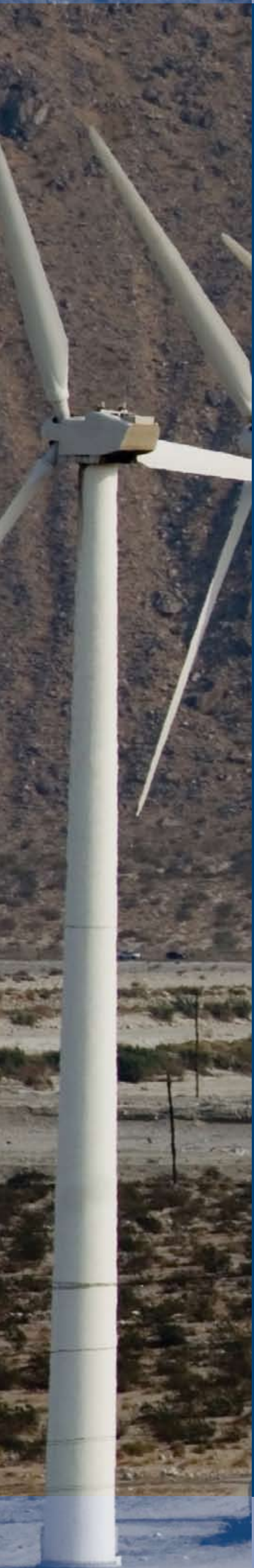

San Diego County Greenhouse Gas Inventory

An Analysis of Regional Emissions and Strategies to Achieve AB 32 Targets

Electricity Report

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Electricity Report Acknowledgements

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For an electronic copy of this report and the full documentation of the San Diego Greenhouse Gas Inventory project, go to www.sandiego.edu/epic/ghginventory.

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1. Introduction

Production and use of electricity is a significant source of greenhouse gas emissions (GHG). In San Diego County, the combination of emissions from power plants located in the region and electricity imported from outside the region accounts for about one quarter of regional GHG emissions. This report, a component of the San Diego County Greenhouse Gas Inventory project, provides an estimate of historical GHG emissions associated with electricity from 1990 to 2006 and future emissions to 2020 for San Diego County. Using emissions reduction targets codified in California's Global Warming Solutions Act of 2006 (AB 32) as a guide, this report also establishes emissions reductions targets for the region's electricity category. Although AB 32 does not require individual sectors or jurisdictions (e.g., cities and counties) to reduce emissions by a specific amount, the project team calculated the theoretical emissions reductions necessary in each emissions category (e.g., transportation, electricity, etc.) for San Diego County to reduce emissions to 1990 levels by 2020 – the statewide statutory target under AB 32. Finally, the report identifies and quantifies potential emissions reduction strategies to determine the feasibility of reducing electricity-related emissions to 1990 levels by 2020.

To the extent possible, the project team followed the same calculation methodology used by the California Air Resources Board (CARB) to develop the statewide GHG inventory. In some instances, when doing so could yield a more accurate or precise result, the project modified the CARB method.

This report, which is intended as an overview of the findings from research and analysis conducted for the electricity category, includes the following sections.

- Section 2 provides an overview of GHG emissions for electricity production and use in San Diego County, including total emissions, a breakdown of emissions by subcategory (residential, commercial, etc.), a summary of the highest emitting commercial building types and activities, projections to 2020, and reduction targets.

- Section 3 discusses the strategies necessary to reduce electricity-related emissions to 1990 levels by 2020.

- Section 4 provides a detailed discussion of the method used to estimate emissions for this category.

1.1. Key Findings

The key findings of the report are summarized below.

- In 2006, GHG emissions from the electricity sector totaled 9 million metric tons of carbon dioxide equivalent (MMT CO_2E), about 25% of San Diego County's overall emissions.

- Emissions from electricity use grew by about 2 MMT CO_2E (31%) between 1990 and 2006, exceeding population growth.

- Electricity use in the commercial sector accounted for 4 MMT CO_2E (44%) in 2006. The residential sector accounted for 3.1 MMT CO_2E (36%). Combined, these sectors represent 80% of total emissions from electricity use. The remaining emissions derive from agricultural, industrial, and other uses.

- Under the 2020 business-as-usual projection, emissions are expected to increase by 2 MMT CO_2E (28%).[1]

- The electricity sector would have to reduce its GHG contribution by just over 4 MMT CO_2E (40%) below the 2020 business-as-usual projection to meet AB 32 emissions reduction targets (1990 levels).

- To achieve the targets established in Executive Order S-3-05, reducing emissions 80% below 1990 levels by 2050, emissions from electricity would need to be about 1 MMT CO_2E (10 MMT CO_2E [88%] below the 2020 business-as-usual projection).

- Reducing emissions to 1990 levels by 2020 would require a combination of increasing renewable energy sources, enhancing energy efficiency, increased use of cogeneration, and purchasing cleaner fossil-fuel derived electricity.

- Achieving the existing Renewable Portfolio Standard of 20% renewable supply by 2010 and 33% by 2020 would reduce GHG emissions by 3 MMT CO_2E, accounting for 56% of the potential emissions reduction from the electricity sector.[2]

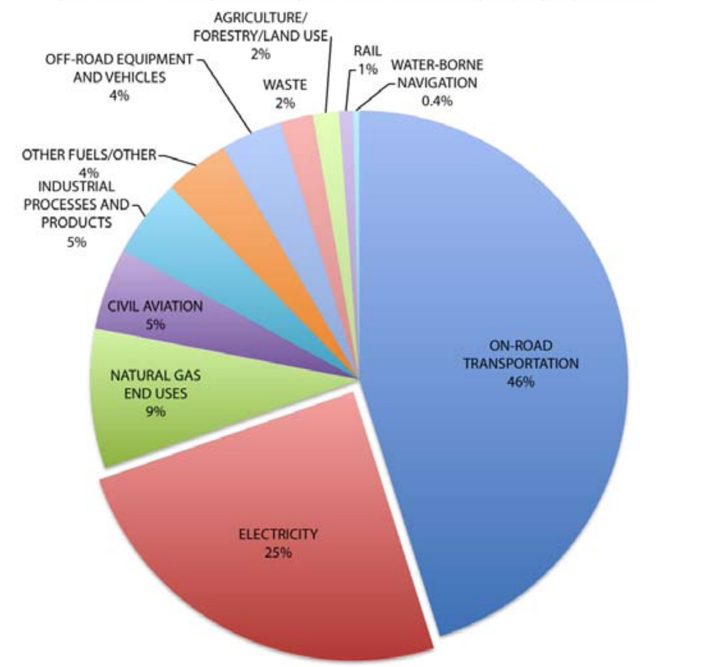
- Over the period from 1990 to 2006, approximately one-third of San Diego County's total energy supply was purchased from sources for which fuel use and location were unknown; therefore, any estimate of emissions from the electricity sector has some degree of uncertainty.

2. Greenhouse Gas Emissions From Electricity Production and Use

Electricity generation is a significant contributor to GHG emissions. As it does statewide, electricity accounts for about 25% of total emissions in the San Diego region (9 MMT CO_2E). Figure 1 shows the relative contribution of this category to San Diego County's total GHG emissions.

Electricity category totals include emissions from all electricity generated and consumed within the region and imported from outside the region but consumed in the region. Emissions from the following sources are included:

Figure 1. San Diego County GHG Emissions by Category (2006)



- **SDG&E-Owned Generation Assets.** Historically this included all of the large power plants in the region and several gas turbines. After electricity restructuring, these plants changed ownership but still operate in the region.

