Cost-Benefit Analysis of the Self-Generation Incentive Program

DRAFT CONSULTANT REPORT

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California Energy Commission

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October 2008
CEC-300-2008-010-D

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ABSTRACT

TIAX has developed a methodology to determine the cost and benefit elements of the Self Generation Incentive Program. The impacts evaluated were broadly categorized as environmental impacts, macroeconomic impacts, and grid impacts. The analysis considered all installations interconnected before December 31, 2006, which amounted to 1062 installations with a cumulative capacity of 263.1 MW. In each case, a 30 year lifetime was assumed. There are six technologies that were eligible for SGIP funding during the installation timeframe considered: photovoltaic systems (now administered as part of the California Solar Initiative), internal combustion engines, microturbines, fuel cells, small gas turbines, and wind turbines. The combustion, turbine, and fuel cell technologies are distinguished further by fuel type: non-renewable or renewable. The TIAX analysis also separated technologies by the major investor owned utilities that administer the incentive payments of the SGIP: Pacific Gas and Electric, Southern California Edison, Southern California Gas, and San Diego Gas and Electric.

Keywords: Self Generation Incentive Program, distributed generation, cost-benefit analysis, combined heat and power, transmission and distribution, green house gases, climate change, air quality, renewable fuels, California economy.

EXECUTIVE SUMMARY

Background

Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000) directed the California Public Utilities Commission (CPUC) to adopt initiatives to reduce electricity demand, including incentives for distributed generation technologies. The CPUC created the Self-Generation Incentive Program to promote eligible distributed generation technologies under 5 megawatts (MW) to meet all or a portion of customers' electricity needs.[1] The Self-Generation Incentive Program is one of the largest distributed generation incentive programs in the United States, with approximately 1,200 projects totaling 300 MW on-line by the end of 2007. The total capacity is fairly evenly divided between cogeneration and solar photovoltaic projects.[2]

From 2001 through 2004, funding for the Self-Generation Incentive Program was set at $125 million per year, which was collected through a surcharge on electricity and natural gas bills.[3] Rebates from the Self-Generation Incentive Program are available to electric and/or gas customers of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company, and San Diego Gas & Electric (SDG&E).

Assembly Bill 2778 (Lieber, Statutes of 2006, Chapter 617) then extended the Self Generation Incentive Program to January 1, 2012, and required the Energy Commission, in consultation with the CPUC and the California Air Resources Board (ARB), to evaluate the CPUC's Self-Generation Incentive Program and the costs and benefits of expanding eligibility for the program to renewable and fossil fuel "ultraclean and low-emission distributed generation." The Energy Commission contracted with TIAX LLC to evaluate the Self-Generation Incentive Program.

Analysis

TIAX and its team of subcontractors developed a clear methodology to determine the costs and benefit elements of the Self-Generation Incentive Program. A broader scope than normal was used to evaluate demand-side programs and categorized as environmental impacts, macroeconomic impacts and grid impacts. Where possible, the

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1 For more information on the early implementation of the Self-Generation Incentive Program, see CPUC Decision D.01-03-073.

2 http://www.cpuc.ca.gov/PUC/energy/sgip/051005_sgip.htm

3 CPUC, Decision 01-03-073, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/6083.PDF, p. 7, 11-13, and 49-50.

impacts were also quantified to compare the costs and benefits to the participant, non-participant (for example, the ratepayer) and society.

The cost-benefit analysis considered 1,062 installations (263.1 MW of installed capacity) interconnected from 2002 through 2006. TIAX considered the six (6) technologies that were eligible for the Self-Generation Incentive Program funding during this timeframe: photovoltaic system, internal combustion engines, microturbines, fuels cells, small gas turbines and wind turbines. The combustion turbine and the fuel cell technologies are further categorized by fuel type: non-renewable or renewable. The analysis also separated technologies by the major investor-owned that administered the program incentive payments. The technologies were evaluated over approximately a 30-year lifetime.

