Crew Cab Flat Bed, 4x4	0.1	0.0	0.1
Worker Commute	1.4	0.0	1.4
Offsite Total	**1.7**	**0.0**	**1.7**
Total	**1.7**	**0.0**	**1.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Worker Commute	8	Paved	60	0.001	0.000	0.38	0.00
Offsite Total						**4.27**	**0.39**
Total						**4.27**	**0.39**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 32
Subtransmission Source Line Construction Emissions
Steel Pole Erection

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	1.43	5.06	11.86	0.01	0.59	0.54	3.6
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**1.43**	**5.06**	**11.86**	**0.01**	**0.59**	**0.54**	**3.6**
Offsite Motor Vehicle Exhaust	0.46	4.23	1.00	0.01	0.07	0.05	1.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	4.27	0.39	
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**4.34**	**0.43**	**1.7**
Total	**1.89**	**9.29**	**12.86**	**0.02**	**4.93**	**0.98**	**5.3**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Compressor Trailer	120	1	6	5
80-Ton Rough Terrain Crane	350	1	6	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
80-Ton Rough Terrain Crane	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Compressor Trailer	0.45	1.64	2.67	0.00	0.25	0.23
80-Ton Rough Terrain Crane	0.98	3.41	9.20	0.01	0.34	0.32
Total	**1.43**	**5.06**	**11.86**	**0.01**	**0.59**	**0.54**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Compressor Trailer	0.6	0.0	0.6
80-Ton Rough Terrain Crane	2.9	0.0	2.9
Total	**3.6**	**0.0**	**3.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	6	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	6	N/A	18
Worker Commute	8	6	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Table 32
Subtransmission Source Line Construction Emissions
Steel Pole Erection

Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Worker Commute	0.38	3.67	0.37	0.01	0.04	0.03
Offsite Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**
Total	**0.46**	**4.23**	**1.00**	**0.01**	**0.07**	**0.05**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.1	0.0	0.1
1-Ton Crew Cab Flat Bed, 4x4	0.1	0.0	0.1
Worker Commute	1.4	0.0	1.4
Offsite Total	**1.7**	**0.0**	**1.7**
Total	**1.7**	**0.0**	**1.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Worker Commute	8	Paved	60	0.001	0.000	0.38	0.00
Offsite Total						**4.27**	**0.39**
Total						**4.27**	**0.39**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 33
Subtransmission Source Line Construction Emissions
Conductor Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	4.23	15.33	45.87	0.06	1.53	1.41	28.4
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**4.23**	**15.33**	**45.87**	**0.06**	**1.53**	**1.41**	**28.4**
Offsite Motor Vehicle Exhaust	1.31	10.03	6.75	0.02	0.36	0.29	8.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	34.47	3.36	
Offsite Total	**1.31**	**10.03**	**6.75**	**0.02**	**34.83**	**3.65**	**8.7**
Total	**5.54**	**25.36**	**52.62**	**0.08**	**36.36**	**5.06**	**37.0**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Bucket Truck	350	1	10	8
22-Ton Manitex	350	1	10	8
Splicing Rig	10	1	10	2
Splicing Lab	16	1	10	2
3 Drum Straw Line Puller	300	1	10	6
Static Truck/Tensioner	350	1	10	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Bucket Truck	350	0.128	0.494	1.655	0.002	0.049	0.045	212.856	0.012	Aerial Lifts
22-Ton Manitex	350	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
Splicing Rig	10	0.012	0.062	0.074	0.000	0.003	0.003	10.107	0.001	Other Construction Equipment
Splicing Lab	16	0.028	0.095	0.163	0.000	0.010	0.009	17.631	0.002	Generator Sets
3 Drum Straw Line Puller	300	0.152	0.543	1.657	0.002	0.055	0.050	254.238	0.014	Other Construction Equipment
Static Truck/Tensioner	350	0.152	0.543	1.657	0.002	0.055	0.050	254.238	0.014	Other Construction Equipment

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Bucket Truck	1.02	3.95	13.24	0.02	0.39	0.36
22-Ton Manitex	1.31	4.55	12.26	0.01	0.46	0.42
Splicing Rig	0.02	0.12	0.15	0.00	0.01	0.01
Splicing Lab	0.06	0.19	0.33	0.00	0.02	0.02
3 Drum Straw Line Puller	0.91	3.26	9.94	0.01	0.33	0.30
Static Truck/Tensioner	0.91	3.26	9.94	0.01	0.33	0.30
Total	**4.23**	**15.33**	**45.87**	**0.06**	**1.53**	**1.41**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Bucket Truck	7.7	0.0	7.7
22-Ton Manitex	6.5	0.0	6.5
Splicing Rig	0.1	0.0	0.1
Splicing Lab	0.2	0.0	0.2
3 Drum Straw Line Puller	6.9	0.0	6.9
Static Truck/Tensioner	6.9	0.0	6.9
Total	**28.3**	**0.0**	**28.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	10	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	10	N/A	18
Wire Truck/Trailer	1	10	N/A	18

Table 33
Subtransmission Source Line Construction Emissions
Conductor Installation

Dump Truck (Trash)	1	10	N/A	64
Bucket Truck	1	10	N/A	18
22-Ton Manitex	1	10	N/A	18
Splicing Rig	1	10	N/A	18
Splicing Lab	1	10	N/A	18
3 Drum Straw Line Puller	1	10	N/A	18
Static Truck/Tensioner	1	10	N/A	18
Worker Commute	16	10	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Wire Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Dump Truck (Trash)	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Bucket Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
22-Ton Manitex	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Splicing Rig	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Splicing Lab	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
3 Drum Straw Line Puller	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Static Truck/Tensioner	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Wire Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
Dump Truck (Trash)	0.16	0.65	1.98	0.00	0.10	0.08
Bucket Truck	0.05	0.18	0.56	0.00	0.03	0.02
22-Ton Manitex	0.05	0.18	0.56	0.00	0.03	0.02
Splicing Rig	0.04	0.28	0.31	0.00	0.01	0.01
Splicing Lab	0.04	0.28	0.31	0.00	0.01	0.01
3 Drum Straw Line Puller	0.05	0.18	0.56	0.00	0.03	0.02
Static Truck/Tensioner	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.76	7.35	0.74	0.01	0.09	0.06
Offsite Total	**1.31**	**10.03**	**6.75**	**0.02**	**0.36**	**0.29**
Total	**1.31**	**10.03**	**6.75**	**0.02**	**0.36**	**0.29**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.2	0.0	0.2
1-Ton Crew Cab Flat Bed, 4x4	0.2	0.0	0.2
Wire Truck/Trailer	0.3	0.0	0.3
Dump Truck (Trash)	1.2	0.0	1.2
Bucket Truck	0.3	0.0	0.3
22-Ton Manitex	0.3	0.0	0.3
Splicing Rig	0.2	0.0	0.2
Splicing Lab	0.2	0.0	0.2
3 Drum Straw Line Puller	0.3	0.0	0.3
Static Truck/Tensioner	0.3	0.0	0.3
Worker Commute	4.8	0.0	4.8
Offsite Total	**8.6**	**0.0**	**8.7**
Total	**8.6**	**0.0**	**8.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Table 33
Subtransmission Source Line Construction Emissions
Conductor Installation

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Wire Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
Dump Truck (Trash)	1	Paved	60	0.001	0.000	0.05	0.00
Bucket Truck	1	Paved	14	0.001	0.000	0.01	0.00
22-Ton Manitex	1	Paved	14	0.001	0.000	0.01	0.00
Splicing Rig	1	Paved	14	0.001	0.000	0.01	0.00
Splicing Lab	1	Paved	14	0.001	0.000	0.01	0.00
3 Drum Straw Line Puller	1	Paved	14	0.001	0.000	0.01	0.00
Static Truck/Tensioner	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Wire Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
Dump Truck (Trash)	1	Unpaved	4	0.922	0.092	3.69	0.37
Bucket Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
22-Ton Manitex	1	Unpaved	4	0.922	0.092	3.69	0.37
Splicing Rig	1	Unpaved	4	0.726	0.073	2.91	0.29
Splicing Lab	1	Unpaved	4	0.726	0.073	2.91	0.29
3 Drum Straw Line Puller	1	Unpaved	4	0.922	0.092	3.69	0.37
Static Truck/Tensioner	1	Unpaved	4	0.922	0.092	3.69	0.37
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
Worker Commute	16	Paved	60	0.001	0.000	0.77	0.00
Offsite Total						**34.47**	**3.36**
Total						**34.47**	**3.36**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 34
Subtransmission Source Line Construction Emissions
Guard Structure Removal

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	3.11	10.75	29.77	0.04	1.20	1.10	3.3
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**3.11**	**10.75**	**29.77**	**0.04**	**1.20**	**1.10**	**3.3**
Offsite Motor Vehicle Exhaust	0.50	3.86	2.57	0.01	0.14	0.11	0.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	15.28	1.49	
Offsite Total	**0.50**	**3.86**	**2.57**	**0.01**	**15.41**	**1.60**	**0.7**
Total	**3.62**	**14.62**	**32.34**	**0.04**	**16.61**	**2.71**	**3.9**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Compressor Trailer	120	1	2	6
30-Ton Crane Truck	300	1	2	8
80ft. Hydraulic Manlift/Bucket Truck	350	1	2	4
Backhoe/Front Loader	200	1	2	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Compressor Trailer	120	0.089	0.329	0.533	0.001	0.049	0.045	46.950	0.008	Air Compressors
30-Ton Crane Truck	300	0.163	0.569	1.533	0.002	0.057	0.053	180.101	0.015	Cranes
80ft. Hydraulic Manlift/Bucket Truck	350	0.128	0.494	1.655	0.002	0.049	0.045	212.856	0.012	Aerial Lifts
Backhoe/Front Loader	200	0.126	0.375	1.281	0.002	0.042	0.038	171.737	0.011	Tractors/Loaders/Backhoes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Compressor Trailer	0.53	1.97	3.20	0.00	0.30	0.27
30-Ton Crane Truck	1.31	4.55	12.26	0.01	0.46	0.42
80ft. Hydraulic Manlift/Bucket Truck	0.51	1.98	6.62	0.01	0.20	0.18
Backhoe/Front Loader	0.76	2.25	7.69	0.01	0.25	0.23
Total	**3.11**	**10.75**	**29.77**	**0.04**	**1.20**	**1.10**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Compressor Trailer	0.3	0.0	0.3
30-Ton Crane Truck	1.3	0.0	1.3
80ft. Hydraulic Manlift/Bucket Truck	0.8	0.0	0.8
Backhoe/Front Loader	0.9	0.0	0.9
Total	**3.3**	**0.0**	**3.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
3/4-Ton Pick-up Truck, 4x4	1	2	N/A	18
1-Ton Crew Cab Flat Bed, 4x4	1	2	N/A	18
Extendable Flat Bed Pole Truck	1	2	N/A	18
30-Ton Crane Truck	1	2	N/A	18
80ft. Hydraulic Manlift/Bucket Truck	1	2	N/A	18
Worker Commute	6	2	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									

Table 34
Subtransmission Source Line Construction Emissions
Guard Structure Removal

None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
3/4-Ton Pick-up Truck, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
1-Ton Crew Cab Flat Bed, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Extendable Flat Bed Pole Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
30-Ton Crane Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
80ft. Hydraulic Manlift/Bucket Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
3/4-Ton Pick-up Truck, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
1-Ton Crew Cab Flat Bed, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Extendable Flat Bed Pole Truck	0.05	0.18	0.56	0.00	0.03	0.02
30-Ton Crane Truck	0.05	0.18	0.56	0.00	0.03	0.02
80ft. Hydraulic Manlift/Bucket Truck	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.50**	**3.86**	**2.57**	**0.01**	**0.14**	**0.11**
Total	**0.50**	**3.86**	**2.57**	**0.01**	**0.14**	**0.11**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
3/4-Ton Pick-up Truck, 4x4	0.0	0.0	0.0
1-Ton Crew Cab Flat Bed, 4x4	0.0	0.0	0.0
Extendable Flat Bed Pole Truck	0.1	0.0	0.1
30-Ton Crane Truck	0.1	0.0	0.1
80ft. Hydraulic Manlift/Bucket Truck	0.1	0.0	0.1
Worker Commute	0.4	0.0	0.4
Offsite Total	**0.7**	**0.0**	**0.7**
Total	**0.7**	**0.0**	**0.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0						
Onsite Total						**0.00**	**0.00**
Offsite							
3/4-Ton Pick-up Truck, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
1-Ton Crew Cab Flat Bed, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Extendable Flat Bed Pole Truck	1	Paved	14	0.001	0.000	0.01	0.00
30-Ton Crane Truck	1	Paved	14	0.001	0.000	0.01	0.00
80ft. Hydraulic Manlift/Bucket Truck	1	Paved	14	0.001	0.000	0.01	0.00
3/4-Ton Pick-up Truck, 4x4	1	Unpaved	4	0.435	0.043	1.74	0.17
1-Ton Crew Cab Flat Bed, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Extendable Flat Bed Pole Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
30-Ton Crane Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
80ft. Hydraulic Manlift/Bucket Truck	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**15.28**	**1.49**
Total						**15.28**	**1.49**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00

Table 34
Subtransmission Source Line Construction Emissions
Guard Structure Removal

Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 35
Subtransmission Source Line Construction Emissions
Restoration