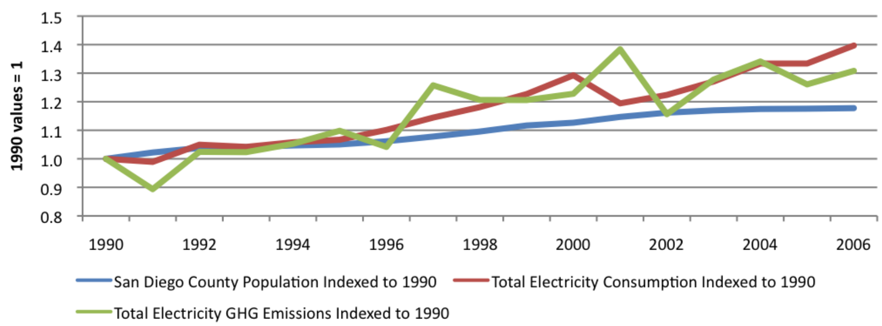
- **SDG&E Purchased Power.** This is all the electricity purchased by SDG&E to supplement their own generation, including energy from power plants located in the region and outside the region.

- **California Department of Water Resources (DWR) Contracts.** During the electricity crisis of 2000-2001, the DWR entered into contracts on behalf of the utilities in California. Several of these contracts were allocated to SDG&E.

- **Direct Access.** Electricity is supplied by entities other than SDG&E under existing direct-access contracts. (Emissions from this sector would not be included in an estimate of greenhouse gases for SDG&E only.)

- **Self-Serve Generation.** Emissions from electricity generated by individual customers for their own use is also included in the inventory. For example, if a customer has a distributed generation system and consumes all the energy from the system, this electricity is not included in the purchased power data, as no energy was sold to SDG&E.

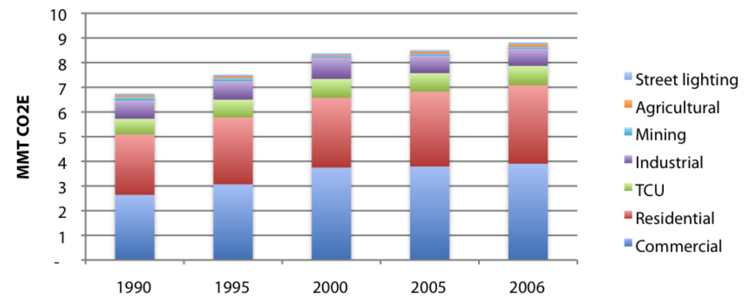
Figure 2. Growth of Population, Consumption, and GHG Emissions



Because all electricity consumed in the San Diego region is included in this emissions estimate, it will by definition vary from other estimates that cover SDG&E only, as given in the mandatory reporting process required by the California Air Resources Board or reported publicly through the California Climate Action Registry.

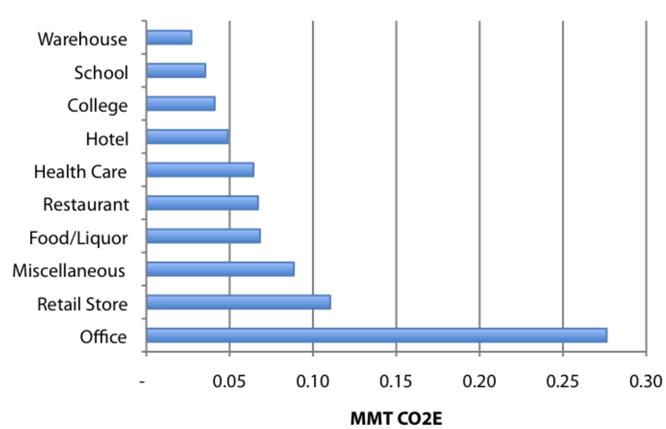
Emissions from electricity generation increased by 2 million metric tons of CO_2 equivalent (MMT CO_2E) or about 31% during the period 1990-2006. Historically, GHG emissions trends have mirrored those of electricity consumption and population growth. As shown in Figure 2, which indexes emissions, electricity use, and population growth to 1990 levels, in recent years GHG emissions from the electricity sector are growing faster than population growth.

Figure 3. GHG Emissions from Electricity by Sector



As the economy's greatest consumer of electricity, the commercial sector produces most of the associated GHG emissions. This sector is responsible for 4 MMT CO_2E (44%) of emissions, while the residential sector accounts for approximately 3 MMT CO_2E (36%). Transportation, communications, and utilities (TCU) accounts for 0.8 MMT CO_2E (9%), and San Diego County's relatively small industrial sector accounts for 0.7 MMT CO_2E (8%). Figure 3 shows the relative emissions of each sector for selected years from 1990 to 2006.

Figure 4. GHG Emissions by Commercial Building Type (2006)



Emissions within the commercial sector may be split between commercial buildings and other commercial activities.[3] Figure 4 shows the top 10 emitting commercial building types. Office buildings emit more than any other buildings type by a large margin.

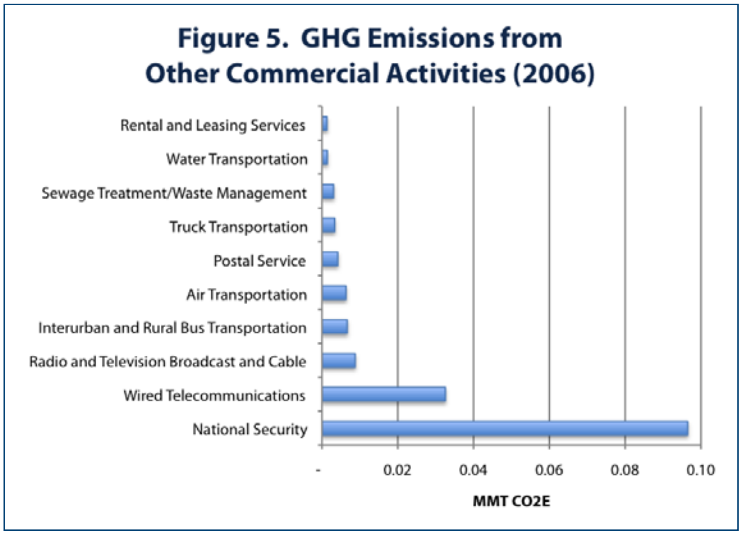
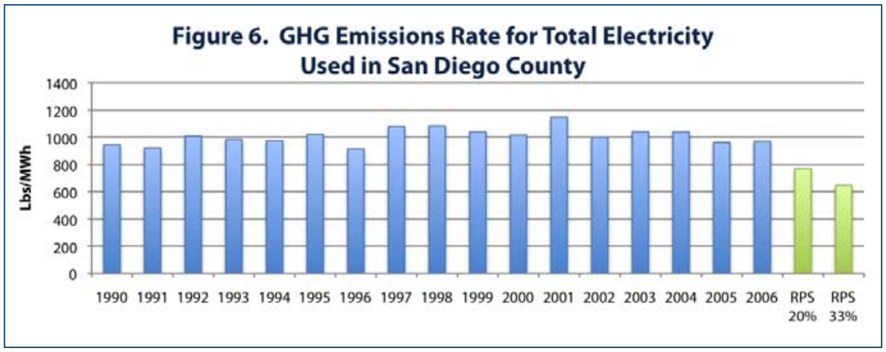


Figure 5 shows the top 10 emitting categories in the "commercial other" sector. National security activities, including military bases, emit nearly three times the amount of the next closest category, though they have significantly lower emissions than office buildings.

