Development of Methodologies for Calculating Greenhouse Gas Emissions from Electricity Generation for the California Climate Action Registry

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ABSTRACT

The California Climate Action Registry, which will begin operation in Fall 2002, is a voluntary registry for California businesses and organizations to record annual greenhouse gas emissions. Reporting of emissions in the Registry by a participant involves documentation of both "direct" emissions from sources that are under the entity's control and "indirect" emissions controlled by others. Electricity generated by an off-site power source is considered to be an indirect emission and must be included in the entity's report. Published electricity emissions factors for the State of California vary considerably due to differences in whether utility-owned out-of-state generation, non-utility generation, and electricity imports from other states are included. This paper describes the development of three methods for estimating electricity emissions factors for calculating the combined net carbon dioxide emissions from all generating facilities that provide electricity to Californians. We find that use of a statewide average electricity emissions factor could drastically under- or over-estimate an entity's emissions due to the differences in generating resources among the utility service areas and seasonal variations. In addition, differentiating between marginal and average emissions is essential to accurately estimate the carbon dioxide savings from reducing electricity use. Results of this work will be taken into consideration by the Registry when finalizing its guidance for use of electricity emissions factors in calculating an entity's greenhouse gas emissions.

Introduction

The California Climate Action Registry, which was initially established in 2000 and will begin operation in Fall 2002, is a voluntary registry for recording annual greenhouse gas (GHG) emissions (California Climate Action Registry, 2002). The purpose of the Registry is to assist California businesses and organizations in their efforts to inventory and document emissions in order to establish a baseline and to document early actions to increase energy efficiency and decrease GHG emissions. The State of California has committed to use its "best efforts" to ensure that entities that establish GHG emissions baselines and register their emissions will receive "appropriate consideration under any future international, federal, or state regulatory scheme relating to greenhouse gas emissions" (California Senate, 2001). Reporting of GHG emissions involves documentation of both "direct" emissions from sources that are under the entity's control and "indirect" emissions controlled by others. Electricity generated by an off-site power source is considered to be an indirect GHG emission and is required to be included in the entity's report (Arthur D. Little, Inc., 2002).

Registry participants include businesses, non-profit organizations, municipalities, state agencies, and other entities. Participants are required to register the GHG emissions of all operations in California, and are encouraged to report nationwide. For the first three years of participation, the Registry will only require the reporting of carbon dioxide (CO_2) emissions[1] although participants are encouraged to report the remaining five Kyoto Protocol GHGs (CH_4, N_2O, HFCs, PFCs, and SF_6). After three years, reporting of all six Kyoto GHG emissions is required (California Climate Action Registry, 2002).

The Ernest Orlando Lawrence Berkeley National Laboratory (Berkeley Lab) was asked to provide technical assistance to the California Energy Commission (CEC) in establishing methods for calculating average and marginal emission factors, both historic and current, as well as statewide and for sub-regions. This paper describes the results of that study which illustrated the use of three possible approaches but was not a rigorous estimation of actual emission factors (Marnay et al., 2002).

Published Electricity Emissions Factors for California

A number of existing GHG inventories, registries, and protocols provide annual average electricity emission factors for California.[2] These values, and a tabulation of what is included in the calculations, are provided in Table 1. As shown, the reported average annual emissions factors vary significantly, from 0.037 kgC/kWh to 0.125 kgC/kWh, due not only to different reporting years but also to whether imports, exports, utility-owned out-of-state generation and non-utility generation are included. These electricity emission factors are the only factors currently available to quantify CO_2 emissions associated with electricity generation for entities within California.

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[1] While emissions are referred to as CO_2, quantities of emissions are reported in mass of equivalent carbon, where 1 kg C = 0.27 kg CO_2. We focus on CO_2 emissions since emissions of the other GHGs from utilities are comparatively negligible. In 1999, U.S. electric utilities released approximately 532.6 MtC but only 2.3 MtCeq. of N_2O and less than 0.1 MtCeq. of NH_4. Additionally, fugitive emissions of SF_6 are released from substations and circuit breakers in the electrical transmission and distribution system. These emissions equaled approximately 7 MtCeq. (U.S. EPA 2001a).