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	5.00	17.19	47.30	0.06	1.74	1.60	10.8
Onsite Motor Vehicle Exhaust	0.01	0.03	0.09	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	2.77	0.28	
Earthwork Fugitive PM	--	--	--	--	17.77	3.70	
Onsite Total	**5.01**	**17.22**	**47.39**	**0.06**	**22.28**	**5.57**	**10.8**
Offsite Motor Vehicle Exhaust	0.45	3.81	1.60	0.01	0.10	0.07	1.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	8.95	0.86	
Offsite Total	**0.45**	**3.81**	**1.60**	**0.01**	**9.05**	**0.93**	**1.2**
Total	**5.46**	**21.03**	**48.99**	**0.07**	**31.32**	**6.51**	**11.9**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Road Grader	350	1	4	6
Backhoe/Front Loader	350	1	4	6
Drum Type Compactor	250	1	4	6
Track Type Dozer	350	1	4	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Road Grader	350	0.195	0.664	1.819	0.002	0.067	0.062	229.484	0.018	Graders
Backhoe/Front Loader	350	0.239	0.771	2.262	0.004	0.078	0.072	344.854	0.022	Tractors/Loaders/Backhoes
Drum Type Compactor	250	0.135	0.408	1.410	0.002	0.050	0.046	153.090	0.012	Rollers
Track Type Dozer	350	0.266	1.022	2.391	0.003	0.094	0.087	259.229	0.024	Crawler Tractors

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Road Grader	1.17	3.98	10.92	0.01	0.40	0.37
Backhoe/Front Loader	1.43	4.63	13.57	0.02	0.47	0.43
Drum Type Compactor	0.81	2.45	8.46	0.01	0.30	0.28
Track Type Dozer	1.60	6.13	14.35	0.02	0.57	0.52
Total	**5.00**	**17.19**	**47.30**	**0.06**	**1.74**	**1.60**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Road Grader	2.5	0.0	2.5
Backhoe/Front Loader	3.8	0.0	3.8
Drum Type Compactor	1.7	0.0	1.7
Track Type Dozer	2.8	0.0	2.8
Total	**10.7**	**0.0**	**10.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Water Truck	1	4	N/A	3
Offsite				
Water Truck	1	4	N/A	13
1-Ton Crew Cab, 4x4	1	4	N/A	18
Lowboy Truck/Trailer	1	4	N/A	18
Worker Commute	7	4	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
1-Ton Crew Cab, 4x4	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04

Table 35
Subtransmission Source Line Construction Emissions
Restoration

Lowboy Truck/Trailer	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Water Truck	0.01	0.03	0.09	0.00	0.00	0.00
Onsite Total	**0.01**	**0.03**	**0.09**	**0.00**	**0.00**	**0.00**
Offsite						
Water Truck	0.03	0.13	0.40	0.00	0.02	0.02
1-Ton Crew Cab, 4x4	0.04	0.28	0.31	0.00	0.01	0.01
Lowboy Truck/Trailer	0.05	0.18	0.56	0.00	0.03	0.02
Worker Commute	0.33	3.21	0.33	0.00	0.04	0.02
Offsite Total	**0.45**	**3.81**	**1.60**	**0.01**	**0.10**	**0.07**
Total	**0.46**	**3.84**	**1.69**	**0.01**	**0.10**	**0.08**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Water Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Water Truck	0.1	0.0	0.1
1-Ton Crew Cab, 4x4	0.1	0.0	0.1
Lowboy Truck/Trailer	0.1	0.0	0.1
Worker Commute	0.8	0.0	0.8
Offsite Total	**1.2**	**0.0**	**1.2**
Total	**1.2**	**0.0**	**1.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Water Truck	1	Unpaved	3	0.922	0.092	2.77	0.28
Onsite Total						**2.77**	**0.28**
Offsite							
Water Truck	1	Paved	10	0.001	0.000	0.01	0.00
1-Ton Crew Cab, 4x4	1	Paved	14	0.001	0.000	0.01	0.00
Lowboy Truck/Trailer	1	Paved	14	0.001	0.000	0.01	0.00
Water Truck	1	Unpaved	3	0.922	0.092	2.77	0.28
1-Ton Crew Cab, 4x4	1	Unpaved	4	0.532	0.053	2.13	0.21
Lowboy Truck/Trailer	1	Unpaved	4	0.922	0.092	3.69	0.37
Worker Commute	7	Paved	60	0.001	0.000	0.34	0.00
Offsite Total						**8.95**	**0.86**
Total						**11.72**	**1.13**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day	12	1.481	0.308	17.77	3.70
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**17.77**	**3.70**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 36
Telecomminications Construction
Control Building Communications Room

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.0**
Offsite Motor Vehicle Exhaust	0.24	2.27	0.45	0.00	0.03	0.02	1.4
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.23	0.00	
Offsite Total	**0.24**	**2.27**	**0.45**	**0.00**	**0.26**	**0.02**	**1.4**
Total	**0.24**	**2.27**	**0.45**	**0.00**	**0.26**	**0.02**	**1.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
Van	2	10	N/A	14
Crew Truck	1	1	N/A	14
Worker Commute	4	10	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Van	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Crew Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						

Table 36
Telecomminications Construction
Control Building Communications Room

Van	0.02	0.21	0.02	0.00	0.00	0.00
Crew Truck	0.03	0.22	0.24	0.00	0.01	0.01
Worker Commute	0.19	1.84	0.19	0.00	0.02	0.01
Offsite Total	**0.24**	**2.27**	**0.45**	**0.00**	**0.03**	**0.02**
Total	**0.24**	**2.27**	**0.45**	**0.00**	**0.03**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Van	0.1	0.0	0.1
Crew Truck	0.0	0.0	0.0
Worker Commute	1.2	0.0	1.2
Offsite Total	**1.4**	**0.0**	**1.4**
Total	**1.4**	**0.0**	**1.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0					0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Van	2	Paved	14	0.001	0.000	0.02	0.00
Crew Truck	1	Paved	14	0.001	0.000	0.01	0.00
Worker Commute	4	Paved	60	0.001	0.000	0.19	0.00
Offsite Total						**0.23**	**0.00**
Total						**0.23**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 37
Telecomminications Construction
Overhead Cable Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.26	8.67	27.79	0.04	0.86	0.79	70.9
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**2.26**	**8.67**	**27.79**	**0.04**	**0.86**	**0.79**	**70.9**
Offsite Motor Vehicle Exhaust	0.47	4.05	1.73	0.01	0.09	0.07	12.6
Offsite Motor Vehicle Fugitive PM	--	--	--	--	65.44	6.52	
Offsite Total	**0.47**	**4.05**	**1.73**	**0.01**	**65.53**	**6.58**	**12.6**
Total	**2.74**	**12.72**	**29.52**	**0.04**	**66.39**	**7.38**	**83.4**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Bucket Truck	350	2	44	8
Splice Lab Truck	16	1	44	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Bucket Truck	350	0.128	0.494	1.655	0.002	0.049	0.045	212.856	0.012	Aerial Lifts
Splice Lab Truck	16	0.028	0.095	0.163	0.000	0.010	0.009	17.631	0.002	Generator Sets

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Bucket Truck	2.04	7.90	26.48	0.03	0.79	0.72
Splice Lab Truck	0.22	0.76	1.31	0.00	0.08	0.07
Total	**2.26**	**8.67**	**27.79**	**0.04**	**0.86**	**0.79**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Bucket Truck	68.0	0.0	68.0
Splice Lab Truck	2.8	0.0	2.8
Total	**70.8**	**0.0**	**70.9**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
Bucket Truck	2	44	N/A	21
Splice Lab Truck	1	44	N/A	21
Crew Truck	1	44	N/A	21
Worker Commute	6	44	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Bucket Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Splice Lab Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Crew Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						

Table 37
Telecomminications Construction
Overhead Cable Installation

None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Bucket Truck	0.09	0.65	0.73	0.00	0.03	0.02
Splice Lab Truck	0.05	0.32	0.36	0.00	0.01	0.01
Crew Truck	0.05	0.32	0.36	0.00	0.01	0.01
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.47**	**4.05**	**1.73**	**0.01**	**0.09**	**0.07**
Total	**0.47**	**4.05**	**1.73**	**0.01**	**0.09**	**0.07**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Bucket Truck	2.3	0.0	2.3
Splice Lab Truck	1.2	0.0	1.2
Crew Truck	1.2	0.0	1.2
Worker Commute	7.9	0.0	7.9
Offsite Total	**12.6**	**0.0**	**12.6**
Total	**12.6**	**0.0**	**12.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0					0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Bucket Truck	2	Unpaved	21	0.922	0.092	38.73	3.87
Splice Lab Truck	1	Unpaved	21	0.726	0.073	15.25	1.53
Crew Truck	1	Unpaved	21	0.532	0.053	11.17	1.12
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**65.44**	**6.52**
Total						**65.44**	**6.52**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 38
Telecomminications Construction
Underground Facility Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.84	3.53	5.17	0.01	0.42	0.38	5.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.05	0.01	
Onsite Total	**0.84**	**3.53**	**5.17**	**0.01**	**0.47**	**0.40**	**5.0**
Offsite Motor Vehicle Exhaust	0.30	2.81	0.38	0.00	0.04	0.02	3.7
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.29	0.00	
Offsite Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.33**	**0.02**	**3.7**
Total	**1.14**	**6.33**	**5.54**	**0.01**	**0.80**	**0.42**	**8.8**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Backhoe	79	1	20	8
Concrete Mixer	120	1	20	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Backhoe	79	0.076	0.356	0.491	0.001	0.043	0.040	51.728	0.007	Tractors/Loaders/Backhoes
Concrete Mixer	25	0.029	0.085	0.155	0.000	0.009	0.008	17.556	0.003	Cement and Mortar Mixers

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Backhoe	0.61	2.85	3.93	0.00	0.35	0.32
Concrete Mixer	0.23	0.68	1.24	0.00	0.07	0.07
Total	**0.84**	**3.53**	**5.17**	**0.01**	**0.42**	**0.38**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Backhoe	3.8	0.0	3.8
Concrete Mixer	1.3	0.0	1.3
Total	**5.0**	**0.0**	**5.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
Crew Truck	2	20	N/A	1
Flatbed Truck	1	20	N/A	1
Stake Truck	1	20	N/A	1
Worker Commute	6	20	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Crew Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Flatbed Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Stake Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						

Table 38
Telecomminications Construction
Underground Facility Installation

None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.00	0.03	0.03	0.00	0.00	0.00
Flatbed Truck	0.00	0.01	0.03	0.00	0.00	0.00
Stake Truck	0.00	0.01	0.03	0.00	0.00	0.00
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.04**	**0.02**
Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.04**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crew Truck	0.1	0.0	0.1
Flatbed Truck	0.0	0.0	0.0
Stake Truck	0.0	0.0	0.0
Worker Commute	3.6	0.0	3.6
Offsite Total	**3.7**	**0.0**	**3.7**
Total	**3.7**	**0.0**	**3.7**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0					0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Crew Truck	2	Paved	1	0.001	0.000	0.00	0.00
Flatbed Truck	1	Paved	1	0.001	0.000	0.00	0.00
Stake Truck	1	Paved	1	0.001	0.000	0.00	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.29**	**0.00**
Total						**0.29**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling[c]	CY/day	34	1.62E-03	3.36E-04	0.05	0.01
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.05**	**0.01**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]
[c] Based on 671 CY over 20 days

Table 39
Telecomminications Construction
Underground Cable Installation

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	2.65	9.44	27.82	0.04	0.95	0.87	11.5
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**2.65**	**9.44**	**27.82**	**0.04**	**0.95**	**0.87**	**11.5**
Offsite Motor Vehicle Exhaust	0.30	2.81	0.38	0.00	0.04	0.02	1.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.29	0.00	
Offsite Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.33**	**0.02**	**1.1**
Total	**2.95**	**12.25**	**28.20**	**0.05**	**1.28**	**0.90**	**12.6**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Reel Truck	210	2	6	8
Splice Lab Truck	16	1	6	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Reel Truck	210	0.152	0.543	1.657	0.002	0.055	0.050	254.238	0.014	Other Construction Equipment
Splice Lab Truck	16	0.028	0.095	0.163	0.000	0.010	0.009	17.631	0.002	Generator Sets

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Reel Truck	2.43	8.68	26.52	0.04	0.87	0.80
Splice Lab Truck	0.22	0.76	1.31	0.00	0.08	0.07
Total	**2.65**	**9.44**	**27.82**	**0.04**	**0.95**	**0.87**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Reel Truck	11.1	0.0	11.1
Splice Lab Truck	0.4	0.0	0.4
Total	**11.5**	**0.0**	**11.5**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.[a]
Onsite				
None				0
Offsite				
Reel Truck	2	6	N/A	1
Crew Truck	1	6	N/A	1
Splice Lab Truck	1	6	N/A	1
Worker Commute	6	6	N/A	60

[a] Onsite travel based on 25% use at 10 mph average speed

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Reel Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Crew Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Splice Lab Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]

Table 39
Telecomminications Construction
Underground Cable Installation

Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Reel Truck	0.01	0.02	0.06	0.00	0.00	0.00
Crew Truck	0.00	0.02	0.02	0.00	0.00	0.00
Splice Lab Truck	0.00	0.02	0.02	0.00	0.00	0.00
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.04**	**0.02**
Total	**0.30**	**2.81**	**0.38**	**0.00**	**0.04**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Reel Truck	0.0	0.0	0.0
Crew Truck	0.0	0.0	0.0
Splice Lab Truck	0.0	0.0	0.0
Worker Commute	1.1	0.0	1.1
Offsite Total	**1.1**	**0.0**	**1.1**
Total	**1.1**	**0.0**	**1.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0					0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Reel Truck	2	Paved	1	0.001	0.000	0.00	0.00
Crew Truck	1	Paved	1	0.001	0.000	0.00	0.00
Splice Lab Truck	1	Paved	1	0.001	0.000	0.00	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.29**	**0.00**
Total						**0.29**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 40
Telecomminications Construction
Optical Systems Installation at Other Locations