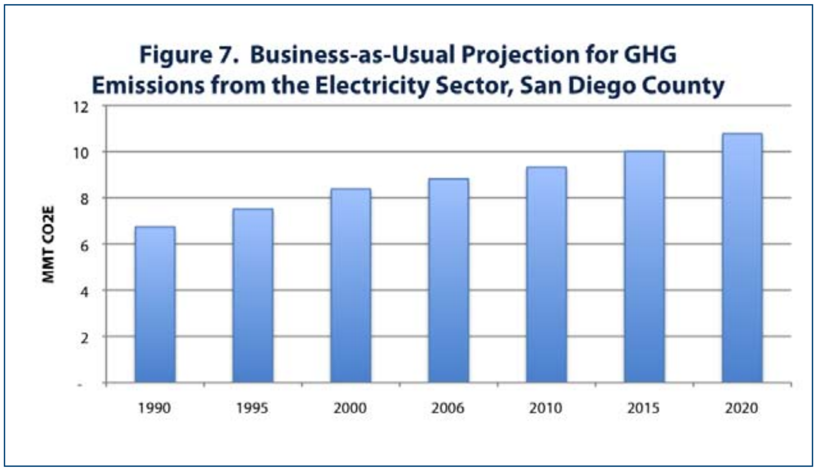
The emissions rate of the San Diego region's electricity sector, expressed in pounds per megawatt-hour, has remained relatively flat from 1990 through 2006 (Figure 5). The current emissions rate of 968 pounds per megawatt hour (lbs/MWh) is about 3% below 1990 levels. From 1990 through 1995, SDG&E purchased significant amounts of virtually emissions-free geothermal energy from the Mexican Commission Federal de Electricidad (CFE). Also, SDG&E's portion of the San Onofre Nuclear Generating Station (SONGS) represented a greater percentage of overall energy use in the early part of the time period evaluated.



Today, SDG&E's supply mix is mostly natural gas and nuclear with a growing portion of renewables. As SDG&E complies with the Renewable Portfolio Standard (RPS) requirement of 20% renewable sources by 2010, it is likely that the overall emissions rate will decline further. Figure 6 also shows the projected emissions rates as the 2010 target is met and if the RPS requirement is expanded to 33%.[4]

As mentioned above, it is important to note that the emissions rates presented here are for total energy supply for the San Diego region, including direct-access sales, which accounted for approximately 17% of total energy supply in 2006, and on-site electrical generation not sold to the utility.

2.1. Emissions Projections and Reduction Targets

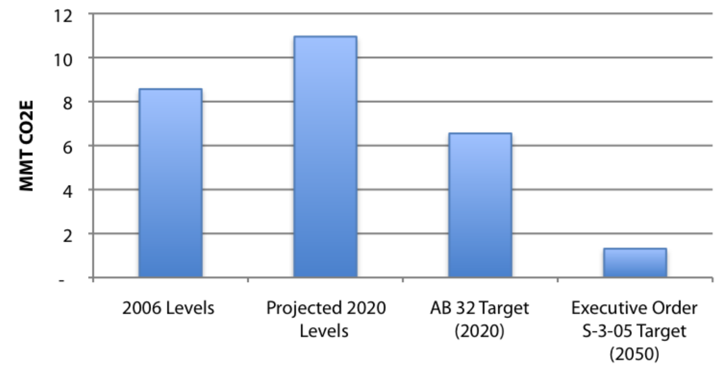


Given a business-as-usual trajectory, emissions from the electricity sector will be approximately 11 MMT CO_2E in 2020, a 28% increase over 2006 levels and a 67% increase over 1990 levels. Figure 7 shows the emissions levels under the business-as-usual scenario, which projects emissions at the 2006 rate of emissions (lbs/MWh) and assumes no other changes.[5, 6]

In 2006 Governor Arnold Schwarzenegger signed into law the Global Warming Solutions Act (AB 32), establishing statutory limits on GHG emissions in California. AB 32 seeks to reduce statewide GHG emissions to 1990 levels by the year 2020. Even though AB 32 does not specify reduction targets for specific sectors or jurisdictions, this study calculated theoretical reductions targets as if the statewide statutory emissions reductions targets were applied to San Diego County. To meet the targets established by AB 32 (1990 levels by 2020) the San Diego region would have to reduce its 2020 emissions from electricity use by 4 MMT CO_2E – a 40% reduction.

In 2005, Governor Schwarzenegger signed Executive Order S-3-05, which establishes long-term targets for GHG emissions reductions. It seeks to reduce emissions levels 80% below 1990 levels by 2050. While this reduction target is not law, it is generally accepted as the long-term target to which California regulations are aiming. Similar to AB 32, Executive Order S-3-05 is intended to be a statewide target, but if applied hypothetically to San Diego County, total emissions from electricity would have to be reduced to just over 1 MMT CO_2E –a reduction of 10 MMT CO_2E (88%) below the 2020 business-as-usual projection. Figure 8 shows projected 2020 and actual 2006 emissions levels compared to the AB 32 and Executive Order S-3-05 targets.

Figure 8. Hypothetical GHG Reduction Targets for the Electricity Category, San Diego County



3. Emissions Reductions Strategies (Wedges)

To reach emissions reductions targets set by AB 32, the electricity sector will have to reduce emissions by approximately 4 MMT CO_2E below the business as usual projection for 2020. Emissions in the electricity sector are driven primarily by total consumption and fuel type. One clear strategy is to reduce the total energy consumed in the region. Another significant strategy is to generate electricity from renewable sources that have nominal or no emissions.[7]

To illustrate how the region could achieve the AB 32 targets and reduce emissions by 4 MMT CO_2E, the project team developed several strategies and calculated the potential emissions reductions for each. The results were used to develop reduction "wedges," illustrated in Figure 9. This approach was adapted from the well-known study by Pacala and Socolow, demonstrating that global emissions could be reduced to levels that would stabilize climate change with existing technologies.[8] They

Table 1. Electricity Category Emissions Reduction Strategies (Wedges)

Emission Reduction Wedge	Emissions Reduction MMT CO_2E	Percentage of Total Reduction	Percentage of AB 32 Goal for Electricity
Renewable Portfolio Standard 20%	2.0	37%	45%
Renewable Portfolio Standard 33% (Incremental)	1.1	20%	24%
Reduce Electricity Consumption 10%	1.0	19%	23%
Cleaner Electricity Purchases (≤1100 lbs/MWh)	0.6	12%	15%
Replace Boardman Contract	0.3	5%	6%
Increase CHP by 200 MW	0.2	4%	5%
400 MW of Distributed Photovoltaics	0.2	4%	5%
Total	**5.4**	**100%**	**122%**

took the total reductions needed to stabilize emissions and split that amount into equal parts or wedges, each wedge representing a certain amount of emissions reduction. The project team followed a similar approach to show how the San Diego region might reduce its GHG emissions to meet AB 32 targets.

The team developed seven wedges to reduce GHG emissions from the electricity sector to 1990 levels. Each wedge is based in part on existing statutes, policy directives currently under consideration, or contractual terms (in the case of the Boardman power plant). Table 1 shows each wedge and the amount of emissions that it could reduce by 2020. The combined emissions reduction represented by these seven wedges is 5 MMT CO_2E, more than the total amount needed to reach the 1990 levels by 2020. The potential emissions reductions from the electricity sector represent approximately one third of the reductions needed from all sectors to meet the AB 32 target.

The order in which one calculates each wedge affects the magnitude of each wedge and the overall emissions reduction amount. This is because there are interactions between and among the wedges such that one wedge can affect the potential emissions reduction of another. In reality, all wedges would take place simultaneously, but to estimate the magnitude of each wedge, it was necessary to calculate the wedges discretely. For simplicity, the project team chose to calculate the wedges in an order based on the Energy Action Plan's loading order: energy efficiency, renewable energy, distributed generation, clean fossil-fuel generation.[9]

Figure 9. Electricity Emissions Reduction Strategies
San Diego County

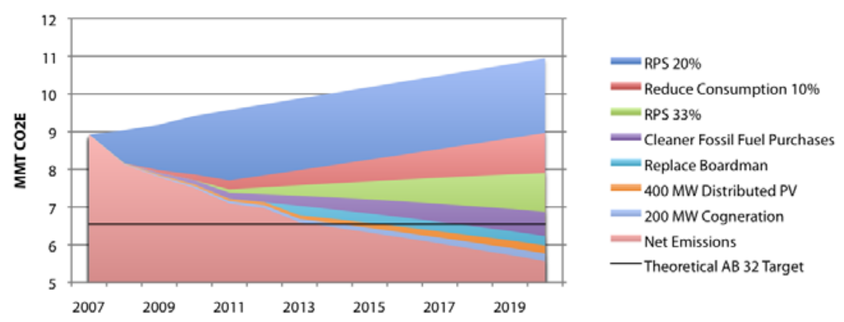


Figure 9 shows how each wedge reduces emissions from the business-as-usual projection.