[2] None of the published sources provide marginal electricity emission factors, factors for utility service districts, or monthly emission factors.

Table 1. Comparison of Published Average Annual Electricity CO2 Emission Factors for California

Source	Year(s)	Average Emission Factor (kgC/kWh)	Includes Utility-Owned In-State Generation	Includes Utility-Owned Out-Of-State Generation	Includes Non-Utility Generation	Includes Imported Electricity	Comments
Voluntary Reporting of GHGs – 1605(b)[1]	1997-99	0.037	Y	N	N	N	
Voluntary Reporting of GHGs – 1605(b)[1]	1992	0.094	Y	N	Y	N	Might include non-utility and/or imports – documentation unclear
ICLEI – e-Mission: GHG Strategy Software[2]	1998	0.125	Y	N	N	Y	Data drawn from DOE's State Energy Data Report; emissions from imports calculated using U.S. average EF
U.S. EPA National GHG Inventory[3]	1998	0.052	Y	N	Y	N	EF is for the Pacific Contiguous Census Division which includes Washington and Oregon
Emissions Inventory Improvement Program[4]	1995	0.114	Y	Y	Y	Y	
California Inventory of GHG Emissions[5]	1994	0.093	Y	N	Y	N	
E-GRID[6]	1998	0.059	Y	N	Y	N	

1 U.S. DOE/EIA. 2001. Updated State-Level Greenhouse Gas Emission Factors for Electricity Generation. http://tonto.eia.doe.gov/FTPROOT/environment/e-supdoc.pdf

2 Torrie Smith Associates. 2001. e-Mission Greenhouse Gas Strategy Software. http://torriesmith.com/

3 U.S. DOE/U.S. EPA. 2000. Carbon Dioxide Emissions from the Generation of Electric Power in the United States. http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html

4 U.S. EPA. 1999. Estimating Greenhouse Gas Emissions. Vol. VIII: Chapter 1 "Methods for Estimating Carbon Dioxide Emissions from Combustion of Fossil Fuels." http://www.epa.gov/ttnchie1/eiip/ techreport/volume08/index.html

5 California Energy Commission. 1998. 1997 Global Climate Change: Greenhouse Gas Emissions Reduction Strategies for California. Appendix A: Historical and Forecasted GHG Emissions Inventories for California. Sacramento, CA: California Energy Commission

6 LBNL calculation using EPA's E-GRID plant-level data on CO_2 emissions and net generation. See U.S. EPA 2001. E-GRID 2000. http://www.epa.gov/airmarkets/egrid/index.html

Developing Electricity Emissions Factors for California

The large variation in published electricity emissions factors indicates a further need to develop and compare methods that account for emissions from all sources providing power to California. Berkeley Lab developed three methods that yield not only annual statewide emissions factors but also factors for specific utility service areas, marginal emissions factors, and seasonal emissions factors.

The overall objective of this work was to develop methodologies for estimating *average emission factors* (AEFs) and *marginal emission factors* (MEFs) that can provide an estimate of the combined net CO_2 emissions from all generating facilities that provide electricity to California consumers. The methods developed cover the historic period from 1990 to the present, with 1990 and 1999 used as test years. The factors derived take into account the location and season of consumption, direct contracts for power which may have certain atypical characteristics (e.g., specific purchases of "green" electricity from renewable resources), resource mixes of electricity providers, import and export of electricity from utility-owned generation sources and other sources, and electricity from cogeneration.

It is assumed that the factors developed in this way will diverge considerably from simple statewide AEF estimates based on standardized inventory estimates that use conventions inconsistent with the goals of this work. A notable example concerns the treatment of imports and exports, which despite being a significant element in California's electricity supply picture, are excluded from inventory estimates of emissions that are based on geographical boundaries of the state.

Associating CO_2 emissions with electricity consumption encounters three major complications. First, electricity can be generated from a number of different primary energy sources, many of which are major sources of CO_2 emissions (e.g., coal combustion) while others result in virtually no CO_2 emissions (e.g., hydro). Second, the mix of generation resources used to meet electricity loads may vary at different times of day or in different seasons. Third, electrical energy is transported over long distances by complex transmission and distribution systems, so the emissions related to electricity usage can occur far from the jurisdiction in which that energy is consumed. In simpler terms, the emissions resulting from electricity consumption vary considerably depending how it is produced and when and where it is used.