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.0**
Offsite Motor Vehicle Exhaust	0.57	5.51	0.56	0.01	0.06	0.04	4.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.58	0.00	
Offsite Total	**0.57**	**5.51**	**0.56**	**0.01**	**0.64**	**0.04**	**4.3**
Total	**0.57**	**5.51**	**0.56**	**0.01**	**0.64**	**0.04**	**4.3**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
None				0
Offsite				
Van	6	12	N/A	60
Worker Commute	6	12	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
None		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Offsite									
Van	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
None	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Van	0.29	2.76	0.28	0.00	0.03	0.02
Worker Commute	0.29	2.76	0.28	0.00	0.03	0.02
Offsite Total	**0.57**	**5.51**	**0.56**	**0.01**	**0.06**	**0.04**
Total	**0.57**	**5.51**	**0.56**	**0.01**	**0.06**	**0.04**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Table 40
Telecomminications Construction
Optical Systems Installation at Other Locations

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
None	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Van	2.2	0.0	2.2
Worker Commute	2.2	0.0	2.2
Offsite Total	**4.3**	**0.0**	**4.3**
Total	**4.3**	**0.0**	**4.3**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
None	0					0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Van	6	Paved	60	0.001	0.000	0.29	0.00
Worker Commute	6	Paved	60	0.001	0.000	0.29	0.00
Offsite Total						**0.58**	**0.00**
Total						**0.58**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 41
Nuevo Substation Demolition Emissions
Civil

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.90	4.51	6.05	0.01	0.52	0.48	1.5
Onsite Motor Vehicle Exhaust	0.01	0.04	0.09	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.91**	**4.55**	**6.14**	**0.01**	**0.52**	**0.48**	**1.6**
Offsite Motor Vehicle Exhaust	0.57	3.62	4.25	0.01	0.22	0.19	2.0
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.24	0.00	
Offsite Total	**0.57**	**3.62**	**4.25**	**0.01**	**0.46**	**0.19**	**2.0**
Total	**1.47**	**8.17**	**10.40**	**0.02**	**0.99**	**0.67**	**3.5**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Backhoe	79	1	5	8
Bobcat Skid Steer	75	1	5	6

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Backhoe	79	0.076	0.356	0.491	0.001	0.043	0.040	51.728	0.007	Tractors/Loaders/Backhoes
Bobcat Skid Steer	75	0.048	0.277	0.354	0.001	0.029	0.026	42.762	0.004	Skid Steer Loaders

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Backhoe	0.61	2.85	3.93	0.00	0.35	0.32
Bobcat Skid Steer	0.29	1.66	2.12	0.00	0.17	0.16
Total	**0.90**	**4.51**	**6.05**	**0.01**	**0.52**	**0.48**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Backhoe	0.9	0.0	0.9
Bobcat Skid Steer	0.6	0.0	0.6
Total	**1.5**	**0.0**	**1.5**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Dump Truck	2	5	N/A	1
Water Truck	1	5	N/A	1
Tool Truck	1	5	N/A	1
Offsite				
Dump Truck	2	5	N/A	60
Water Truck	1	5	N/A	10
Worker Commute	5	5	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Tool Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Water Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Table 41
Nuevo Substation Demolition Emissions
Civil

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Dump Truck	0.01	0.02	0.06	0.00	0.00	0.00
Water Truck	0.00	0.01	0.03	0.00	0.00	0.00
Tool Truck	0.00	0.01	0.00	0.00	0.00	0.00
Onsite Total	**0.01**	**0.04**	**0.09**	**0.00**	**0.00**	**0.00**
Offsite						
Dump Truck	0.30	1.23	3.71	0.00	0.18	0.16
Water Truck	0.03	0.10	0.31	0.00	0.01	0.01
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.57**	**3.62**	**4.25**	**0.01**	**0.22**	**0.19**
Total	**0.58**	**3.66**	**4.35**	**0.01**	**0.23**	**0.19**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Dump Truck	0.0	0.0	0.0
Water Truck	0.0	0.0	0.0
Tool Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Dump Truck	1.1	0.0	1.1
Water Truck	0.1	0.0	0.1
Worker Commute	0.7	0.0	0.8
Offsite Total	**2.0**	**0.0**	**2.0**
Total	**2.0**	**0.0**	**2.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Dump Truck	2	Paved	1	0.001	0.000	0.00	0.00
Water Truck	1	Paved	1	0.001	0.000	0.00	0.00
Tool Truck	1	Paved	1	0.001	0.000	0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Dump Truck	2	Paved	60	0.001	0.000	0.10	0.00
Water Truck	1	Paved	10	0.001	0.000	0.01	0.00
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**0.24**	**0.00**
Total						**0.24**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 42
Nuevo Substation Demolition Emissions
Electrical

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.54	28.46	4.03	0.00	0.27	0.25	1.6
Onsite Motor Vehicle Exhaust	0.00	0.02	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.54**	**28.48**	**4.04**	**0.00**	**0.27**	**0.25**	**1.6**
Offsite Motor Vehicle Exhaust	0.26	2.48	0.25	0.00	0.03	0.02	1.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.26	0.00	
Offsite Total	**0.26**	**2.48**	**0.25**	**0.00**	**0.29**	**0.02**	**1.1**
Total	**0.80**	**30.96**	**4.29**	**0.01**	**0.56**	**0.27**	**2.7**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Manlift	25	2	7	6
15-Ton Crane	125	1	7	4

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Manlift	25	0.008	2.210	0.061	0.000	0.007	0.006	13.000	0.070	Aerial Lifts-Propane
15-Ton Crane	125	0.109	0.484	0.826	0.001	0.048	0.044	80.345	0.010	Cranes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Manlift	0.10	26.53	0.73	0.00	0.08	0.07
15-Ton Crane	0.44	1.94	3.30	0.00	0.19	0.18
Total	**0.54**	**28.46**	**4.03**	**0.00**	**0.27**	**0.25**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Manlift	0.5	0.0	0.6
15-Ton Crane	1.0	0.0	1.0
Total	**1.5**	**0.0**	**1.6**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Tool Trailer	1	7	N/A	1
Crew Truck	2	7	N/A	1
Offsite				
Crew Truck	2	7	N/A	12
Worker Commute	5	7	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Tool Trailer	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]

Table 42
Nuevo Substation Demolition Emissions
Electrical

Onsite						
Tool Trailer	0.00	0.01	0.00	0.00	0.00	0.00
Crew Truck	0.00	0.02	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.02**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.02	0.18	0.02	0.00	0.00	0.00
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.26**	**2.48**	**0.25**	**0.00**	**0.03**	**0.02**
Total	**0.26**	**2.50**	**0.25**	**0.00**	**0.03**	**0.02**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Tool Trailer	0.0	0.0	0.0
Crew Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crew Truck	0.1	0.0	0.1
Worker Commute	1.0	0.0	1.1
Offsite Total	**1.1**	**0.0**	**1.1**
Total	**1.1**	**0.0**	**1.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Tool Trailer	1	Paved	1	0.001	0.000	0.00	0.00
Crew Truck	2	Paved	1	0.001	0.000	0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Crew Truck	2	Paved	12	0.001	0.000	0.02	0.00
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**0.26**	**0.00**
Total						**0.26**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 43
Nuevo Substation Demolition Emissions
Maintenance Crew Equipment Check

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.0**
Offsite Motor Vehicle Exhaust	0.11	1.01	0.10	0.00	0.01	0.01	0.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.11	0.00	
Offsite Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.12**	**0.01**	**0.1**
Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.12**	**0.01**	**0.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None										

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Maintenance Truck	1	2	N/A	0.5
Offsite				
Maintenance Truck	1	2	N/A	12
Worker Commute	2	2	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Maintenance Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Maintenance Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Maintenance Truck	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Maintenance Truck	0.01	0.09	0.01	0.00	0.00	0.00
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01

Table 43
Nuevo Substation Demolition Emissions
Maintenance Crew Equipment Check

Offsite Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.01**	**0.01**
Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Maintenance Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Maintenance Truck	0.0	0.0	0.0
Worker Commute	0.1	0.0	0.1
Offsite Total	**0.1**	**0.0**	**0.1**
Total	**0.1**	**0.0**	**0.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Maintenance Truck	1	Paved	0.5	0.001	0.000	0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Maintenance Truck	1	Paved	12	0.001	0.000	0.01	0.00
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**0.11**	**0.00**
Total						**0.11**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 44
Nuevo Substation Demolition Emissions
Testing

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Exhaust	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.27	0.03	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.27**	**0.03**	**0.0**
Offsite Motor Vehicle Exhaust	0.11	1.01	0.10	0.00	0.01	0.01	0.1
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.11	0.00	
Offsite Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.12**	**0.01**	**0.1**
Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.38**	**0.03**	**0.1**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
None				

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
None										

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
None	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
None	0.0	0.0	0.0
Total	**0.0**	**0.0**	**0.0**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Crew Truck	1	2	N/A	0.5
Offsite				
Crew Truck	1	2	N/A	12
Worker Commute	2	2	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Crew Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Crew Truck	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Offsite						
Crew Truck	0.01	0.09	0.01	0.00	0.00	0.00
Worker Commute	0.10	0.92	0.09	0.00	0.01	0.01

Table 44
Nuevo Substation Demolition Emissions
Testing

Offsite Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.01**	**0.01**
Total	**0.11**	**1.01**	**0.10**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Crew Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Crew Truck	0.0	0.0	0.0
Worker Commute	0.1	0.0	0.1
Offsite Total	**0.1**	**0.0**	**0.1**
Total	**0.1**	**0.0**	**0.1**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Crew Truck	1	Unpaved	0.5	0.532	0.053	0.27	0.03
Onsite Total						**0.27**	**0.03**
Offsite							
Crew Truck	1	Paved	12	0.001	0.000	0.01	0.00
Worker Commute	2	Paved	60	0.001	0.000	0.10	0.00
Offsite Total						**0.11**	**0.00**
Total						**0.37**	**0.03**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 45
Model P.T. Substation Demolition Emissions
Civil

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	0.61	2.85	3.93	0.00	0.35	0.32	0.8
Onsite Motor Vehicle Exhaust	0.01	0.03	0.06	0.00	0.00	0.00	0.0
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**0.61**	**2.87**	**3.99**	**0.00**	**0.35**	**0.32**	**0.8**
Offsite Motor Vehicle Exhaust	0.43	3.12	2.47	0.01	0.14	0.11	1.2
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.24	0.00	
Offsite Total	**0.43**	**3.12**	**2.47**	**0.01**	**0.38**	**0.11**	**1.2**
Total	**1.04**	**6.00**	**6.46**	**0.01**	**0.73**	**0.43**	**1.9**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Backhoe	79	1	4	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Backhoe	79	0.076	0.356	0.491	0.001	0.043	0.040	51.728	0.007	Tractors/Loaders/Backhoes

a From Table 48

[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction= 0.920

From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Backhoe	0.61	2.85	3.93	0.00	0.35	0.32
Total	**0.61**	**2.85**	**3.93**	**0.00**	**0.35**	**0.32**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Backhoe	0.8	0.0	0.8
Total	**0.8**	**0.0**	**0.8**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number[a]	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Dump Truck	1	4	N/A	1
Flatbed Truck	1	4	N/A	1
Foreman Truck	1	4	N/A	1
Offsite				
Dump Truck	1	4	N/A	60
Flatbed Truck	1	4	N/A	12
Foreman Truck	1	4	N/A	12
Worker Commute	5	4	N/A	60

[a] Concrete trucks based on 430 CY over 5 days and 10 CY/truck = 430 / 5 / 10 = 8.6

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Flatbed Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Foreman Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Offsite									
Dump Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Flatbed Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Foreman Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Table 45
Model P.T. Substation Demolition Emissions
Civil

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Dump Truck	0.00	0.01	0.03	0.00	0.00	0.00
Flatbed Truck	0.00	0.01	0.03	0.00	0.00	0.00
Foreman Truck	0.00	0.01	0.00	0.00	0.00	0.00
Onsite Total	**0.01**	**0.03**	**0.06**	**0.00**	**0.00**	**0.00**
Offsite						
Dump Truck	0.15	0.61	1.86	0.00	0.09	0.08
Flatbed Truck	0.03	0.12	0.37	0.00	0.02	0.02
Foreman Truck	0.01	0.09	0.01	0.00	0.00	0.00
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.43**	**3.12**	**2.47**	**0.01**	**0.14**	**0.11**
Total	**0.44**	**3.15**	**2.53**	**0.01**	**0.14**	**0.11**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Dump Truck	0.0	0.0	0.0
Flatbed Truck	0.0	0.0	0.0
Foreman Truck	0.0	0.0	0.0
Onsite Total	**0.0**	**0.0**	**0.0**
Offsite			
Dump Truck	0.5	0.0	0.5
Flatbed Truck	0.1	0.0	0.1
Foreman Truck	0.0	0.0	0.0
Worker Commute	0.6	0.0	0.6
Offsite Total	**1.2**	**0.0**	**1.2**
Total	**1.2**	**0.0**	**1.2**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Dump Truck	1	Paved	1	0.001	0.000	0.00	0.00
Flatbed Truck	1	Paved	1	0.001	0.000	0.00	0.00
Foreman Truck	1	Paved	1	0.001	0.000	0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Dump Truck	1	Paved	60	0.001	0.000	0.05	0.00
Flatbed Truck	1	Paved	12	0.001	0.000	0.01	0.00
Foreman Truck	1	Paved	12	0.001	0.000	0.01	0.00
Worker Commute	5	Paved	60	0.001	0.000	0.24	0.00
Offsite Total						**0.24**	**0.00**
Total						**0.24**	**0.00**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 46
Model P.T. Substation Demolition Emissions
Electrical