3.1. Renewable Portfolio Standard – 20% by 2010

California's Renewable Portfolio Standard (RPS) requires the state's three investor-owned utilities to provide at least 20% of energy supplies from renewable sources by 2010.[10] According to the California Public Utilities Commission, California's three major utilities supplied, on average, 13% of their 2006 retail electricity sales with renewable power.[11] SDG&E currently supplies about 6% of its sales with renewable energy.[12] To calculate the potential emissions reduction to meet the 20% RPS, we assumed the current level of 6% and that SDG&E attains its 20% goal by 2010 – a 14% percentage point increase. Achieving the 20% standard would yield 2 MMT CO_2E in GHG emissions reductions, representing about 37% of all the emissions reductions from the electricity sector.[13]

3.2. Renewable Portfolio Standard – 33% by 2020

The California Energy Commission's Integrated Energy Policy Report for 2007 recommends increasing the RPS to 33% by 2020.[14] In recent years, legislation has been introduced to codify this policy, but none has yet been approved.[15] For purposes of the wedge analysis, we calculated the impact of supplying 33% of all regional energy needs with renewables by 2020. The reductions associated with achieving a 33% standard would be 1 MMT CO_2E, or about 20% of the total reductions from the electricity sector. The combined effect of achieving the current 20% standard and incremental renewable additions from a 33% standard would represent 57% of all reductions needed from the electricity sector.

3.3. Reduce Electricity Use by 10% by 2020

California has been a leader in energy efficiency since the 1970s. California has some of the most aggressive building and appliance standards in the nation and historically has had effective electric energy efficiency programs funded by a public benefits charge paid by all customers. Per-capita energy consumption in California has remained relatively flat over the past three decades due in large part to these standards and programs. Reducing overall consumption and demand for electricity is a key component in the state's overall energy infrastructure planning policy. The Energy Action Plan's loading order emphasized energy efficiency and lowering demand as preferred "resources."[16] Such reductions are also preferred to reduce greenhouse gases.

Determining the amount of electricity consumption that can be reduced by 2020 is complex, and no single policy exists to achieve such a goal; rather, a combination of existing rules and regulations is evolving to contribute to significant reductions in the total electricity consumed statewide. It is also possible that future legislation will initiate regulatory changes to accelerate electricity savings. The project team considered these factors when determining reasonable amounts of electricity reduction.

Energy efficiency programs funded by the customers of electric and natural gas utilities are a significant factor. The California Public Utilities Commission (CPUC) has regulatory jurisdiction over investor-owned utility expenditures for energy efficiency.[17] An ongoing proceeding is considering the potential for long-term savings from these "public goods charge" energy efficiency programs. Itron Inc. has conducted a detailed analysis of this potential for this proceeding.[18] Initial results for the SDG&E service area suggest a potential for electricity reductions ranging from a base-case of approximately 6% to a midrange case of 8% of projected total energy supply by 2020.[19] These amounts include savings from energy efficiency programs and from naturally occurring savings, those that would have occurred even without financial incentives and other program activities; but they do not include savings from large industrial customers, of which the San Diego region has few, or new appliance and building standards, both of which can have a significant impact on energy use. Using the Itron analysis as a base, the project team calculated the GHG emissions associated with a 10% reduction in total energy use in the region by 2020, which would result in a 1 MMT CO_2E reduction.

Given the uncertainty of steps to achieve emissions reductions from energy efficiency, the project team chose to develop a general energy reduction wedge rather than try to predict exactly how these savings would be realized. Energy reductions associated with this wedge likely will be achieved through a combination of efficiency programs, appliance and new building standards, and other possible policy and statutory changes, including requirements for zero-energy buildings and efficiency upgrades when existing buildings change ownership.

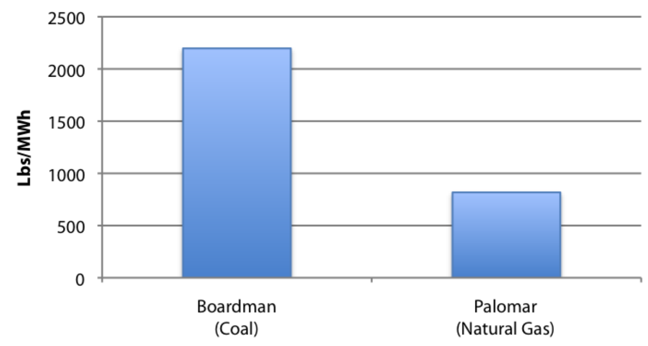
In Decision 07-10-032, the CPUC established a policy goal for all new residential construction to be zero net energy by 2020 and for all commercial construction to be zero net energy by 2030.[20] Two pending bills in the California legislature seek to codify this goal by establishing zero-energy standards for commercial buildings by 2020 and residential buildings by 2030.[21] Further, AB 1109, approved in 2007, will develop efficient lighting standards, which are likely to result in significant energy savings over time.[22] Finally, in their Draft Scoping Plan, the CARB recommended a 10% reduction in energy usage via energy efficiency.[23]

3.4. Replace the Boardman Power Plant Contract with Clean Fossil Fuel Generation

Fuel type is the main factor in determining the level of GHG emissions from electricity generation. Coal is the most carbon-intensive fuel used to generate electricity for large-scale use. SDG&E does not own any coal-fired power plants; nevertheless, it is unclear precisely how much coal-derived electricity is included in its total electricity portfolio. SDG&E has a contract with Portland General Electric in Oregon to purchase energy from the Boardman Power Plant, which uses coal to generate electricity. The contract is set to expire in 2013.[24] Replacing energy generated by the Boardman plant with energy from a state-of-the-art, combined-cycle natural gas power plant would yield significant net GHG emissions reductions.

In 2006, the Boardman plant emitted greenhouse gases at a rate of 2,197 pounds per megawatt-hour (lbs/MWh). By comparison, SDG&E's new Palomar plant had an emissions rate of 818 lbs/MWh (Figure 10). If the Boardman plant were replaced starting in 2014 with energy generated from a plant equivalent to the Palomar plant, assuming the 2006 level of energy purchased from Boardman is projected into the future, GHG emissions would be reduced by 0.3 MMT CO_2E annually.

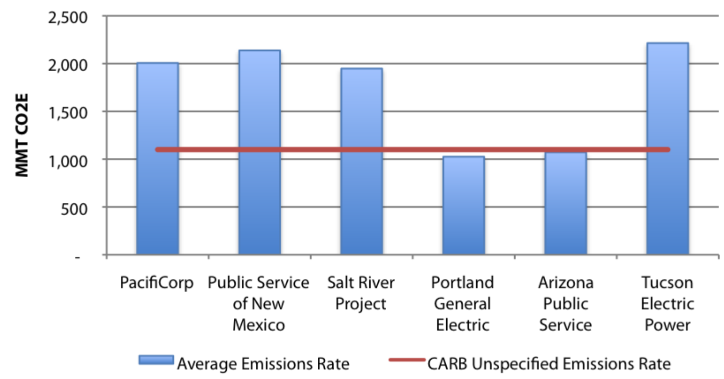
Figure 10. Emissions from Boardman and Palomar Plants (2006)



3.5. Purchase Cleaner Fossil Fuel Electricity

In addition to the Boardman power plant, SDG&E has purchased fossil fuel-generated electricity from other electric utilities over the past decade, including Pacificorp, Public Service of New Mexico, Tucson General Electric, Arizona Public Service, and Salt River Project. Each of these utilities has a different average emissions profile depending on the fuel mix used to generate electricity. Figure 11 shows the 2006 average emissions rates for all electricity generated by these utilities compared to the CARB default rate of 1,100 lbs/MWh, which is used to estimate GHG emissions from electricity when the fuel and geographical location of the power plant are unknown. Assuming that future electricity purchases are similar in quantity to those of 2006, if all electricity purchased from these entities had an emissions rate equal to the CARB default rate, 0.6 MMT CO_2E would be avoided. This estimate does not include the additional savings that could be realized if all unspecified power purchases, which represent significantly more electricity than that purchased from the utilities presented here, were for electricity with an average emissions rate of 1,100 lbs/MWh.