The California electricity sector has undergone significant changes since 1990, and this creates some major challenges for establishing a consistent method of estimating emission factors from 1990 on. California is a particularly challenging state for calculating emission factors for several reasons: the fuel mix is among the most diverse in the nation; a large share of California's electricity is supplied by independent power producers, much of which is from combined heat and power[3]; several California utilities own shares of generating facilities in other states; California imports much of its electricity in addition to the power from these California owned out-of-state resources; and direct retail access was in effect from 1998 to 2001. Finally, specific data on non-utility generators are not available prior to 1998.

There is no practical way to identify where or how all the electricity used by a certain customer was generated, but by reviewing public sources of data the total emission burden of a customer's electricity supplier can be found and an AEF calculated. These are useful for assigning a net emission burden to a facility. In addition, MEFs for estimating the effect of changing levels of usage can be calculated. MEFs are needed because emission rates at the margin diverge from the average.[4]

Description of Three Methods for Calculating California Electricity Emissions Factors

Berkeley Lab developed three methods for calculating California electricity emissions factors. The first is an accounting method that draws primarily from public data sources (PDS). The second uses the Elfin model to simulate plant operations and estimate emissions for 1990. The third, used for the 1999 test year, is a spreadsheet that applies a simplified load duration curve (LDC). Table 2 compares these approaches and summarizes what is included in each approach.

[3] Total fuel consumption is reported by combined heat and power units on the U.S. Energy Information Administration survey forms, and several methodologies exist for determining how fuel consumption should be split between the heat and electric outputs. The approach used in this study assigned a fixed conversion efficiency of fuel input to useful thermal output and allocated the remaining fuel to electricity production.

[4] Note that this is not a *life cycle analysis*. These emission factors are intended to estimate only the emissions that take place within the boundaries of generating stations. Emissions incurred by the construction of electricity generation facilities and delivery infrastructure; by the extraction (including coalbed methane release), processing, and delivery of fuels to the power plant; or by utilities' support services (e.g. office buildings and maintenance operations) are not included. Even so, transmission and distribution losses should be included for purposes of the Registry. As such, it is recommended that Registry participants assume an average loss of 8% and divide the emission factors reported in this paper by 0.92 (A.D. Little, 2002; Marnay et al., 2002).

Table 2. Comparison of Three Methods for Estimating Emission Factors

Method	Year	Average Emission Factors	Marginal Emission Factors	Includes Imports	Includes Exports	Includes CA-Owned Out-Of-State Generation	Excludes Specific Purchases[a]
Public Data Sources	1999	Yes	No	Yes[b]	No	Yes	Yes
Elfin Model	1990	Yes	Yes	Yes	No	Yes	N/A
Load Duration Curve	1999	Yes	Yes	Yes[b]	No	Yes	Yes/No[c]

[a] "Specific Purchases" refers to purchases of electricity by retailers for use in green power products. Generation and associated emissions for these products should be separated from the resources providing power for the general pool of grid electricity to avoid double counting.
[b] Imports are net imports. Thus, exports are not treated explicitly but are subtracted from import totals.
[c] The LDC approach could include specific purchases; however, they have not been included here due to time limitations.

Public Data Sources Methodology

The first approach for deriving AEFs is an accounting method that draws primarily from U.S. Energy Information Administration (EIA) reporting forms, with some supplemental information from the CEC and the Federal Energy Regulatory Commission (FERC). This method was used to estimate emissions and derive AEFs for the 1999 test year.[5] Historical data on power plant generation and fuel consumption were used to determine plant-specific emissions. These were then aggregated into emission totals for each power control area (PCA)[6] as well as for the entire state.

Emissions from CHP units were assigned using a method of deducting fuel input for heat based on a standard conversion efficiency of fuel to useful thermal output. Electricity was assumed to serve the load of the PCA where it was generated, and data on PCA generation and loads were used to estimate electricity imports.[7] The shares of generation from out-of-state plants partially owned by California utilities were also assumed to serve these utilities' loads before other imports would be purchased.