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT)
Construction Equipment Exhaust	3.06	11.19	29.03	0.04	1.15	1.06	36.5
Onsite Motor Vehicle Exhaust	0.01	0.03	0.06	0.00	0.00	0.00	0.1
Onsite Motor Vehicle Fugitive PM	--	--	--	--	0.00	0.00	
Earthwork Fugitive PM	--	--	--	--	0.00	0.00	
Onsite Total	**3.07**	**11.22**	**29.09**	**0.04**	**1.16**	**1.07**	**36.6**
Offsite Motor Vehicle Exhaust	0.40	3.41	1.48	0.01	0.07	0.06	5.3
Offsite Motor Vehicle Fugitive PM	--	--	--	--	0.30	0.30	
Offsite Total	**0.40**	**3.41**	**1.48**	**0.01**	**0.37**	**0.35**	**5.3**
Total	**3.47**	**14.63**	**30.57**	**0.04**	**1.53**	**1.42**	**41.9**

Construction Equipment Summary

Equipment	Horse-power	Number	Days Used	Hours Used/ Day
Wire Dolly	9	1	22	8
Boom Truck	235	1	22	8
Pumper/Tanker Truck	200	1	22	8
Crane	125	1	22	8

Construction Equipment Exhaust Emission Factors

Equipment	Horse-power	VOC (lb/hr)[a]	CO (lb/hr)[a]	NOX (lb/hr)[a]	SOX (lb/hr)[a]	PM10 (lb/hr)[a]	PM2.5 (lb/hr)[b]	CO2 (lb/hr)[a]	CH4 (lb/hr)[a]	Category
Wire Dolly	9	0.012	0.062	0.074	0.000	0.003	0.003	10.107	0.001	Other Construction Equipment
Boom Truck	235	0.110	0.310	1.071	0.001	0.039	0.036	112.159	0.010	Cranes
Pumper/Tanker Truck	200	0.152	0.543	1.657	0.002	0.055	0.050	254.238	0.014	Other Construction Equipment
Crane	125	0.109	0.484	0.826	0.001	0.048	0.044	80.345	0.010	Cranes

a From Table 48
[b] Diesel PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10
PM2.5 Fraction= 0.920
From Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5
and PM 2.5 Significance Thresholds, SCAQMD, October 2006,
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html

Construction Equipment Daily Criteria Pollutant Exhaust Emissions

Equipment	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Wire Dolly	0.09	0.49	0.59	0.00	0.02	0.02
Boom Truck	0.88	2.48	8.57	0.01	0.31	0.29
Pumper/Tanker Truck	1.21	4.34	13.26	0.02	0.44	0.40
Crane	0.87	3.87	6.61	0.01	0.38	0.35
Total	**3.06**	**11.19**	**29.03**	**0.04**	**1.15**	**1.06**

[a] Emissions [lb/day] = number x hours/day x emission factor [lb/hr]

Construction Equipment Total Greenhouse Gas Emissions

Equipment	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Wire Dolly	0.8	0.0	0.8
Boom Truck	9.0	0.0	9.0
Pumper/Tanker Truck	20.3	0.0	20.3
Crane	6.4	0.0	6.4
Total	**36.5**	**0.0**	**36.5**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x hours/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 48
[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Usage

Vehicle	Number	Days Used	Hours Used/ Day	Miles/ Day/ Veh.
Onsite				
Line Truck	1	22	N/A	0.5
Troubleman Truck	1	22	N/A	0.5
Boom Truck	1	22	N/A	0.5
Foreman Truck	1	22	N/A	0.5
Flatbed Truck	1	22	N/A	0.5
Pumper/Tanker Truck	1	22	N/A	0.5
Offsite				
Line Truck	1	22	N/A	12
Troubleman Truck	1	22	N/A	12

Table 46
Model P.T. Substation Demolition Emissions
Electrical

Boom Truck	1	22	N/A	12
Foreman Truck	1	22	N/A	12
Flatbed Truck	1	22	N/A	12
Pumper/Tanker Truck	1	22	N/A	12
Worker Commute	5	22	N/A	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Onsite									
Line Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Troubleman Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Boom Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Foreman Truck	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Flatbed Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Pumper/Tanker Truck	HHDT	2.53E-03	1.02E-02	3.09E-02	4.04E-05	1.50E-03	1.29E-03	4.22E+00	1.17E-04
Offsite									
Line Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Troubleman Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Boom Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Foreman Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Flatbed Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Pumper/Tanker Truck	Delivery	2.24E-03	1.55E-02	1.73E-02	2.67E-05	6.50E-04	5.50E-04	2.77E+00	1.07E-04
Worker Commute	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Onsite						
Line Truck	0.00	0.01	0.01	0.00	0.00	0.00
Troubleman Truck	0.00	0.01	0.01	0.00	0.00	0.00
Boom Truck	0.00	0.01	0.02	0.00	0.00	0.00
Foreman Truck	0.00	0.00	0.00	0.00	0.00	0.00
Flatbed Truck	0.00	0.01	0.02	0.00	0.00	0.00
Pumper/Tanker Truck	0.00	0.01	0.02	0.00	0.00	0.00
Onsite Total	**0.01**	**0.03**	**0.06**	**0.00**	**0.00**	**0.00**
Offsite						
Line Truck	0.03	0.19	0.21	0.00	0.01	0.01
Troubleman Truck	0.03	0.19	0.21	0.00	0.01	0.01
Boom Truck	0.03	0.19	0.21	0.00	0.01	0.01
Foreman Truck	0.03	0.19	0.21	0.00	0.01	0.01
Flatbed Truck	0.03	0.19	0.21	0.00	0.01	0.01
Pumper/Tanker Truck	0.03	0.19	0.21	0.00	0.01	0.01
Worker Commute	0.24	2.30	0.23	0.00	0.03	0.02
Offsite Total	**0.40**	**3.41**	**1.48**	**0.01**	**0.07**	**0.06**
Total	**0.41**	**3.44**	**1.54**	**0.01**	**0.08**	**0.06**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Total Greenhouse Gas Emissions

Vehicle	CO2 (MT)[a]	CH4 (MT)[a]	CO2e (MT)[b]
Onsite			
Line Truck	0.0	0.0	0.0
Troubleman Truck	0.0	0.0	0.0
Boom Truck	0.0	0.0	0.0
Foreman Truck	0.0	0.0	0.0
Flatbed Truck	0.0	0.0	0.0
Pumper/Tanker Truck	0.0	0.0	0.0
Onsite Total	**0.1**	**0.0**	**0.1**
Offsite			
Line Truck	0.3	0.0	0.3
Troubleman Truck	0.3	0.0	0.3
Boom Truck	0.3	0.0	0.3
Foreman Truck	0.3	0.0	0.3
Flatbed Truck	0.3	0.0	0.3
Pumper/Tanker Truck	0.3	0.0	0.3
Worker Commute	3.3	0.0	3.3
Offsite Total	**5.3**	**0.0**	**5.3**
Total	**5.4**	**0.0**	**5.4**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x
days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action
Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Table 46
Model P.T. Substation Demolition Emissions
Electrical

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Onsite							
Line Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Troubleman Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Boom Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Foreman Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Flatbed Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Pumper/Tanker Truck	1	Paved	0.5	0.001	0.001	0.00	0.00
Onsite Total						**0.00**	**0.00**
Offsite							
Line Truck	1	Paved	12	0.001	0.001	0.01	0.01
Troubleman Truck	1	Paved	12	0.001	0.001	0.01	0.01
Boom Truck	1	Paved	12	0.001	0.001	0.01	0.01
Foreman Truck	1	Paved	12	0.001	0.001	0.01	0.01
Flatbed Truck	1	Paved	12	0.001	0.001	0.01	0.01
Pumper/Tanker Truck	1	Paved	12	0.001	0.001	0.01	0.01
Worker Commute	5	Paved	60	0.001	0.001	0.24	0.24
Offsite Total						**0.30**	**0.30**
Total						**0.30**	**0.30**

a From Table 51
[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Earthwork Fugitive Particulate Matter Emissions

Activity	Activity Units	Activity Level	PM10 Emission Factor[a]	PM2.5 Emission Factor[a]	PM10 (lb/day)[b]	PM2.5 (lb/day)[b]
Soil Handling	CY/day		1.62E-03	3.36E-04	0.00	0.00
Bulldozing, Scraping and Grading	hr/day		1.481	0.308	0.00	0.00
Storage Pile Wind Erosion	acres		15.7	3.26	0.00	0.00
Total					**0.00**	**0.00**

a From Table 52
[b] Emissions [lb/day] = Emission factor [lb/activity unit] x Activity unit [units/day]

Table 47
Operational Emissions

Emissions Summary

Source	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2e (MT/yr)
Motor Vehicle Exhaust	0.10	0.97	0.10	0.00	0.01	0.01	1
Motor Vehicle Fugitive PM	--	--	--	--	3.15	0.30	--
SF6 Leakage	--	--	--	--	--	--	20
Total	**0.10**	**0.97**	**0.10**	**0.00**	**3.16**	**0.31**	**21**

Motor Vehicle Usage

Vehicle	Number	Days Used/ Year	Miles/ Day/ Veh.
Subtransmission Line Inspection	1	1	67
Substation Site Visit	1	48	60

Motor Vehicle Exhaust Emission Factors

Vehicle	Category	VOC (lb/mi)[a]	CO (lb/mi)[a]	NOX (lb/mi)[a]	SOX (lb/mi)[a]	PM10 (lb/mi)[a]	PM2.5 (lb/mi)[b]	CO2 (lb/mi)[a]	CH4 (lb/mi)[a]
Subtransmission Line Inspection	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05
Substation Site Visit	Passenger	7.96E-04	7.65E-03	7.76E-04	1.07E-05	8.98E-05	5.75E-05	1.10E+00	7.17E-05

a From Table 49 or Table 50

Motor Vehicle Daily Criteria Pollutant Exhaust Emissions

Vehicle	VOC (lb/day)[a]	CO (lb/day)[a]	NOX (lb/day)[a]	SOX (lb/day)[a]	PM10 (lb/day)[a]	PM2.5 (lb/day)[a]
Subtransmission Line Inspection	0.05	0.51	0.05	0.00	0.01	0.00
Substation Site Visit	0.05	0.46	0.05	0.00	0.01	0.00
Total	**0.10**	**0.97**	**0.10**	**0.00**	**0.01**	**0.01**

[a] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

Motor Vehicle Annual Greenhouse Gas Emissions

Vehicle	CO2 (MT/yr)[a]	CH4 (MT/yr)[a]	CO2e (MT/yr)[b]
Subtransmission Line Inspection	0.0	0.0	0.0
Substation Site Visit	1.4	0.0	1.4
Total	**1.5**	**0.0**	**1.5**

[a] Emissions [metric tons, MT] = emission factor [lb/hr] x miles/day x Number x days used x 453.6 [g/lb] / 1,000,000 [g/MT]
Emission factors are in Table 49 and Table 50

[b] CO_2-equivalent (CO_2e) emission factors are CO_2 emissions plus 21 x CH_4 emissions, based on Table C.1 from California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008, http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

Motor Vehicle Fugitive Particulate Matter Emissions

Vehicle	Number	Road Type	Miles/ Day/ Vehicle	PM10 Emission Factor (lb/mi)[a]	PM2.5 Emission Factor (lb/mi)[a]	PM10 Emissions (lb/day)[b]	PM2.5 Emissions (lb/day)[b]
Subtransmission Line Inspection	1	Paved	67	0.001	0.000	0.05	0.00
Subtransmission Line Inspection	1	Unpaved	7	0.435	0.043	3.04	0.30
Substation Site Visit	1	Paved	60	0.001	0.000	0.05	0.00
Total						**3.15**	**0.30**

a From Table 51

[b] Emissions [lb/day] = number x miles/day x emission factor [lb/mi]

SF6 Leakage Greenhouse Gas Emissions

Item	Value	Units
Total SF6	378	pounds
SF6 Leakage Rate	0.5	%/year
SF6 Emissions	1.89	pounds
SF6 Global Warming Potential[a]	23,200	
CO2e Emissions[b]	**20**	**MT/yr**

[a] Based on Table C.1 from California Climate Action

Table 47
Operational Emissions

Registry General Reporting Protocol, Version 3.0,
April 2008.
http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf

[b] CO_2e emissions [metric tons] = SF_6 emissions [lb] x Global warming potential [lb CO_2e/lb SF_6] x 453.6 [g/lb] / 1,000,000 [g/MT]

Table 48

SCAB Fleet Average Emission Factors (Diesel)