Figure 11. Average Emissions Rate for Sample of SDG&E Purchased Electricity Sources (2006)



3.6. Increase Cogeneration Capacity to 200 MW by 2020

Generating electricity is generally an inefficient process. Nationally in 2007, the average generation efficiency rate was 35%. This means nearly 65% of all of the primary energy used to generate electricity is wasted as exhaust heat.[25] One way to improve this process is to capture this heat and apply it to a useful purpose. Modern combined-cycle gas plants are more efficient than their single-cycle predecessors in part because they use waste heat. Cogeneration – also called combined heat and power (CHP) – is another way to improve the overall efficiency of electricity production. In this case, heat produced by the combustion process is captured to heat air or water or used in an absorption chiller to create cold water for air conditioning. Increasing use of cogeneration in the region would reduce overall GHG emissions. A 2005 report by the Electric Power Research Institute and the California Energy Commission estimates that 155-420 MW of additional cogeneration potential exists in the SDG&E service territory, depending on adoption of policies and programs to promote cogeneration.[26] On the basis of these figures, under moderate market access and with the ability to export electricity into wholesale markets, the project team estimated that the SDG&E service territory could increase total cogeneration capacity by 200 MW, yielding a GHG emissions reduction of 0.2 MMT CO_2E by 2020.

To determine this emissions reduction, the project team calculated the difference between cogeneration and combined-cycle gas turbine, the likely other option for generating baseload electricity. Emissions from cogeneration were derived using an analysis by Energy and Environmental Economics, Inc. (E3), which showed that cogeneration installations would emit between 1024 and 1102 lbs/MWh during the period from 2009 through 2020.[27] Emissions from cogeneration are divided roughly equally between the production of electricity and thermal energy for other uses. For simplicity, the project team credited the electricity sector the amount of GHG savings associated with the thermal energy; that is, the amount of emissions avoided by using waste heat in lieu of natural gas for thermal needs. For natural gas combined-cycle emissions, the team used an emissions rate of 818 lbs/MWh, equal to that of SDG&E's Palomar plant in Escondido for 2006. Emissions savings would increase if compared to either the average emissions rate of the San Diego region or to peaking electricity resources.

3.7. Installation of 400 MW of Distributed Photovoltaics by 2020

In Decision D.06-12-033, the CPUC authorized expenditure of over $2 billion to fund the California Solar Initiative.[28] The overall goal of the program is to install 1,750 MW of photovoltaics statewide by 2016. Funding is divided among the investor-owned utilities in California on the basis of energy consumption. The SDG&E service area will receive funding over the program period that is expected to support 180 MW of new photovoltaic systems by 2016. After the California Solar Initiative is implemented, since it is likely that the amount of capacity installed will increase annually as photovoltaic prices fall, the project team calculated a wedge showing the GHG reductions associated with 400 MW of photovoltaics, which represents a significant increase over what is expected from the California Solar Initiative. This is higher than the level of photovoltaics that CARB assumes will be installed by 2020 in their Draft Scoping Plan.[29]

The emissions reduction resulting from 400 MW of photovoltaics is the smallest wedge, representing 0.2 MMT CO_2E. A portion of photovoltaic electric production occurs during peak, when the emissions rate is higher than the average emissions rate owing to use of lower efficiency resources. Emissions savings from installing this technology might be higher if this were taken into account.

3.8. Other Potential Wedges

The wedges above represent either existing law or policy directives or achievable savings using existing technologies. Other potential wedges exist that were not calculated as part of this analysis. Two areas in particular could offer further reductions. While nuclear energy raises many questions about storage of spent fuels, cost, and time to implement, it is generally an emissions-free method to generate electricity. The region already receives a significant amount of energy from the San Onofre Nuclear Generation Station (SONGS). Currently, California statute prohibits granting of new nuclear permits until a long-term storage solution is found.

Another possibility is carbon capture and storage from coal-fired generation. Carbon is injected into large underground or underwater cavities for long-term storage. With abundant coal supplies, such technology could help the United States meet future energy needs cleanly.

4. Electric Category Emissions Inventory Methodology

To determine GHG emissions from electricity generation in the San Diego region, the project team calculated the total amount of electricity needed in the region – including energy transmission and distribution losses and imported electricity – and used actual fuel data when available to calculate the associated GHG emissions. In some instances, no data were available to determine the fuel used to generate electricity. In those cases we used an estimated emissions rate (lbs/MWh) or developed a proxy based on similar fuel data. The following sections give more detail on each step of the process.

4.1. Energy Supply Data Sources

In general, the study relied on Federal Energy Regulatory Commission Form 1 to determine the region's overall energy supply and the eventual disposition of that supply, including data from the following sections of the form:

- **Purchased Power (Account 555):** SDG&E generates a portion of the electricity needed to supply regional needs using its own power plants. To supplement that, SDG&E purchases electricity from generation sources located in and out of the region. Account 555 includes, among other things, the entities from which SDG&E purchased energy and the amount purchased. These data were used to develop a detailed database of all SDG&E electricity suppliers. Between 1990 and 2006, SDG&E purchased electricity from more than 170 entities.

- **Electric Energy Account:** This account supplies data for total electricity sources and disposition for the year. Sources include the total generated, purchased, exchanged, and transmitted across the utility-owned transmission, as well as the losses incurred by others who wheel energy. Disposition includes sales to consumers, sales for resale, energy furnished without charge, energy used by the utility itself, and such other losses as those in transmission and distribution.

- **Steam-Electric Generating Plant Statistics (Large Plants):** This section of the FERC Form 1 supplies data on the total energy produced and fuel consumed by large power plants owned by SDG&E.

4.2. Determining Total Energy Supply

To determine the greenhouse gases associated with electricity generation, the team calculated total energy supplies for the region, the quantity of electricity needed by customers. It included electricity from SDG&E-owned generation assets, electricity purchased by SDG&E, electricity sold to customers who get electricity from a provider other than SDG&E (i.e., direct access), electricity associated with the California Department of Water Resources contracts issued during the 2000-2001 California electricity crisis, and on-site electricity generation used to offset customer load (self-serve). In addition to these sources, the calculation included transmission and distribution losses associated with all energy use.

The calculation was based on the following data sources, which were obtained from FERC Form 1 data unless otherwise noted:

- SDG&E Net Generation: the total amount of electricity generated by SDG&E-owned assets.

- Total Power Purchased: the total purchased by SDG&E to supplement its own generation.

- Sales for Resale: energy purchased and then resold, typically a negative number.

- Net Exchanges: contractual exchanges of electricity between two entities.

- Transmission Losses by Others: losses associated with electricity wheeled across the SDG&E's transmission system, counted as supply since they serve on-system demand.