Out-of-state emissions associated with imported electricity were calculated by multiplying the quantity of imported electricity by the AEF of the region from which the electricity was assumed to originate. *Specific purchases* of electricity for green power products and the associated emissions were subtracted from the totals of the PCA in which the electricity was generated.

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[5] The absence of data on non-utility generation and monthly utility loads precluded the use of the PDS approach to calculate emission factors for 1990.
[6] A power control area is defined as a grid region for which one utility controls the dispatch of electricity. Some smaller utilities are embedded in the power control areas of larger utilities.
[7] By late 1999, California's CAISO utilities had divested most of their thermal power plants to independent power producers; therefore, the relatively fixed relationship between customer load and the plant available to serve it no longer holds. For lack of precise sales data, a traditional fixed relationship is assumed in this report.

Elfin Model Methodology

The Elfin model was used to simulate plant operations and estimate emissions for 1990. This model was a widely used forecasting tool for California utility power systems during the 1980s and early 1990s, roughly until publication of the last biennial CEC Electricity Report for 1996. Fortunately, old data sets that were compiled and publicly scrutinized during this period are still available in the public domain and can be used to replicate historic conditions. Data sets for six electricity utility service territories were provided by CEC and all were run for 1990. Elfin has its own built-in plant and contract data for modeling emissions from cogeneration and imports. This model provides a great deal of versatility for determining emission factors. In addition to providing annual AEFs and MEFs for the state and each PCA, it can also estimate emission factors on a monthly basis as well as for other sub-periods, such as for on- and off-peak hours (CEC, 1990; CEC, 1993).

Load Duration Curve Methodology

The third methodology, used for the 1999 test year, is a spreadsheet that applies a simplified load duration curve (LDC), as many simulation models do (such as Elfin). The approach uses publicly available data from the National Energy Modeling System (NEMS) input files. The LDC model provides estimates of AEFs and MEFs by an approximation of the complex plant operation algorithms of more sophisticated models. In the LDC method, plants were placed in order of probable dispatch as follows: 1) nuclear plants, 2) non-thermal imports 3) renewables such as wind, geothermal, and biomass, 4) co-generation facilities, and 5) hydro. All remaining resources (thermal, non-cogeneration facilities) were then taken in order of their historic capacity factors, highest to lowest. The LDC model also makes the same assumption as the PDS approach regarding electricity serving the load of the PCA in which it was generated, although some results for the combined load of the California Independent System Operator (CAISO) are also presented. This is equivalent to treating the three CAISO utilities – Pacific Gas & Electric (PG&E), Southern California Electric (SCE), and San Diego Gas & Electric (SDG&E) as one PCA. Specific purchases have not been not separated from the generation totals, but the model can be adapted to do so. Cogeneration did not require additional assumptions as the NEMS data files contain plant-specific heat rates for calculating fuel consumption for electricity generation from CHP plants.

Results: California Electricity CO2 Emissions and Emissions Factors

Total Annual CO_2 Emissions from California Electricity Production

Total annual CO_2 emissions generated by the three approaches for the entire state, for the four major California utilities, and for the CAISO are shown in Table 3. The Elfin model methodology shows total CO_2 emissions of 26.1 MtC in 1990. Since the total state electricity load in 1999 was about 10 percent higher than in 1990, the larger total emissions of 29.5 MtC and 29.0 MtC yielded by the LDC and PDS methods, respectively, are to be expected. This ratio holds roughly true for all of the individual PCAs except PG&E. The higher PG&E

emissions reported by Elfin for 1990 are due largely to the fact that 1990 was a dry year, and natural gas plants were operated at greater capacity factors to compensate for lower hydro generation. For 1999, the LDC and PDS methods generated remarkably similar estimates of total CO2 emissions for both the entire state and each PCA.