2012

Air Basin	SC

		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Equipment	**MaxHP**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**CO2**	**CH4**
Aerial Lifts	15	0.0102	0.0528	0.0642	0.0001	0.0030	8.7	0.0009
	25	0.0175	0.0517	0.0957	0.0001	0.0055	11.0	0.0016
	50	0.0650	0.1822	0.1916	0.0003	0.0169	19.6	0.0059
	120	0.0607	0.2451	0.4012	0.0004	0.0324	38.1	0.0055
	500	0.1276	0.4941	1.6553	0.0021	0.0491	213	0.0115
	750	0.2379	0.8930	3.0795	0.0039	0.0903	385	0.0215
Aerial Lifts Composite		0.0576	0.1976	0.3249	0.0004	0.0219	34.7	0.0052
Aerial Lifts-Propane	15	0.0037	1.4362	0.0393	0.0000	0.0041	8.9	0.0311
	25	0.0083	2.2104	0.0608	0.0000	0.0067	13.0	0.0697
Aerial Lifts-Propane Composite								
Air Compressors	15	0.0129	0.0494	0.0768	0.0001	0.0052	7.2	0.0012
	25	0.0286	0.0779	0.1337	0.0002	0.0087	14.4	0.0026
	50	0.1010	0.2646	0.2310	0.0003	0.0239	22.3	0.0091
	120	0.0891	0.3287	0.5333	0.0006	0.0492	47.0	0.0080
	175	0.1135	0.5074	0.8954	0.0010	0.0512	88.5	0.0102
	250	0.1066	0.3052	1.2194	0.0015	0.0379	131	0.0096
	500	0.1709	0.5726	1.9077	0.0023	0.0623	232	0.0154
	750	0.2681	0.8849	3.0371	0.0036	0.0980	358	0.0242
	1000	0.4533	1.5617	5.4098	0.0049	0.1589	486	0.0409
Air Compressors Composite		0.0984	0.3445	0.6494	0.0007	0.0469	63.6	0.0089
Bore/Drill Rigs	15	0.0120	0.0632	0.0754	0.0002	0.0029	10.3	0.0011
	25	0.0194	0.0658	0.1233	0.0002	0.0054	16.0	0.0017
	50	0.0351	0.2335	0.2768	0.0004	0.0149	31.0	0.0032
	120	0.0514	0.4724	0.5026	0.0009	0.0328	77.1	0.0046
	175	0.0750	0.7538	0.7479	0.0016	0.0366	141	0.0068
	250	0.0838	0.3435	0.8722	0.0021	0.0268	188	0.0076
	500	0.1354	0.5526	1.3152	0.0031	0.0437	311	0.0122
	750	0.2685	1.0916	2.6320	0.0062	0.0865	615	0.0242
	1000	0.4491	1.6773	6.6123	0.0093	0.1699	928	0.0405
Bore/Drill Rigs Composite		0.0854	0.5068	0.9013	0.0017	0.0367	165	0.0077
Cement and Mortar Mixers	15	0.0075	0.0386	0.0475	0.0001	0.0023	6.3	0.0007
	25	0.0293	0.0852	0.1548	0.0002	0.0091	17.6	0.0026
Cement and Mortar Mixers Composite		0.0093	0.0425	0.0564	0.0001	0.0029	7.2	0.0008
Concrete/Industrial Saws	25	0.0199	0.0678	0.1261	0.0002	0.0050	16.5	0.0018
	50	0.1047	0.3015	0.2972	0.0004	0.0268	30.2	0.0094
	120	0.1155	0.4880	0.7625	0.0009	0.0639	74.1	0.0104
	175	0.1685	0.8723	1.4507	0.0018	0.0767	160	0.0152
Concrete/Industrial Saws Composite		0.1090	0.4148	0.5910	0.0007	0.0491	58.5	0.0098
Cranes	50	0.1101	0.2979	0.2478	0.0003	0.0258	23.2	0.0099
	120	0.0982	0.3650	0.5844	0.0006	0.0533	50.1	50.1
	175	0.1089	0.4838	0.8259	0.0009	0.0479	80.3	0.0098
	250	0.1103	0.3103	1.0712	0.0013	0.0388	112	0.0100
	500	0.1635	0.5691	1.5327	0.0018	0.0571	180	0.0148
	750	0.2767	0.9554	2.6486	0.0030	0.0974	303	0.0250
	9999	0.9905	3.5715	10.9484	0.0098	0.3384	971	0.0894
Cranes Composite		0.1425	0.4946	1.2753	0.0014	0.0553	129	0.0129
Crawler Tractors	50	0.1262	0.3333	0.2713	0.0003	0.0289	24.9	0.0114
	120	0.1374	0.4906	0.8120	0.0008	0.0729	65.8	0.0124
	175	0.1758	0.7491	1.3245	0.0014	0.0765	121	0.0159
	250	0.1854	0.5225	1.7044	0.0019	0.0667	166	0.0167
	500	0.2659	1.0217	2.3914	0.0025	0.0942	259	0.0240
	750	0.4784	1.8248	4.3817	0.0047	0.1705	465	0.0432
	1000	0.7229	2.8959	7.7626	0.0066	0.2503	658	0.0652
Crawler Tractors Composite		0.1671	0.6051	1.2309	0.0013	0.0752	114	0.0151
Crushing/Proc. Equipment	50	0.1927	0.5215	0.4545	0.0006	0.0462	44.0	0.0174

Table 48

SCAB Fleet Average Emission Factors (Diesel)

2012

Air Basin	SC

		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Equipment	**MaxHP**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**CO2**	**CH4**
	120	0.1525	0.5829	0.9172	0.0010	0.0851	83.1	0.0138
	175	0.2088	0.9654	1.6343	0.0019	0.0946	167	0.0188
	250	0.1953	0.5592	2.1896	0.0028	0.0682	245	0.0176
	500	0.2733	0.8961	2.9457	0.0037	0.0972	374	0.0247
	750	0.4361	1.3892	4.8387	0.0059	0.1560	589	0.0394
	9999	1.2112	4.0327	14.2648	0.0131	0.4203	1,308	0.1093
Crushing/Proc. Equipment Composite		0.1872	0.6911	1.2633	0.0015	0.0819	132	0.0169
Dumpers/Tenders	25	0.0100	0.0324	0.0614	0.0001	0.0031	7.6	0.0009
Dumpers/Tenders Composite		0.0100	0.0324	0.0614	0.0001	0.0031	7.6	0.0009
Excavators	25	0.0198	0.0677	0.1253	0.0002	0.0048	16.4	0.0018
	50	0.0912	0.2933	0.2568	0.0003	0.0237	25.0	0.0082
	120	0.1183	0.5220	0.7300	0.0009	0.0657	73.6	0.0107
	175	0.1288	0.6678	0.9613	0.0013	0.0569	112	0.0116
	250	0.1301	0.3630	1.2438	0.0018	0.0415	159	0.0117
	500	0.1805	0.5493	1.6112	0.0023	0.0574	234	0.0163
	750	0.3013	0.9096	2.7605	0.0039	0.0969	387	0.0272
Excavators Composite		0.1300	0.5401	0.9817	0.0013	0.0536	120	0.0117
Forklifts	50	0.0514	0.1682	0.1488	0.0002	0.0136	14.7	0.0046
	120	0.0489	0.2195	0.3017	0.0004	0.0277	31.2	0.0044
	175	0.0624	0.3304	0.4664	0.0006	0.0278	56.1	0.0056
	250	0.0595	0.1638	0.5872	0.0009	0.0187	77.1	0.0054
	500	0.0806	0.2241	0.7257	0.0011	0.0252	111	0.0073
Forklifts Composite		0.0585	0.2257	0.4330	0.0006	0.0231	54.4	0.0053
Forklifts-Propane	25	0.0124	1.9683	0.0550	0.0000	0.0068	10.3	0.1042
	50	0.0023	0.2932	0.0984	0.0000	0.0016	18.3	0.0191
	120	0.0039	1.4083	0.1724	0.0000	0.0028	31.2	0.0330
	175	0.0055	2.2550	0.2663	0.0000	0.0058	65.1	0.0460
Forklifts-Propane Composite								
Generator Sets	15	0.0157	0.0698	0.1063	0.0002	0.0061	10.2	0.0014
	25	0.0276	0.0951	0.1632	0.0002	0.0096	17.6	0.0025
	50	0.0959	0.2734	0.2966	0.0004	0.0255	30.6	0.0087
	120	0.1206	0.4956	0.8099	0.0009	0.0640	77.9	0.0109
	175	0.1460	0.7413	1.3131	0.0016	0.0644	142	0.0132
	250	0.1372	0.4502	1.8047	0.0024	0.0508	213	0.0124
	500	0.1952	0.7617	2.5896	0.0033	0.0756	337	0.0176
	750	0.3257	1.2296	4.3019	0.0055	0.1241	544	0.0294
	9999	0.8673	3.0642	10.8871	0.0105	0.3104	1,049	0.0783
Generator Sets Composite		0.0832	0.3121	0.5779	0.0007	0.0351	61.0	0.0075
Graders	50	0.1182	0.3365	0.2882	0.0004	0.0286	27.5	0.0107
	120	0.1348	0.5355	0.8223	0.0009	0.0740	75.0	0.0122
	175	0.1554	0.7363	1.1931	0.0014	0.0688	124	0.0140
	250	0.1575	0.4508	1.5344	0.0019	0.0547	172	0.0142
	500	0.1947	0.6639	1.8193	0.0023	0.0671	229	0.0176
	750	0.4147	1.4022	3.9602	0.0049	0.1439	486	0.0374
Graders Composite		0.1533	0.6129	1.2503	0.0015	0.0649	133	0.0138
Off-Highway Tractors	120	0.2224	0.7269	1.2964	0.0011	0.1143	93.7	0.0201
	175	0.2135	0.8404	1.6085	0.0015	0.0923	130	0.0193
	250	0.1718	0.4896	1.5282	0.0015	0.0644	130	0.0155
	750	0.6814	3.0883	6.1417	0.0057	0.2515	568	0.0615
	1000	1.0246	4.8137	10.5080	0.0082	0.3620	814	0.0924
Off-Highway Tractors Composite		0.2170	0.7878	1.7969	0.0017	0.0871	151	0.0196
Off-Highway Trucks	175	0.1533	0.7593	1.1072	0.0014	0.0666	125	0.0138
	250	0.1469	0.3944	1.3513	0.0019	0.0461	167	0.0133
	500	0.2263	0.6661	1.9463	0.0027	0.0705	272	0.0204
	750	0.3695	1.0792	3.2612	0.0044	0.1164	442	0.0333

Table 48

SCAB Fleet Average Emission Factors (Diesel)

2012

Air Basin	SC

		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Equipment	**MaxHP**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**CO2**	**CH4**
	1000	0.5790	1.7854	6.4025	0.0063	0.1933	625	0.0522
Off-Highway Trucks Composite		0.2241	0.6635	2.0158	0.0027	0.0715	260	0.0202
Other Construction Equipment	15	0.0118	0.0617	0.0737	0.0002	0.0028	10.1	0.0011
	25	0.0160	0.0544	0.1019	0.0002	0.0044	13.2	0.0014
	50	0.0842	0.2740	0.2707	0.0004	0.0228	28.0	0.0076
	120	0.1104	0.5320	0.7540	0.0009	0.0633	80.9	0.0100
	175	0.1008	0.5880	0.8599	0.0012	0.0467	107	0.0091
	500	0.1517	0.5426	1.6573	0.0025	0.0545	254	0.0137
Other Construction Equipment Composite		0.0925	0.3847	0.8599	0.0013	0.0366	123	0.0083
Other General Industrial Equipment	15	0.0066	0.0391	0.0466	0.0001	0.0018	6.4	0.0006
	25	0.0185	0.0632	0.1170	0.0002	0.0045	15.3	0.0017
	50	0.1085	0.2856	0.2332	0.0003	0.0253	21.7	0.0098
	120	0.1274	0.4542	0.7277	0.0007	0.0703	62.0	0.0115
	175	0.1349	0.5757	1.0001	0.0011	0.0599	95.9	0.0122
	250	0.1235	0.3281	1.2983	0.0015	0.0417	136	0.0111
	500	0.2232	0.6772	2.2367	0.0026	0.0758	265	0.0201
	750	0.3707	1.1162	3.8016	0.0044	0.1273	437	0.0334
	1000	0.5621	1.8453	6.4018	0.0056	0.1947	560	0.0507
Other General Industrial Equipment Composite		0.1635	0.5362	1.4520	0.0016	0.0632	152	0.0148
Other Material Handling Equipment	50	0.1506	0.3950	0.3243	0.0004	0.0352	30.3	0.0136
	120	0.1239	0.4423	0.7103	0.0007	0.0684	60.7	0.0112
	175	0.1703	0.7292	1.2706	0.0014	0.0759	122	0.0154
	250	0.1305	0.3496	1.3863	0.0016	0.0443	145	0.0118
	500	0.1590	0.4876	1.6124	0.0019	0.0545	192	0.0143
	9999	0.7467	2.4395	8.4619	0.0073	0.2565	741	0.0674
Other Material Handling Equipment Composite		0.1566	0.5108	1.4125	0.0015	0.0613	141	0.0141
Pavers	25	0.0255	0.0811	0.1531	0.0002	0.0080	18.7	0.0023
	50	0.1451	0.3680	0.3038	0.0004	0.0327	28.0	0.0131
	120	0.1467	0.5107	0.8788	0.0008	0.0776	69.2	0.0132
	175	0.1864	0.7833	1.4495	0.0014	0.0819	128	0.0168
	250	0.2182	0.6365	2.0698	0.0022	0.0818	194	0.0197
	500	0.2383	0.9957	2.2418	0.0023	0.0883	233	0.0215
Pavers Composite		0.1596	0.5445	0.8980	0.0009	0.0642	77.9	0.0144
Paving Equipment	25	0.0153	0.0520	0.0974	0.0002	0.0042	12.6	0.0014
	50	0.1239	0.3124	0.2591	0.0003	0.0279	23.9	0.0112
	120	0.1150	0.3997	0.6897	0.0006	0.0610	54.5	0.0104
	175	0.1455	0.6114	1.1384	0.0011	0.0640	101	0.0131
	250	0.1349	0.3946	1.2976	0.0014	0.0507	122	0.0122
Paving Equipment Composite		0.1204	0.4365	0.8114	0.0008	0.0570	68.9	0.0109
Plate Compactors	15	0.0050	0.0263	0.0314	0.0001	0.0013	4.3	0.0005
Plate Compactors Composite		0.0050	0.0263	0.0314	0.0001	0.0013	4.3	0.0005
Pressure Washers	15	0.0075	0.0334	0.0509	0.0001	0.0029	4.9	0.0007
	25	0.0112	0.0385	0.0662	0.0001	0.0039	7.1	0.0010
	50	0.0349	0.1074	0.1339	0.0002	0.0102	14.3	0.0032
	120	0.0332	0.1458	0.2385	0.0003	0.0172	24.1	0.0030
Pressure Washers Composite		0.0173	0.0635	0.0921	0.0001	0.0063	9.4	0.0016
Pumps	15	0.0133	0.0508	0.0790	0.0001	0.0054	7.4	0.0012
	25	0.0386	0.1051	0.1803	0.0002	0.0117	19.5	0.0035
	50	0.1155	0.3229	0.3362	0.0004	0.0299	34.3	0.0104
	120	0.1250	0.5036	0.8226	0.0009	0.0669	77.9	0.0113
	175	0.1498	0.7431	1.3164	0.0016	0.0664	140	0.0135
	250	0.1357	0.4345	1.7375	0.0023	0.0501	201	0.0122
	500	0.2089	0.8032	2.6861	0.0034	0.0803	345	0.0188
	750	0.3557	1.3279	4.5700	0.0057	0.1350	571	0.0321
	9999	1.1456	4.0641	14.2305	0.0136	0.4081	1,355	0.1034