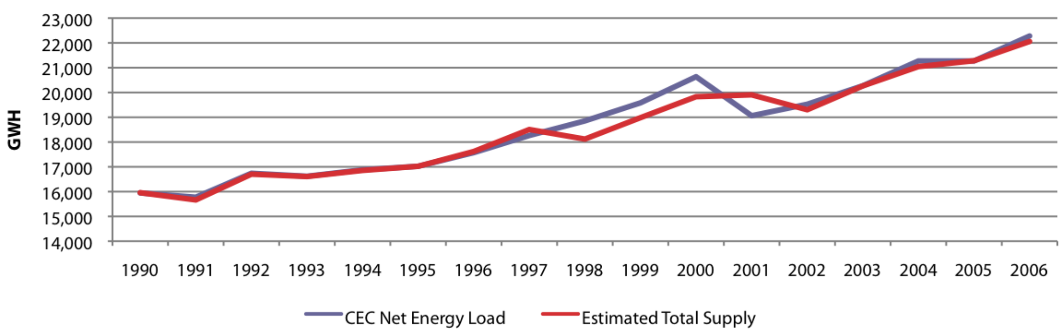
- Direct-Access Sales (Sempra Energy SEC Filings): electricity supplied to customers from suppliers other than SDG&E. Direct-access totals include transmission and distribution losses of approximately 7.5%.[30]

- Department of Water Resources Contracts: energy associated with DWR contracts assigned to the SDG&E territory. No public data were available, but energy totals were derived from EIA data. These also included transmission and distribution losses of 7.5%.[31]

- Self-Serve Energy (California Energy Commission): total energy generated on the customer's premises to serve on-site load was included in the energy supply total. Only nonphotovoltaic self-serve energy was included.

Since this project focused on San Diego County, the electricity associated with the small portion of Orange County that SDG&E serves, which was about 9% in 2006, was subtracted from the totals. Figure 12 compares the estimate of total energy supply developed by the project team with the latest forecast for net energy load from the California Energy Commission (CEC). The estimates matched up very well for all years except 1998-2001, which varied by up to 5% at times. This mismatch is likely attributable to data-reporting inconsistencies during the California electricity restructuring period and the energy crisis of 2000-2001. For the purposes of this study, the intermediate years are not as important as 1990 and 2006, both of which match up very well.

Figure 12. Total Electricity Supply for San Diego County



An estimate of the GHG emissions from each component part of the total supply was calculated. This helped to ensure that no double counting of energy values occurred. The method used to calculate emissions from each of these elements is discussed in detail below.

4.3. Emissions from SDG&E Net Generation

To calculate the total GHG emissions from SDG&E-owned generation assets, the project team used data from FERC Form 1 Electric Energy Account to determine the total amount of fuel combusted.
For this and all other calculations to estimate GHG emissions from electricity production, fuel data, heat content, CARB emissions factors for CO_2, CH_4, and N_20, and global warming potential (GWP) factors were used to calculate carbon dioxide equivalent. The basic equation for this calculation follows.
CO_2 Equivalent = [(Amount of fuel consumed) x (average heat content of fuel) x (CARB Emissions Factor – for CH_4, CO_2, and N_2O) x (GWP factor)]

Table 2 provides an example of this calculation for the Encina power plant in 1990.

Table 2. 1990 Encina Power Plant Emissions - Sample Calculation

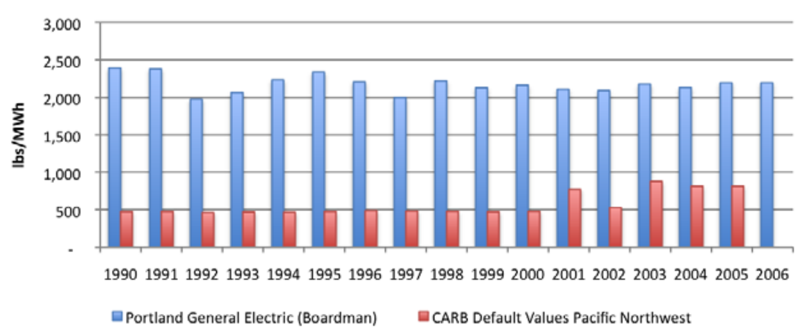
Fuel Type	Fuel Consumed	Average Heat Content (BTU/Unit)	Greenhouse Gas	CARB Emissions Factor (grams/BTU)	Global Warming Potential Factor	Total CO_2 Equivalent (grams)	Total CO2 Equivalent (MMT)
Natural Gas (mcf)	15,524,550	1,035,000	CH_4	0.000001	21	337,426,094	0.0003
Natural Gas (mcf)	15,524,550	1,035,000	CO_2	0.053		851,599,190,250	0.85
Natural Gas (mcf)	15,524,550	1,035,000	N_2O	0.0000001	310	498,105,187	0.0005
Distillate Fuel Oil (bbl)	700,969	6,203,694	CH_4	0.000003	21	273,961,622	0.0003
Distillate Fuel Oil (bbl)	700,969	6,203,694	CO_2	0.073		317,882,453,820	0.32
Distillate Fuel Oil (bbl)	700,969	6,203,694	N_2O	0.0000006	310	808,839,075	0.0008
Total						**1,171,399,976,049**	**1.2**

4.4. Total Purchased Power

SDG&E purchases a significant portion of electricity each year to supplement the amount they generate; therefore, this is an important component of the inventory. We used FERC Form 1 Purchased Power (Account 555) data from 1990 through 2007 to identify all entities that sold energy to SDG&E. These data were used to create a database that enabled us to see how much each supplier sold to SDG&E each year and to identify which suppliers sold the most electricity to SDG&E over the period studied.

The project team categorized each supplier by fuel and region. For region, we indicated if the information was available, whether the energy producer was located in the Pacific Northwest (PNW); Pacific Southwest (PSW); San Diego County; California; or an unspecified location. For fuel source, we used the following categories: unspecified, natural gas, coal, nuclear, digester gas, landfill gas, biomass, wind, and hydro. To be consistent with the method used by CARB and to account for transmission and distribution losses, we added a 7.5% loss factor to purchases that we knew originated outside the region. Because this project focused on San Diego County, energy use associated with Orange County demand (approximately 9%) was omitted.

Figure 13. GHG Emissions Boardman Plant (#8 - 4.3%)



Estimates of emissions from purchased electricity were derived by multiplying the total energy purchased by an emissions factor (lbs/MWh). Three different methods were used to calculate emissions levels, depending on the level of information available about the supplier and power plant: calculations based on actual fuel data, calculations based on default CARB multiplier, or calculations based on an average emissions profile of the entity selling power to SDG&E.

In the case of known locations and fuels, such as the Boardman coal-fired plant owned by Portland General Electric in Oregon, we knew the fuel and amount of energy sold, so we could use actual fuel and heat content data from EIA to calculate emissions levels for each year SDG&E purchased electricity from this power plant. Figure 13 shows the results of calculations to determine historical emissions rates from the Boardman plant and compares them to the default emissions factors developed by CARB for unspecified electricity purchased from the Pacific Northwest. Had we used the CARB default value for the energy associated with the Boardman plant instead of the actual emissions, the results would have underestimated the emissions. Portland General's Boardman plant was the eighth-largest supplier, producing 4.3% of the power purchased by SDG&E, during this period.

In cases where we did not have complete information about the location and fuel, we multiplied the energy values (MWh) by CARB emissions rates (lbs/MWh) for each category:

- Unspecified Geography/Unspecified Fuel: CARB value of 1,100 lbs/MWh.
- PNW, unspecified fuel: CARB default value for PNW for each year.
- PSW, unspecified fuel: CARB default value for PSW for each year.

In the third method, we calculated average emissions profiles for the utilities that sold the most electricity to SDG&E over the period 1990-2007. For six of the top known suppliers, we developed an average emissions rate (lbs/MWh) with actual fuel, heat content, and net energy generation numbers: PacifiCorp, Public Service Company of New Mexico, Salt River Project, Portland General Electric, Arizona Public Service, and Tucson Electric Power Company. Combined, these utilities supplied 26% of SDG&E's total purchased power between 1990 and 2007. Figures 14-18 show the average GHG emissions rate for each utility compared to the otherwise applicable CARB default rate. The figure title is followed by the rank of the supplier and the percent of purchased power supplied during this period.