Table 3. Comparison of Total Annual CO_2 Emissions from Three Electricity Emission Factors Calculation Methods

	1990 Emissions Using Elfin	1999 Emissions Using LDC	1999 Emissions Using PDS
LADWP	4.7	5.2	5.0
SCE	11.8	12.9	12.9
SDG&E	2.2	2.8	2.6
PG&E[a]	7.3	7.0	7.0
CAISO	21.3	22.7	22.5
California[b]	26.1	29.5	29.0

[a] LDC and PDS results for PG&E include Sacramento Municipal Utility District (SMUD).
[b] Includes irrigation districts and municipal utilities

Average Emissions Factors for California Electricity Production

The three approaches also yield remarkably consistent annual average emissions factors for the four PCAs (see Table 4). A principal finding here is that the level of CO_2 associated with electricity usage varies considerably among the PCAs, although it comes as no surprise that these values are lower for PG&E than for the southern California utilities. PG&E has a large share of carbon-free generation, such as hydro, nuclear, and predominantly hydro imports from the Pacific Northwest.

Table 4. Comparison of Annual Average Emissions Factors from Three Electricity Emission Factors Calculation Methods (kgC/kWh)

	1990 AEFs Using Elfin	1999 AEFs Using LDC	1999 AEFs Using PDS
LADWP	0.195	0.207	0.192
SCE	0.132	0.131	0.132
SDG&E	0.132	0.146	0.140
PG&E[a]	0.070	0.063	0.064
CAISO		0.101	
California[b]	0.110	0.105	0.108

[a] LDC and PDS results for PG&E include Sacramento Municipal Utility District (SMUD).
[b] Includes irrigation districts and municipal utilities

Marginal Emissions Factors for California Electricity Production

Table 5 shows that the LDC and Elfin methodologies produced quite divergent MEFs for all the PCAs except LADWP. (MEFs were not calculated using the PDS methodology). With the exception of LADWP, utility MEFs are significantly higher than the corresponding AEFs. The difference in Elfin's 1990 and LDC-derived 1999 MEFs for SCE is especially striking. The high 1999 MEF using the LDC method occurs because a large share of the gas-fired generation in this PCA is from cogeneration, which is assumed not to respond to changes in the load. Thus, the load-following resources consist largely of imports from the Southwest. The difference between the 1990 and 1999 MEFs is also large for PG&E, which has the greatest share of nuclear and hydro generation, two resources that are generally never curtailed to follow load. Since the MEFs of the PCAs other than LADWP range from 25% to over 200% greater than the corresponding AEFs, using AEFs to estimate CO_2 savings from reducing electricity usage would significantly underestimate actual savings.

Table 5. Comparison of Annual Marginal Emissions Factors from Three Electricity Emission Factors Calculation Methods[a] (kgC/kWh)

	1990 MEFs Using Elfin	1999 MEFs Using LDC	1999 MEFs Using PDS
LADWP	0.191	0.199	N/A
SCE	0.165	0.215	N/A
SDG&E	0.201	0.181	N/A
PG&E[b]	0.153	0.140	N/A
CAISO		0.193	

[a] MEFs were not calculated using the PDS methodology
[b] LDC results for PG&E include Sacramento Municipal Utility District (SMUD).

California Electricity Generation, CO_2 Emissions, and Average Emissions Factors Disaggregated by Source

Table 6 disaggregates California electricity generation, CO_2 emissions and average emissions factors in 1999 by their source based on the PDS results. In-state electricity generation accounts for 63% of total California electric use, while 14% is out-of-state production owned by California utilities and the remaining 23% is imported. Coal produces a negligible share of California's in-state electricity, but is by far the predominant source of energy in the Southwest U.S. Thus, imports from California-owned out-of-state coal plants and other utilities in the Southwest significantly increase California's CO_2 emissions and the AEFs. The emissions associated with electricity from California-owned out-of-state plants alone raises the AEF by a third. Thus, a simple inventory approach that only counts emissions within California's borders underestimates the CO_2 emissions from electricity actually consumed by California consumers, but does provide a good estimate of electricity-related emissions within the state.