Table 48

SCAB Fleet Average Emission Factors (Diesel)

2012

Air Basin	SC

		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Equipment	**MaxHP**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**CO2**	**CH4**
Pumps Composite		0.0813	0.2983	0.4999	0.0006	0.0351	49.6	0.0073
Rollers	15	0.0074	0.0386	0.0461	0.0001	0.0018	6.3	0.0007
	25	0.0162	0.0549	0.1029	0.0002	0.0045	13.3	0.0015
	50	0.1105	0.2994	0.2677	0.0003	0.0263	26.0	0.0100
	120	0.1054	0.4098	0.6619	0.0007	0.0574	59.0	0.0095
	175	0.1320	0.6220	1.0725	0.0012	0.0591	108	0.0119
	250	0.1347	0.4083	1.4103	0.0017	0.0498	153	0.0122
	500	0.1755	0.6752	1.8093	0.0022	0.0652	219	0.0158
Rollers Composite		0.1038	0.4107	0.6936	0.0008	0.0488	67.1	0.0094
Rough Terrain Forklifts	50	0.1315	0.3910	0.3455	0.0004	0.0330	33.9	0.0119
	120	0.1038	0.4364	0.6425	0.0007	0.0585	62.4	0.0094
	175	0.1444	0.7268	1.1204	0.0014	0.0652	125	0.0130
	250	0.1353	0.3896	1.4082	0.0019	0.0458	171	0.0122
	500	0.1894	0.5985	1.8577	0.0025	0.0642	257	0.0171
Rough Terrain Forklifts Composite		0.1093	0.4680	0.6995	0.0008	0.0587	70.3	0.0099
Rubber Tired Dozers	175	0.2209	0.8528	1.6304	0.0015	0.0945	129	0.0199
	250	0.2545	0.7124	2.1985	0.0021	0.0942	183	0.0230
	500	0.3345	1.5220	2.8822	0.0026	0.1210	265	0.0302
	750	0.5042	2.2809	4.4100	0.0040	0.1832	399	0.0455
	1000	0.7807	3.6654	7.7816	0.0060	0.2729	592	0.0704
Rubber Tired Dozers Composite		0.3114	1.2491	2.6866	0.0025	0.1137	239	0.0281
Rubber Tired Loaders	25	0.0205	0.0697	0.1295	0.0002	0.0052	16.9	0.0018
	50	0.1315	0.3756	0.3242	0.0004	0.0319	31.1	0.0119
	120	0.1045	0.4187	0.6404	0.0007	0.0576	58.9	0.0094
	175	0.1312	0.6288	1.0135	0.0012	0.0583	106	0.0118
	250	0.1330	0.3838	1.3129	0.0017	0.0462	149	0.0120
	500	0.1961	0.6755	1.8555	0.0023	0.0677	237	0.0177
	750	0.4044	1.3812	3.9115	0.0049	0.1408	486	0.0365
	1000	0.5480	1.9543	6.3337	0.0060	0.1909	594	0.0494
Rubber Tired Loaders Composite		0.1272	0.4855	1.0034	0.0012	0.0558	109	0.0115
Scrapers	120	0.1990	0.7011	1.1749	0.0011	0.1054	93.9	0.0180
	175	0.2172	0.9158	1.6429	0.0017	0.0945	148	0.0196
	250	0.2367	0.6699	2.1849	0.0024	0.0859	209	0.0214
	500	0.3333	1.3000	3.0162	0.0032	0.1190	321	0.0301
	750	0.5779	2.2380	5.3231	0.0056	0.2075	555	0.0521
Scrapers Composite		0.2916	1.0984	2.5680	0.0027	0.1087	262	0.0263
Signal Boards	15	0.0072	0.0377	0.0450	0.0001	0.0017	6.2	0.0006
	50	0.1270	0.3587	0.3564	0.0005	0.0324	36.2	0.0115
	120	0.1284	0.5269	0.8360	0.0009	0.0703	80.2	0.0116
	175	0.1661	0.8370	1.4268	0.0017	0.0750	155	0.0150
	250	0.1746	0.5516	2.1599	0.0029	0.0639	255	0.0158
Signal Boards Composite		0.0203	0.0940	0.1470	0.0002	0.0083	16.7	0.0018
Skid Steer Loaders	25	0.0211	0.0635	0.1189	0.0002	0.0067	13.8	0.0019
	50	0.0596	0.2332	0.2402	0.0003	0.0180	25.5	0.0054
	120	0.0482	0.2769	0.3536	0.0005	0.0286	42.8	0.0043
Skid Steer Loaders Composite		0.0534	0.2360	0.2686	0.0004	0.0207	30.3	0.0048
Surfacing Equipment	50	0.0513	0.1441	0.1411	0.0002	0.0128	14.1	0.0046
	120	0.1040	0.4251	0.6895	0.0007	0.0557	63.8	0.0094
	175	0.0950	0.4745	0.8195	0.0010	0.0422	85.8	0.0086
	250	0.1095	0.3526	1.1993	0.0015	0.0413	135	0.0099
	500	0.1631	0.6813	1.7819	0.0022	0.0622	221	0.0147
	750	0.2601	1.0660	2.8642	0.0035	0.0986	347	0.0235
Surfacing Equipment Composite		0.1362	0.5467	1.3678	0.0017	0.0512	166	0.0123
Sweepers/Scrubbers	15	0.0124	0.0729	0.0870	0.0002	0.0034	11.9	0.0011
	25	0.0237	0.0808	0.1501	0.0002	0.0060	19.6	0.0021

Table 48

SCAB Fleet Average Emission Factors (Diesel)

2012

Air Basin	SC

		(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Equipment	**MaxHP**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**CO2**	**CH4**
	50	0.1195	0.3565	0.3179	0.0004	0.0302	31.6	0.0108
	120	0.1233	0.5204	0.7534	0.0009	0.0706	75.0	0.0111
	175	0.1575	0.8008	1.2212	0.0016	0.0717	139	0.0142
	250	0.1205	0.3447	1.3019	0.0018	0.0402	162	0.0109
Sweepers/Scrubbers Composite		0.1278	0.5215	0.7403	0.0009	0.0576	78.5	0.0115
Tractors/Loaders/Backhoes	25	0.0199	0.0662	0.1250	0.0002	0.0061	15.9	0.0018
	50	0.1006	0.3305	0.3030	0.0004	0.0267	30.3	0.0091
	120	0.0760	0.3557	0.4910	0.0006	0.0432	51.7	0.0069
	175	0.1058	0.5866	0.8294	0.0011	0.0478	101	0.0095
	250	0.1264	0.3755	1.2813	0.0019	0.0415	172	0.0114
	500	0.2386	0.7714	2.2621	0.0039	0.0784	345	0.0215
	750	0.3611	1.1563	3.5105	0.0058	0.1199	517	0.0326
Tractors/Loaders/Backhoes Composite		0.0862	0.3824	0.5816	0.0008	0.0435	66.8	0.0078
Trenchers	15	0.0099	0.0517	0.0617	0.0001	0.0024	8.5	0.0009
	25	0.0398	0.1355	0.2519	0.0004	0.0101	32.9	0.0036
	50	0.1656	0.4176	0.3536	0.0004	0.0374	32.9	0.0149
	120	0.1354	0.4732	0.8257	0.0008	0.0709	64.9	0.0122
	175	0.2050	0.8694	1.6306	0.0016	0.0901	144	0.0185
	250	0.2483	0.7418	2.3854	0.0025	0.0951	223	0.0224
	500	0.3135	1.4011	3.0220	0.0031	0.1190	311	0.0283
	750	0.5949	2.6307	5.8034	0.0059	0.2259	587	0.0537
Trenchers Composite		0.1507	0.4749	0.6995	0.0007	0.0582	58.7	0.0136
Welders	15	0.0111	0.0425	0.0660	0.0001	0.0045	6.2	0.0010
	25	0.0224	0.0609	0.1044	0.0001	0.0068	11.3	0.0020
	50	0.1071	0.2854	0.2637	0.0003	0.0260	26.0	0.0097
	120	0.0708	0.2687	0.4376	0.0005	0.0387	39.5	0.0064
	175	0.1183	0.5475	0.9688	0.0011	0.0531	98.2	0.0107
	250	0.0909	0.2704	1.0791	0.0013	0.0329	119	0.0082
	500	0.1154	0.4072	1.3538	0.0016	0.0431	168	0.0104
Welders Composite		0.0703	0.2150	0.2702	0.0003	0.0243	25.6	0.0063

Source: File offroadEF07_25.xls, downloaded from http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html

Table 49

Highest (Most Conservative) EMFAC2007 (version 2.3)
Emission Factors for On-Road Passenger Vehicles & Delivery Trucks

Projects in the SCAQMD (Scenario Years 2007 - 2026)

Derived from Peak Emissions Inventory (**Winter**, **Annual**, **Summer**)

Vehicle Class:

Passenger Vehicles (<8500 pounds) & Delivery Trucks (>8500 pounds)

The following emission factors were compiled by running the California Air Resources Board's EMFAC2007 (version 2.3) Burden Model, taking the weighted average of vehicle types and simplifying into two categories:

Passenger Vehicles & Delivery Trucks.

These emission factors can be used to calculate on-road mobile source emissions for the vehicle categories listed in the tables below, by use of the following equation:

Emissions (pounds per day) = N x TL x EF

where N = number of trips, TL = trip length (miles/day), and EF = emission factor (pounds per mile)

This methodology replaces the old EMFAC emission factors in Tables A-9-5-J-1 through A-9-5-L in Appendix A9 of the current SCAQMD CEQA Handbook. All the emission factors account for the emissions from start, running and idling exhaust. In addition, the ROG emission factors include diurnal, hot soak, running and resting emissions, and the PM10 & PM2.5 emission factors include tire and brake wear.

Scenario Year: **2012**

All model years in the range 1968 to 2012

Passenger Vehicles (pounds/mile)	
CO	**0.00765475**
NOx	**0.00077583**
ROG	**0.00079628**
SOx	**0.00001073**
PM10	**0.00008979**
PM2.5	**0.00005750**
CO2	**1.10152540**
CH4	**0.00007169**

Delivery Trucks (pounds/mile)	
CO	**0.01545741**
NOx	**0.01732423**
ROG	**0.00223776**
SOx	**0.00002667**
PM10	**0.00064975**
PM2.5	**0.00054954**
CO2	**2.76628414**
CH4	**0.00010668**

Source: File onroadEF07_26.xls, downloaded from http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html

Table 50
Highest (Most Conservative) EMFAC2007 (version 2.3)
Emission Factors for On-Road Heavy-Heavy-Duty Diesel Trucks
Projects in the SCAQMD (Scenario Years 2007 - 2026)
Derived from Peak Emissions Inventory (**Winter**, **Annual**, **Summer**)

Vehicle Class:
Heavy-Heavy-Duty Diesel Trucks (33,001 to 60,000 pounds)

The following emission factors were compiled by running the California Air Resources Board's EMFAC2007 (version 2.3) Burden Model and extracting the **Heavy-Heavy-Duty Diesel Truck (HHDT)** Emission Factors.

These emission factors can be used to calculate on-road mobile source emissions for the vehicle/emission categories listed in the tables below, by use of the following equation:

Emissions (pounds per day) = N x TL x EF

where N = number of trips, TL = trip length (miles/day), and EF = emission factor (pounds per mile)

The **HHDT-DSL** vehicle/emission category accounts for all emissions from heavy-heavy-duty diesel trucks, including start, running and idling exhaust. In addition, ROG emission factors account for diurnal, hot soak, running and resting emissions, and the PM10 & PM2.5 emission factors account for tire and brake wear.