Figure 14. Average GHG Emissions for PacifiCorp (#3 - 7%)[33]

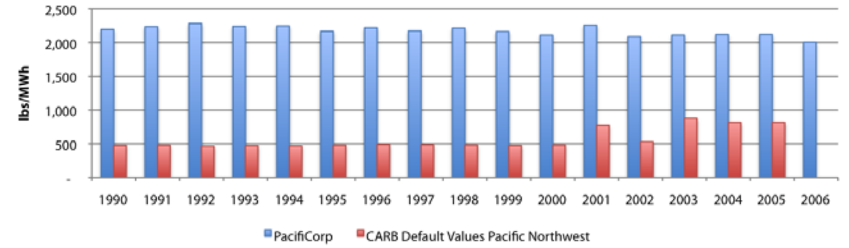


Figure 15. Average GHG Emissions For Public Service of New Mexico (#5 - 5.8%)

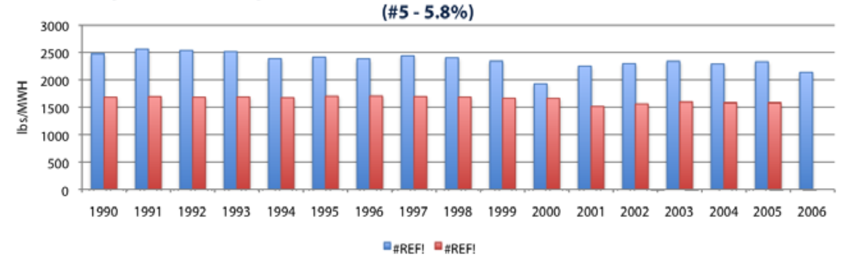


Figure 16. Average GHG Emissions For Salt River Project (#7 - 4.5%)

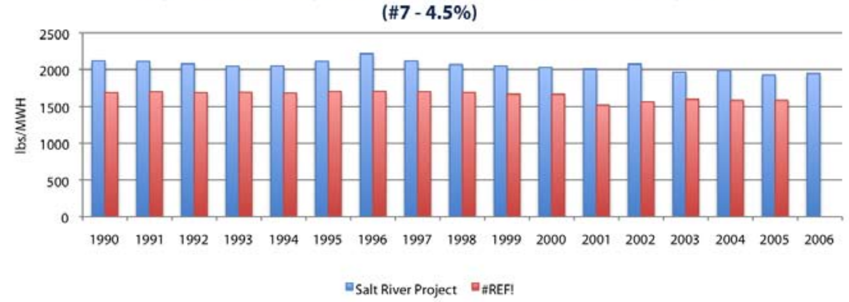
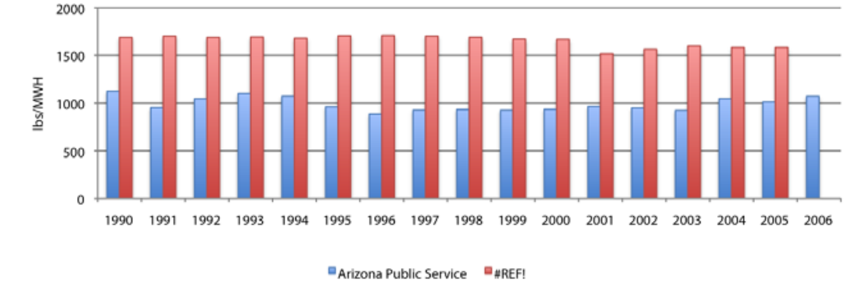
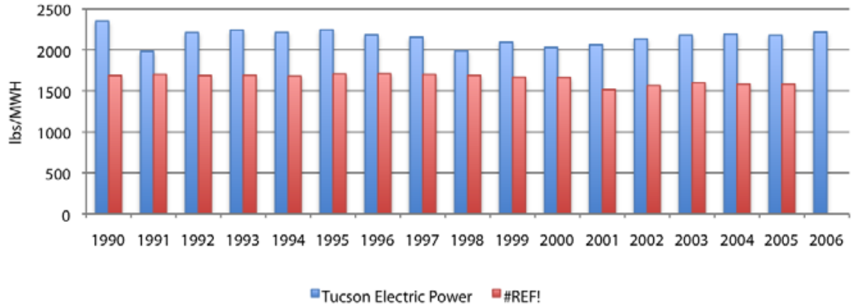


Figure 17. Average GHG Emissions for Arizona Public Service (#9 - 3.2%)



The CEC has recommended a method to account for emissions from imports using a dispatch approach, assuming a utility supplier would use its inexpensive energy (coal and nuclear) to satisfy its own needs and sell higher cost energy (natural gas) to others.[32] In the case of Pacificorp, whose actual emissions were significantly higher than the default CARB value, the energy generation portfolio was dominated by coal and there was little natural gas to sell. In the case of the suppliers from the Pacific Southwest, the difference in emissions rates was not significant – in the case of Arizona Public Service the composite emissions rate was lower than the CARB default value – and their overall contribution to total energy supplies was relatively small.

Figure 18. Average GHG Emissions for Tucson Electric (#18 - 1.5%)



4.5. Cogeneration

Taken together, all cogeneration purchases make up the largest energy supplier over the 17-year period. We knew the location of several cogeneration suppliers outside the region, such as Yuma Cogeneration Associates. We used actual fuel data for these to calculate GHG emissions levels. We made the simplifying assumption that all other cogeneration was located in the region.

While we had data on fuel use for some of the cogeneration plants located in the region, the FERC Form 1 data only provide an aggregated energy number. To determine GHG emissions, we multiplied this by a representative emissions rate (lbs/MWh) calculated using actual fuel and energy data for a sample of cogeneration systems.

For purposes of calculating total GHG emissions from electricity, only emissions associated with electrical production were assigned to the electricity category. To split out the thermal portion, we used the results of analysis of actual data by E3 that showed 63% of emissions attributable to electricity and 37% to thermal generation.[34] The emissions associated with the thermal portion of cogeneration are assigned to the "Other Fuels/Other" category in the charts included in the Executive Summary of the San Diego County Greenhouse Gas Inventory.

4.6. Other FERC Form 1 Categories

We included several other categories of FERC Form 1 data in our calculations, as follows:

- Sales for Resale: we calculated the emissions using average overall SDG&E emissions rate (lbs/MWh) for each year and then subtracted it from the total emissions for the region.

- Net Exchanges: we used average overall SDG&E emissions rate (lbs/MWh) for each year and then added/subtracted it from the total emissions for the region, depending on whether net exchanges were positive or negative.

- Transmission Losses by Others: we used average overall SDG&E emissions rate (lbs/MWh) for each year and then added it to the total emissions for the region. There were only "losses by others" in 1990 and 1992, and their emissions contribution to the total was minimal.

4.7. Direct-Access Sales

Data for direct-access sales were derived from Sempra Energy SEC Form 10-k, Table 5, for 1990-2006.[35] Consistent with CARB's method, we added a 7.5% transmission and distribution loss factor to this energy.[36] Since no public data are available on the amounts and sources of specific transactions, we calculated emissions using the default CARB rate of 1,100 lbs/MWh.

4.8. Department of Water Resources Contracts

No historical data were available for the actual quantity of energy purchased as a result of ongoing Department of Water Resources contracts. We estimated energy levels by using FERC Form 1 Purchased Power data and EIA wholesale purchase data from Form 861.[37]

For several years, the FERC Form 1 data on purchased power varied significantly from the EIA Form 861 data for wholesale purchases. The difference was assumed to be the Department of Water Resources Contracts, as shown in Table 3.