Table 6. Total 1999 California Electricity Generation, CO_2 Emissions, and Average Emissions Factors Disaggregated by Source[a]

	In-State	CA owned Out-of-State[b]	In-State + CA owned Out-of-State	SW Imports[c]	NW Imports[d]	Total CA
Generation (TWh)	170.14	37.16	207.30	42.80	19.76	269.86
CO2 Emissions (MtC)	11.92	7.36	19.28	8.32	1.41	29.01
AEF (kgC/kWh)	0.070	0.198	0.093	0.194	0.071	0.108

[a] Calculated from public data sources.
[b] This refers to the generation shares of out-of-state plants owned by California utilities.
[c] This represents imports from the Southwest, a region that for purposes of this study includes Arizona, Nevada, New Mexico, Utah, and Colorado. The assumed share of imports from the Southwest is high due to assumption that southern California utilities receive all imports from this region. Precise sales data would permit allocation of a greater share of imports to the Northwest, which would lower the state total emissions. If the shares were the same as those reported in CEC 2001 (roughly 53% from the Northwest), total emissions would be about 5% lower.
[d] The Northwest region is composed of Montana, Wyoming, Idaho, Washington, and Oregon.

Seasonal Variation in Average Emissions Factors

The large share of seasonally varying hydro generation in California combined with typically hot late summer weather implies that AEFs may be higher when increased output from thermal generating sources must compensate for diminished hydro output. Conversely, as more thermal generation is used, the share of natural gas is likely to increase relative to coal, pushing down the AEF of thermal generation. Table 7 shows the AEFs calculated for May and October, months that usually have relatively high and low hydro generation, respectively. PG&E, the most hydro-dependent PCA, has by far the largest variation between the two months. This occurs both because more gas-fired generation is used within the PCA and more electricity is imported from the Northwest. The decrease in hydro generation also causes the AEF of the imported power to increase, as more coal-fired electricity is used to replace the reduction in hydropower. PG&E, being the largest PCA, is a large enough share of the statewide total load that the seasonal change in its resource mix significantly affects the statewide AEF. The variation in the other PCAs is much less pronounced being less influenced by differences in hydro output. This suggests that accounting for seasonal changes in resource mix, particularly for entities located in the PG&E service area, is important to accurately estimate emissions throughout the year.

Table 7. 1999 Seasonal Changes in Average Emissions Factors

Utility	May			October			Percent Difference Oct/May, PDS Total
	CA Generation, LDC[a]	CA Generation, PDS[a]	Total w/ Imports, PDS	CA Generation, LDC[a]	CA Generation, PDS[a]	Total w/ Imports, PDS	
PG&E	0.046	0.043	0.046	0.079	0.079	0.083	79%
SCE	0.086	0.083	0.122	0.111	0.105	0.132	8%
SDG&E	0.091	0.096	0.150	0.105	0.089	0.134	-11%
LADWP	0.205	0.194	0.192	0.208	0.184	0.184	-5%
California[a]	0.082	0.074	0.098	0.113	0.103	0.117	19%

[a] Includes the shares of out-of-state plants owned by CA utilities.
[b] Includes only the PCAs listed in the table.

Summary of Findings

Using three different methods to estimate annual AEFs, MEFs, and seasonal AEFs by utility PCAs, Berkeley Lab found that using a simple annual statewide AEF could significantly under- or over-estimate an entity's emissions responsibility due to the large variation in generating resources among the utility service areas.[8] Also, differentiating between marginal and average emissions is essential to accurately estimate the CO_2 savings from reducing electricity use. Seasonal differences in AEFs due to fluctuations in hydro generation should be accounted for at the statewide level, and particularly for the PG&E area. Overall, this study demonstrates that there are significant differences in CO_2 emissions factors from electricity generation, depending upon whether the factor represents average emissions, marginal emissions, utility service districts, and various seasons. Programs that estimate total annual CO2 emissions from electricity generation as well as programs that estimate CO_2 emissions reductions related to mitigation efforts should carefully choose the emissions factors that are used for calculating emissions from electricity.

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[8] Note, however, the dramatic restructuring of California's electricity sector that took place in 1998. In this work, estimated AEFs and MEFs for 1999 depend heavily on the assumption that attached generators serve the load of utlilities to which they are attached. Future work should explore alternative assumptions for years after 1998.

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