The **HHDT-DSL, Exh** vehicle/emission category includes only the exhaust portion of PM10 & PM2.5 emissions from heavy-heavy-duty diesel trucks.

Scenario Year: **2012**
All model years in the range 1968 to 2012

HHDT-DSL (pounds/mile)	
CO	**0.01021519**
NOx	**0.03092379**
ROG	**0.00252764**
SOx	**0.00004042**
PM10	**0.00149566**
PM2.5	**0.00129354**
CO2	**4.21590774**
CH4	**0.00011651**

HHDT-DSL, Exh (pounds/mile)	
PM10	**0.00135537**
PM2.5	**0.00124837**

Source: File onroadEFHHDT07_26.xls, downloaded from http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html

Table 51
Motor Vehicle Entrained Road Dust Emission Factors

Vehicle Type	Surface	Silt Loading (sL, g/m2) or Silt Content (s, %)[a]	Average Weight (W) (tons)[b]	Un-controlled PM10 Emission Factor (lb/VMT)[c]	Un-controlled PM2.5 Emission Factor (lb/VMT)[c]	Control Efficiency (%)[d]	Controlled PM10 Emission Factor (lb/VMT)[e]	Controlled PM2.5 Emission Factor (lb/VMT)[e]
1/2-Ton Pick-up Truck, 4x4	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
1/2-Ton Pick-up Truck, 4x4	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Tool Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Tool Truck	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Pickup 4x4	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Pickup 4x4	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Survey Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Survey Truck	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
10-cu. yd. Concrete Mixer Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
10-cu. yd. Concrete Mixer Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
10-cu. yd. Dump Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
10-cu. yd. Dump Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
1-Ton Crew Cab Flat Bed, 4x4	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
1-Ton Crew Cab Flat Bed, 4x4	Unpaved	7.5	5	1.24E+00	1.24E-01	57%	5.32E-01	5.32E-02
1-Ton Crew Cab, 4x4	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
1-Ton Crew Cab, 4x4	Unpaved	7.5	5	1.24E+00	1.24E-01	57%	5.32E-01	5.32E-02
22-Ton Manitex	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
22-Ton Manitex	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
3/4-Ton Pick-up Truck, 4x4	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
3/4-Ton Pick-up Truck, 4x4	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
30-Ton Crane Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
30-Ton Crane Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
3 Drum Straw Line Puller	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
3 Drum Straw Line Puller	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
40' Flat Bed Truck/Trailer	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
40' Flat Bed Truck/Trailer	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
80ft. Hydraulic Manlift/Bucket Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
80ft. Hydraulic Manlift/Bucket Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Aggregate Base Delivery Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Aggregate Base Delivery Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Asphalt Delivery Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Asphalt Delivery Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Auger Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Auger Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Boom Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Boom Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Bucket Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Bucket Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Carry-all Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Carry-all Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Concrete Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Concrete Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Crew Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Crew Truck	Unpaved	7.5	5	1.24E+00	1.24E-01	57%	5.32E-01	5.32E-02
Crewcab Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Crewcab Truck	Unpaved	7.5	5	1.24E+00	1.24E-01	57%	5.32E-01	5.32E-02
Crushed Rock Delivery Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Crushed Rock Delivery Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Dump Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Dump Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Delivery Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Delivery Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Dump Truck (Trash)	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Dump Truck (Trash)	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02

Table 51
Motor Vehicle Entrained Road Dust Emission Factors

Vehicle Type	Surface	Silt Loading (sL, g/m2) or Silt Content (s, %)[a]	Average Weight (W) (tons)[b]	Un-controlled PM10 Emission Factor (lb/VMT)[c]	Un-controlled PM2.5 Emission Factor (lb/VMT)[c]	Control Efficiency (%)[d]	Controlled PM10 Emission Factor (lb/VMT)[e]	Controlled PM2.5 Emission Factor (lb/VMT)[e]
Extendable Flat Bed Pole Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Extendable Flat Bed Pole Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Flat Bed Truck/Trailer	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Flat Bed Truck/Trailer	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Flatbed Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Flatbed Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Foreman Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Foreman Truck	Unpaved	7.5	5	1.24E+00	1.24E-01	57%	5.32E-01	5.32E-02
Line Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Line Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Low Bed Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Low Bed Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Lowboy Truck/Trailer	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Lowboy Truck/Trailer	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Maintenance Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Maintenance Truck	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Pumper/Tanker Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Pumper/Tanker Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Reel Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Reel Truck	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Rodder Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Rodder Truck	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Splice Lab Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Splice Lab Truck	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Splicing Lab	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Splicing Lab	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Splicing Rig	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Splicing Rig	Unpaved	7.5	10	1.69E+00	1.69E-01	57%	7.26E-01	7.26E-02
Stake Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Stake Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Static Truck/Tensioner	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Static Truck/Tensioner	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Tool Trailer	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Tool Trailer	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Troubleman Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Troubleman Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Truck, Semi Tractor	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Truck, Semi Tractor	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Van	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Van	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Water Truck	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Water Truck	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Wire Truck/Trailer	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Wire Truck/Trailer	Unpaved	7.5	17	2.14E+00	2.14E-01	57%	9.22E-01	9.22E-02
Worker Commute	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Worker Commute	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Subtransmission Line Inspection	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Subtransmission Line Inspection	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02
Substation Site Visit	Paved	0.035	3.2	8.01E-04	0.00E+00	0%	8.01E-04	0.00E+00
Substation Site Visit	Unpaved	7.5	3.2	1.01E+00	1.01E-01	57%	4.35E-01	4.35E-02

[a] Paved road silt loading from ARB Emission Inventory Methodology 7.9, Entrained Paved Road Dust (1997) for collector roads, http://www.arb.ca.gov/ei/areasrc/fullpdf/full7-9.pdf
Unpaved road silt content from SCAQMD CEQA Handbook, (1993) Table A9-9-E-1 for overburden
[b] Average paved on-road vehicle weight in Riverside County from ARB Emission Inventory Methodology 7.9, Entrained Paved Road Dust (1997)

Table 51
Motor Vehicle Entrained Road Dust Emission Factors

Vehicle Type	Surface	Silt Loading (sL, g/m2) or Silt Content (s, %)[a]	Average Weight (W) (tons)[b]	Un-controlled PM10 Emission Factor (lb/VMT)[c]	Un-controlled PM2.5 Emission Factor (lb/VMT)[c]	Control Efficiency (%)[d]	Controlled PM10 Emission Factor (lb/VMT)[e]	Controlled PM2.5 Emission Factor (lb/VMT)[e]

Unpaved worker commuting weight on access road assumed to be same as paved road weight

Unpaved weight for other trucks is based on upper limit of 33,000 lbs for medium heavy-duty trucks.

[c] Equations:

EF(paved) = k_p $(sL/2)^{0.65}$ $(W/3)^{1.5}$ - C — Ref: AP-42, Section 13.2.1, "Paved Rods," November 2006

EF (unpaved) = k_u $(s/12)^a$ $(W/3)^b$ — Ref: AP-42, Section 13.2.2, "Unpaved Rods," November 2006

Constants:

k_p =	0.016	(Particle size multiplier for PM10)
	0.0024	(Particle size multiplier for PM2.5)
C =	0.00047	(Exhaust, brake wear and tire wear adjustment, PM10)
	0.00036	(Exhaust, brake wear and tire wear adjustment, PM2.5)
k_u =	1.5	(Particle size multiplier for PM)
	0.15	(Particle size multiplier for PM2.5)
a =	0.9	for PM10
	0.9	for PM2.5
b =	0.45	for PM10
	0.45	for PM2.5

[d] Control efficiency from limiting speeds on unpaved roads to 15 mph, from Table XI-A, Mitigation Measure Examples, Fugitive Dust from Construction & Demolition, http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/MM_fugitive.html

[e] Controlled emission factor [lb/mi] = Uncontrolled emission factor [lb/mi] x (1 - Control efficiency [%] / 100)

Table 52
Fugitive Dust Emission Factors
Soil Dropping During Excavation

Emission Factor [lb/cu. yd] = 0.0011 x (mean wind speed [mi/hr] / 5)$^{1.3}$ / (moisture [%] / 2)$^{1.4}$ x (number drops per ton) x (density [ton/cu. yd])
Reference: AP-42, Equation (1), Section 13.2.4, November 2006

Parameter	Value	Basis
Mean Wind Speed	12	SCAQMD CEQA Air Quality Handbook (1993), Table 9-9-G, default
Moisture	10.6	Preliminary geotechnical investigation of substation site
Number Drops	4	Assumption
Soil Density	1.215	Table 2.46, Handbook of Solid Waste Management

PM10 Emission Factor (Uncontrolled)	1.62E-03	lb/cu. yd
Reduction from Watering Twice/Day[b]	0%	
Controlled PM10 Emission Factor	1.62E-03	lb/cu. yd
Controlled PM2.5 Emission Factor[a]	3.36E-04	lb/cu. yd

[a] PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction of PM10 in Construction Dust = 0.208 from Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds, SCAQMD, October 2006

[b] Watering is assumed to be used to maintain moist conditions, so no further reduction from watering is included.

Emissions [pounds per day] = Controlled emission factor [pounds per cubic yard] x Volume soil handled [cubic yards per day]

Storage Pile Wind Erosion

Emission Factor [lb/day-acre] = 0.85 x (silt content [%] / 1.5) x (365 / 235) x (percentage of time unobstructed wind exceeds 12 mph / 15)
Reference: SCAQMD CEQA Air Quality Handbook (1993), Table 9-9-E

Parameter	Value	Basis
Silt Content	26.7	Preliminary geotechnical investigation of substation site
Pct. time wind > 12 mph	100	Worst-case assumption

PM10 Emission Factor (Uncontrolled)	156.7	lb/day-acre
Reduction from Watering Twice/Day	90%	Control efficiency from watering storage pile by hand at a rate of 1.4 gallons/hour-yard^2, Table XI-B, Mitigation Measure Examples, Fugitive Dust from Materials Handling, http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/MM_fugitive.html
Controlled PM10 Emission Factor	15.7	lb/day-acre
Controlled PM2.5 Emission Factor[a]	3.3	lb/day-acre

[a] PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction of PM10 in Construction Dust = 0.208 from Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds, SCAQMD, October 2006

Emissions [pounds per day] = Controlled emission factor [pounds per acre-day] x Storage pile surface area [acres]

Bulldozing, Scraping and Grading

Emission Factor [lb/hr] = 0.75 x (silt content [%])$^{1.5}$ / (moisture)$^{1.4}$
Reference: AP-42, Table 11.9-1, July 1998

Parameter	Value	Basis
Silt Content	26.7	Preliminary geotechnical investigation of substation site
Moisture	10.6	Preliminary geotechnical investigation of substation site

PM10 Emission Factor (Uncontrolled)	3.797	lb/hr
Reduction from Watering Twice/Day	61%	Control efficiency from watering three times per day, Table XI-A, Mitigation Measure Examples, Fugitive Dust from Construction & Demolition, http://www.aqmd.gov/ceqa/handbook/mitigation/fugitive/MM_fugitive.html
Controlled PM10 Emission Factor	1.481	lb/hr
Controlled PM2.5 Emission Factor[a]	0.308	lb/hr

[a] PM2.5 emission factor [lb/hr] = PM10 emission factor [lb/hr] x PM2.5 fraction of PM10

PM2.5 Fraction of PM10 in Construction Dust = 0.208 from Appendix A, Final–Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds, SCAQMD, October 2006

[b] Watering is assumed to be used to maintain moist conditions, so no further reduction from watering is included.

Emissions [pounds per day] = Controlled emission factor [pounds per hour] x Bulldozing, scraping or grading time [hours/day]

SF_6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emissions Source

J. Blackman, *Program Manager, U.S. Environmental Protection Agency,*
M. Averyt, *ICF Consulting,* and Z. Taylor, *ICF Consulting*

***Abstract*—This paper highlights a recent collaborative study between the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems and the electric power industry to investigate SF_6 leak rates from high voltage circuit breakers manufactured and installed between 1998 and 2002. Information from over 2,300 circuit breakers were analyzed to quantify the frequency of leaks and to estimate the weighted average annual leak rate for this population of circuit breakers. The methodology, data, and results of this study are presented.**

***Index Terms*-- SF_6, annual leak rate, greenhouse gas emissions, circuit breaker.**

I. Introduction

SULFUR hexafluoride (SF_6) is a gaseous dielectric used in high voltage electrical equipment as an insulator and/or arc quenching medium. SF_6 is the most potent greenhouse gas with a global warming potential that is 23,900 times greater than that of carbon dioxide (CO_2); it is also very persistent in the atmosphere with a lifetime of 3,200 years [1]. Potential sources of SF_6 emissions occur from: 1) losses through poor gas handling practices during equipment installation, maintenance and decommissioning; and 2) leakage from SF_6-containing equipment. The operation and maintenance of SF_6 gas carts, which are used to remove, store, clean, and re-fill SF_6 gas to high-voltage equipment, are considered a major source of handling-related losses. Equipment leakage, on the other hand, is the result of the deterioration of SF_6-containing equipment fittings and materials with time and use through chemical, hardening, and corrosion effects.

Equipment leakage is one of the two potential sources of SF_6 emissions. Leak detection surveys have noted that approximately 10 percent of circuit breaker populations may leak [2, 3], and of these leaking populations, 15 percent of the breaker leaks were minor, with repairs that could be conducted immediately, while the remaining 85 percent were considered significant and had to be referred to operations for scheduled repairs [3]. In terms of where these leaks typically occur, studies have noted that the majority occurs at gas mechanisms (73 percent), 21 percent from worn or broken bushings, and 6 percent from gas tanks [4]. Typically, such losses can only be mitigated through equipment repair or replacement. As electrical equipment ages and reaches the end of its operational service life, replacement rather than equipment repair may provide the more attractive SF_6 mitigation strategy. Many equipment manufacturers now guarantee minimal to zero leak rates for new equipment. Additionally, industry standards recommend that new equipment be built to low leakage limits [5]. Since there is little published information on new equipment leak rates, in a study initiated in 2004, EPA sought to obtain an improved understanding of average leak rates associated with newly manufactured equipment (i.e., installed between 1998 and 2002).