Table 3. Estimated Department of Water Resources Totals

Data Source	2001	2002	2003	2004	2005	2006
Wholesale Purchases EIA Form 861	13,568,541	10,935,412	12,075,204	13,109,328	12,856,203	12,424,852
Purchased Power FERC FORM 1	6,549,941	3,823,022	7,079,998	5,471,401	5,015,197	5,086,291
Difference	7,018,600	7,112,390	4,995,206	7,637,927	7,841,006	7,338,561

Data were available for estimated energy from the DWR contracts in the future. SDG&E's long-term procurement plan includes an energy-balance estimate that forecasts energy associated with the DWR contracts.[38] We used these data to develop approximate energy supplies from each contract. We added transmission and distribution losses of 7.5% to those sources we knew originated outside the region.

For the largest contract, Sunrise, we estimated energy purchased and then used EIA fuel, heat content, and net energy generation data to develop an emissions rate (lbs/MWh). We multiplied that by the estimated energy supply from the plant. The second-largest contract was the Williams B contract; here, we used the CARB unspecified default value of 1,100 lbs/MWh.

4.9. Business as Usual Electricity and Greenhouse Gas Emissions Projections

As mentioned above, our total energy supply calculation matched the CEC calculation very well for most of the 1990-2006 period. To project into the future, we chose to use the CEC demand forecast data for 2008-2018. We used a linear projection of the CEC estimate for net energy load until 2020. To capture all the energy uses that create GHG emissions, we added total private supply (self serve). This became the basis for calculating the business-as-usual GHG emissions projections.

The CEC forecast incorporates the effects of the 2005 building standards and currently funded energy efficiency programs through 2008.[39] This is particularly relevant to the wedge that reduces electricity consumption by 10%.

4.10. Limitations of the Methods

In general, the methods used to estimate total GHG emissions for the electricity sector could be improved by access to more relevant data, particularly fuel and DWR Contract energy data. In many cases, fuel data were available, but in the cases of much of the electricity purchased by SDG&E to supply the region, the California Department of Water Resources contracts, and all of the energy associated with direct access, no data exist on the actual source of the electricity. Thus no data are available on the amount of fuel used. The total electricity supplied from these sources was approximately 30% of total energy supplies to the region: 11% from purchased power, 17% from direct access, and a fraction from unspecified DWR contracts. To overcome this data gap, CARB, the CEC, and the CPUC have developed default emissions factors for energy originating in the Pacific Northwest, Pacific Southwest, and from unknown origins. In at least one case shown here, use of the default factor resulted in significant underestimation of emissions.

Where possible, the project team used actual data, but in cases where data were not available, we used CARB default emissions rates (e.g., for unspecified electricity imports) or we developed a proxy rate based on actual data. For example, between 1990 and 2006 about 45% of the GHG emissions estimate associated with purchased power was derived using CARB default emissions values, 30% was derived using actual fuel consumption data, and about 15% was calculated using a proxy emissions rate developed with actual fuel consumption data. By definition, this introduces some uncertainty into the estimate.

As indicated above, we developed an estimate for the total annual energy associated with the DWR contracts. We used several data sets to develop the estimate, but to estimate emissions more accurately, actual fuel and energy generation data would be necessary.

End Notes

1. Business-as-usual emissions projections for the electricity sector exclude additions of renewable energy (to comply with the Renewable Portfolio Standard) above 2007 levels (6% of retail sales).
2. These totals are for renewable energy additions above 2007 levels (6% of retail sales).
3. This breakdown was included in the electricity data provided by the California Energy Commission.
4. This assumes that all renewable energy has no emissions.
5. Business-as-usual emissions projections are based on the California Energy Commission (CEC) Energy Demand Forecast for 2008-2018 (see California Energy Demand 2008-2018 Staff Revised Forecast. CEC November 2007, available at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF [last viewed 6-17-08]) and exclude additions of renewable energy to comply with the Renewable Portfolio Standard above the levels achieved in 2007 (6%).
6. The project team recognized that there could be complex interactions between and among categories (such as increased electricity use to offset traditional transportation fuels) but did not determine the effects of these interactions. To the extent that these are captured in the CEC forecasts, they are captured here.
7. For purposes of this analysis, we assumed that renewable energy has no emissions.
8. S. Pacala and R. Socolow, Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies. Science, 13 August 2004, Vol 305, pp. 968-972.
9. California Energy Commission, Energy Action Plan: 2008 Update, February 2008. Available at http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.
10. Cal. Pub. Util. Code § 399.11 et seq.
11. California Public Utilities Commission, Progress Towards 20% by 2010, http://www.cpuc.ca.gov/PUC/ energy/electric/RenewableEnergy/progress.htm
12. On the basis of RPS compliance filings made on August 1, 2007, California's three large IOUs collectively served 13.2% of their 2006 retail electricity sales with renewable power. See the PUC report referenced above.
13. For simplicity, we assumed that renewable energy has no emissions.
14. 2007 Integrated Energy Policy Report, Commission Final Report, adopted December 5, 2007. Publication CEC-100-2007-008-CMF. Available at http://www.energy.ca.gov/2007_energypolicy/index.html.
15. SB 411. http://leginfo.ca.gov/pub/07-08/bill/sen/sb_0401-0450/sb_411_bill_20070717_amended_asm_v97.html
16. California Energy Commission, Energy Action Plan: 2008 Update, February 2008. Available at http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.
17. These include SDG&E, the Gas Company, Southern California Edison, and Pacific Gas & Electric. Other municipal utilities, such as the Los Angeles Department of Water and Power, also have similar energy programs but are not regulated by the Public Utilities Commission.
18. Itron, Inc., California Energy Efficiency Potential Study (draft final). Pages 4-45, May 12, 2007. Available at http://www.calmac.org/publications/PG&E_EE_FcstModelReport_DraftFinal.pdf (last viewed June 3, 2008). See also http://www.calmac.org/NewPubs.asp.
19. Projected energy supply is based on the CEC forecast, which incorporates the effects of the 2005 building standards and currently funded energy efficiency programs through 2008.. See California Energy Demand 2008-2018 Staff Revised Forecast. CEC, November 2007. Available at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF (last viewed June 17, 2008).
20. See Decision 07-10-032 in Rulemaking R.06-04-010 at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/74107.pdf. AB 2030 seeks to develop standards for nonresidential buildings. AB 2112 seeks to develop standard for residential buildings.
21. AB 2030 seeks to develop standards for nonresidential buildings. AB 2112 seeks to develop standard for residential buildings.
22. See the CEC Appliance Standard Rulemaking 2008 (Docket #070-AAER-3) available at http://www.energy.ca.gov/appliances/2008rulemaking/
23. California Air Resources Board, Climate Change Draft Scoping Plan a Framework for Change. June 2008.

24. Form 10-K for SDG&E, U.S. Securities and Exchange Commission. Filed December 31, 2007.
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26. Assessment of California CHP Market and Policy Options for Increased Penetration, EPRI, Palo Alto, CA, and California Energy Commission, Sacramento, CA, 2005.
27. Energy and Environmental Economics, Inc., Modeling Inputs for New CHP Built in 2008 and 2020. Go to http://www.ethree.com/GHG/New%20CHP%20Data.032408.xls.
28. Decision 06-12-033, Rulemaking 06-03-004, 12/18/2006. Available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/63031.pdf (last viewed June 3, 2008).
29. California Air Resources Board, Climate Change Draft Scoping Plan a Framework for Change. June 2008.
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31. Ibid.
32. A. Alvarado and K. Griffin, Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports: Update to the May 2006 Staff Report. March 2007, California Energy Commission.
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34. CHP in the E3 GHG Model: Proposed Changes for Stage 2. Presented to the California Public Utilities Commission on April 1, 2008, by Energy and Environmental Economics, Inc. (E3).
35. http://www.shareholder.com/sre/edgar2.cfm