This paper provides a brief review of the data and results of an equipment study funded by EPA [6]. The remainder of this paper is organized into four sections:

- Section II describes the methodology of the field study, including study scope and data parameters.
- Section III provides a summary of the data compiled from utilities participating in the study.
- Section IV presents the results of the equipment leak rate analyses.
- Section V summarizes the conclusions drawn from the study.

II. Field Study Methodology

Section II defines the scope of the study and describes the data collection and compilation process.

A. Study Scope and Data Parameters

The scope of the study was limited to data from three Partner utilities. Information was requested on high voltage circuit breakers manufactured and installed between 1998 and 2002. SF_6 equipment can take the form of sealed or closed pressure systems. Only closed pressure system breakers were included in the study; circuit breakers that are defined as "sealed-for-life" were not addressed by this study. The period in which equipment leakage was assessed was defined as from 1998 through 2005. For purposes of this study, a circuit breaker was classified as leaking if it had documented "top-ups" of SF_6, which occur after a density alarm is sounded, indicating that 10 percent of the circuit breaker gas volume

J. Blackman is with U.S. EPA, Washington, D.C., USA (e-mail: Blackman.Jerome@epa.gov). M. Averyt and Z. Taylor are with ICF Consulting, Washington, D.C. USA (e-mail: maveryt@icfconsulting.com; ztaylor@icfconsulting.com).

has been emitted.

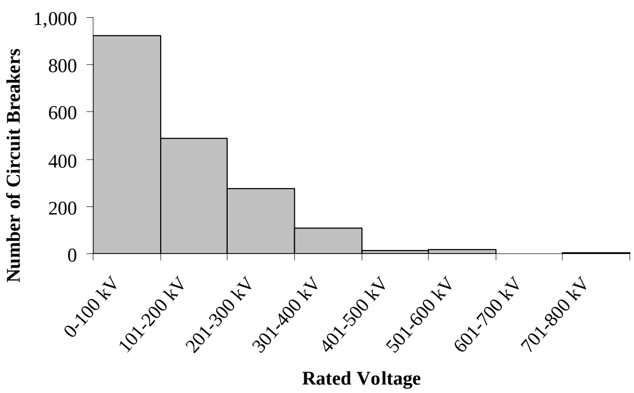
B. Data Collection and Compilation

The data collection was undertaken through a survey form via telephone and email correspondence. The form requested information on the utilities entire inventory of SF_6 breakers, defined by the study scope, including makes, models and installed quantities, number of breaker operations, and for leaking breakers, the quantity of SF_6 gas used during the “top-up” operation.

III. Data Summary

To ensure confidentiality, the names of the utilities involved in the study are not listed. The data provided covered equipment ranging from 33kV to 800kV. In total, information was provided on 2,329 circuit breakers. Figure I illustrates the proportion of circuit breakers size by standard rated voltage. As shown, the majority of the equipment included in the study fell into the range of less than 100 kV. Only 148 breakers were greater 300 kV.

FIGURE I
NUMBER OF CIRCUIT BREAKER BY RATED VOLTAGE



Of the 2,329 circuit breakers, 170 (7.3 percent) were reported as leaking.

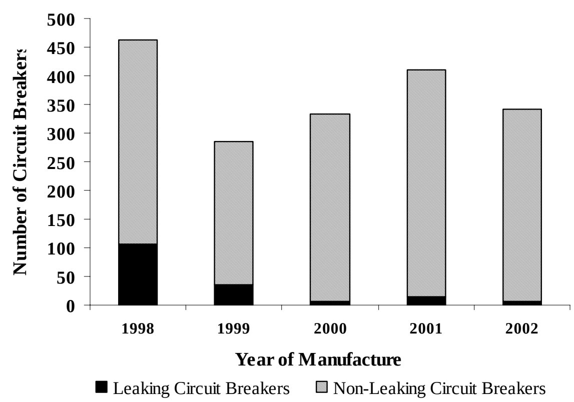
Table I and Figure II present a summary of the number of circuit breakers, leaking and non-leaking, included in the study.

TABLE I
SUMMARY OF LEAKING/NON-LEAKING CIRCUIT BREAKERS

Year of Manufacture	Leaking CB[a]	Non-Leaking CB[b]	Total CB	Leaking CB/Total CB	Leaking as % of Overall Total Leaking
1998	106	357	463	23%	62%
1999	35	250	285	12%	21%
2000	7	326	333	2%	4%
2001	15	396	411	4%	9%
2002	7	334	341	2%	4%
Total	**170**	**1,663**	**1,833[c]**		**100%**

[a]CB – Circuit Breakers
[b]No alarm triggered
[c]Number of circuit breakers does not total 2,329 because year of CB manufacture data are not available for all non-leaking circuit breakers.

FIGURE II
NUMBER OF CIRCUIT BREAKERS BY YEAR OF MANUFACTURE



For the circuit breakers in the data set that were manufactured in 1998, 23 percent were identified as leaking. These circuit breakers account for approximately 62 percent of the total number of leaking breakers. This result is intuitive considering the natural deterioration of seals and equipment over time.

Table II presents emissions data related to the leaking circuit breakers for each year of manufacture. Total emissions of SF_6 are indicated for the leaking circuit breakers manufactured in each year. Total emissions as a percent of total nameplate capacity associated with the leaking circuit breakers are also presented.

TABLE II
SF_6 EMISSIONS FROM LEAKING CIRCUIT BREAKERS

Year Manu-factured	Total Emissions (lbs. SF_6)	No. Leaking CBs	Total Emissions as % of Nameplate Capacity[a]
1998	2,859	106	6%
1999	302	35	0.96%
2000	24	7	0.07%
2001	140	15	0.29%
2002	81	7	0.12%
Total	**3,407**	**170**	

[a]Nameplate capacity of leaking circuit breakers only.

Consistent with the observations in Table I, circuit breakers manufactured in 1998 were also the largest contributors to SF_6 emissions reported in the study. Their emissions as a function of total SF_6-contained in the equipment (nameplate capacity), is approximately 6 percent, significantly larger than the values reported for leaking breakers manufactured in 1999 through 2002.

IV. Leak Rate Results and Analysis

Section IV presents the results of an analysis to define circuit breaker leak rates (as a percent of nameplate capacity) that are representative of the entire reported dataset. These estimates are referred to as the lower and upper bound leak rates, respectively, and are intended to illustrate potential industry trends. The key variables used to perform this analysis are 1) circuit breaker nameplate capacity, 2) total circuit breaker SF_6 leakage (lbs), and 3) the number of years that circuit breaker has been in operation.

Specifically, three leak rates (as a percent of nameplate capacity) were estimated. The first analysis generated a lower bound, or best case scenario, of an average circuit breaker leak rate estimate. The second two analyses both generated upper bound, or worst case scenario circuit breaker leak rate estimates, that are based on different methodologies and assumptions.

A. Lower Bound Weighted-Average Leak Rate

For the lower bound estimate, the weighted-average circuit breaker leak rate is approximately 0.2 percent per year. The lower bound leak rate was calculated by applying the raw reported data to Equation (1) and assuming that 1) through 2005, no additional “top-ups” have occurred after the last reported “top-up” (e.g., if the last reported “top-up was in 2003, it was assumed that no additional leakage occurred through 2005), and 2) for circuit breakers that have not reported any “top-ups” (i.e., they have not reached the 10 percent leakage threshold, and thus have not triggered a notification alarm), their emissions are zero.

This estimate is defined as the weighted average of circuit breaker annual leak rates as a percentage of SF_6 nameplate capacity, across all circuit breakers both leaking and non-leaking. The calculation for the weighted average annual leak rate per nameplate capacity is provided in Equation (1):

$$LC = \frac{\sum \frac{Q_{SF6i}}{Y_i}}{\sum C_i} \qquad (1)$$

Where:

LC = Weighted average annual leak rate per nameplate capacity (percent/year)

Q_{SF6i} = Total mass (i.e., lbs) of SF_6 for all top-up operations since installation for circuit breaker, i

Y_i = Number of years the circuit breaker, i, has been in use

C_i = Individual nameplate capacity for circuit breaker i (lbs SF_6)

B. Upper Bound Weighted-Average Leak Rate – Method 1

For the lower bound estimate, it was assumed that equipment that had not reported “top-ups” were not leaking; however, since “top-ups” are defined by density alarm triggers, it is possible that many more breakers had leaked, but had not reached the 10 percent density alarm leak threshold. To account for potential leakage under the density alarm threshold, an upper bound leak rate estimate was developed based on the following assumptions:

(1) All circuit breakers that have not indicated an alarm trigger leaked slightly less than 10 percent of their capacity between their installation date and 2005. Thus, the 2,159 circuit breakers (93 percent) in the dataset which have no documented “top-ups” (and are assumed for the lower bound to have a leak rate of zero percent) are scaled to assume a leakage rate of 10 percent (this is an asymptotic upper bound).

(2) The second adjustment assumed that for previously identified leaking breakers (those that have reported “top-ups”), an additional 10 percent of capacity (i.e., another “top-up”) occurred between the last documented service call and 2005. For example, a circuit breaker with an annual leak rate of 5 percent whose last reported service call occurred one year before the company data submittal is assumed to have 10 percent additional leakage during that last year.

Based on these assumptions and the application of equation (1) the weighted-average upper bound estimate for circuit breaker leak rate is estimated to be 2.5 percent. This result represents a *worst case* upper bound leak rate.

C. Upper Bound Weighted-Average Leak Rate –Method 2

Since the second assumption listed in the prior section, may overestimate emissions from documented leaking circuit breakers, an additional upper bound estimate was calculated by redefining how additional “top-ups” for these circuit breakers are treated. That is, it was assumed that circuit breakers which are currently leaking will continue to leak at their current rate. That is, if a circuit breaker is calculated to have an existing leak rate of 2 percent per year per nameplate capacity between its installation and last reported top-up date, then it was assumed that this rate continues through the end of the study period. This alternative approach maintains the original assumptions for non-leaking circuit breakers by assuming a leakage of just under 10 percent has occurred since circuit breaker installation.

Based on these assumptions and the application of equation (1), the alternate weighted-average upper bound leak rate estimate is 2.4 percent.

V. CONCLUSION

For the study dataset, the lower and upper bound weighted-average leak rate estimates of 0.2 and 2.5 percent, respectively, represent the best and worst case scenarios for circuit breaker leakage. To put this into some context, NEMA's SF_6 management guidelines state, "…Over a 50 year service life the emission of SF_6 gas due to its use in electrical equipment will not exceed... 5% equipment leakage…" (i.e., 0.1 percent/year) [7]. Also, the IEC standard for new equipment leakage is 0.5 percent per year [5]. While the upper bound is significantly larger than both the NEMA and IEC guidelines, the lower bound leak rate estimate is comparable, and sits between the NEMA and IEC recommendations.

VI. ACKNOWLEDGMENT

The authors would like to acknowledge representatives from Eastern Research Group, Inc (ERG), the Electric Power Research Institute (EPRI), and the electric utilities, and original equipment manufacturers that assisted EPA in undertaking this study.

VII. REFERENCES

[1] IPCC, *Climate Change 1995: The Science of Climate Change.* Intergovernmental Panel on Climate Change; J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds; Cambridge University Press. Cambridge, U.K.

[2] McCreary, J.D., "AEP: A Case Study," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, November 2-3, 2000, San Diego, CA. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/mccrearyppt.pdf

[3] D. Keith, J. Fisher, and T. McRae, "Experience with Infrared Leak Detection on FPL Switchgear," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, November 2-3, 2000, San Diego, CA. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/fischerp.pdf

[4] Salinas, A. and Flores, M., "Southern California Edison: SF_6 Gas Management Program Update," presented at the International Conference on SF_6 and the Environment: Emission Reduction Technologies, December 1-3, 2004, Scottsdale, AZ. [Online]. Available: http://www.epa.gov/electricpower-sf6/pdf/dec04/Salinas_ok2use.pdf

[5] IEC, International Electrotechnical Commission Standard 62271-1, 2004.

[6] EPA, "High Voltage Circuit Breakers Field Study," prepared by EPRI and the Eastern Research Group, July, 2005.

[7] NEMA, "Management of SF_6 Gas for Use in Electrical Power Equipment," Ad-Hoc Task Group on SF_6, Switchgear Section (8-SG), February, 1998.

VIII. BIOGRAPHY

Jerome Blackman is Program Manager for EPA's SF_6 Emission Reduction Partnership for Electric Power Systems. Mr. Blackman joined EPA in 1995 and has work in several commercial/industrial non-regulatory voluntary pollution prevention programs within the Office of Atmospheric Programs.

Mollie Averyt is an Associate at ICF Consulting. Ms. Averyt specializes in environmental policy analyses related to climate change and ozone depletion issues; and provides support for EPA's SF_6 Emission Reduction Partnership.

Zephyr Taylor is a Research Assistant at ICF Consulting. Mr. Taylor specializes in quantitative modeling and analysis specifically related to climate change issues. Mr. Taylor provides technical support for EPA's SF_6 Emission Reduction Partnership.