Results

The environmental analysis of the Self-Generation Incentive Program focused on the emissions of air quality pollutants and greenhouse gases (GHGs) that cause climate change. The emissions of distributed generation technologies were compared to marginal power generation, defined in this report as a natural gas fired combined cycle combustion turbine power plant. The analysis indicated that renewable energy technologies or renewable fueled distributed generation technologies yielded a reduction in both air quality pollutants and GHGs. The Self-Generation Incentive Program installations yielded a net reduction in both particulate matter (PM2.5) and GHGs. However, the reductions are small and largely attributable to photovoltaic installations which are no longer eligible for the program. Furthermore, the program's installations have net emissions of air quality pollutants including volatile organic compounds (VOC), nitrogen oxides (NO_x), and carbon monoxide (CO). Although the installed capacity of the Self-Generation Incentive Program is small, the environmental benefits do indicate that engine and turbine technologies operating with a clean or renewable fuel, particularly those in efficient combined heat and power applications can reduce air quality pollutants and GHGs.

The macroeconomic impact analysis considered the gross benefits of the Self-Generation Incentive Program expenditures in California, and compared these impacts to equivalent household expenditures. The analysis was performed using an input-output model called Impact Analysis for Planning (IMPLAN). The output of the model indicates that the Self-Generation Incentive Program yields significant added value to the California economy, including significant impact on employment. The analysis also indicates that when compared to the same level of household expenditures, the incentives of the program yield slightly higher output in California, and higher levels of compensation per full time equivalent worker; however, household expenditures do yield more full time equivalent worker hours.

The analysis to identify grid impacts on the Transmission and Distribution system used a unique 9-step process. This process identified the potential energy commodity savings and distribution deferral potential of the Self-Generation Incentive Program installations in detail using GE's Multi-Area Production Simulation™ software. The grid impacts analysis focused on avoided energy costs, transmission and congestion savings, and potential electric distribution system savings. The analysis demonstrated that the Self-Generation Incentive Program, even without targeting the investments, did yield distribution deferral savings; however, the percentage of installations capable of deferring distribution investments could be increased significantly with a more targeted approach. Similarly, the modeling analysis demonstrated the prevalence of spatial price dispersion, with a virtually ubiquitous price differential of $15-20 per MWh.

Conclusions and Recommendations

Currently, the restricted eligible Self-Generation Incentive Program technologies have resulted in few if any distributed generation installations. TIAX recommends re-instating the eligibility of internal combustion engines, microturbines, and small gas turbines with requirements that these technologies use super clean and renewable fuel use and that they are used in efficient combined heat and power applications. Further analysis indicates that the grid impacts of distributed generation installations are location-dependent. This result suggests that the program incentives could yield significantly higher benefits to the non-participant and society if investments are targeted using a new investment strategy that would have to be worked out with the utilities as it will involve distribution planning and engineering staff.

Finally, TIAX recommends that the goals and objectives of the Self-Generation Incentive Program be revisited to ensure that they are in line with the State's energy goals and broader policy objectives. A clarification of the Self-Generation Incentive Program goals and objectives will ensure that the California Public Utilities Commission and Energy Commission are working in concert with the IOUs to maximize the benefits of distributed generation resources for both ratepayers and program participants.

CHAPTER 1: Introduction

The scope of this work is defined as a cost-benefit analysis of the Self-Generation Incentive Program (SGIP) based on generators installed through the end of 2006. The Standard Practice Manual (SPM, (CPUC/CEC 2001)) developed by the California Energy Commission and the California Public Utilities Commission (CPUC) provides useful guidance in the evaluation of the cost-effectiveness of demand-side management programs using tests from varying perspectives (e.g., participant, non-participant, and total resource cost test). The work presented in this report is focuses on a societal perspective; however, as a result of feedback from the September 3, 2008 Staff Workshop, where possible, costs and benefits of the SGIP are allocated based on a participant and non-participant basis. In addition to the societal basis, the scope of this report includes the foundation of an adaptable cost-benefit analysis methodology that is in line with the SPM, reflective of market realities, and can serve as the foundation to evaluate the costs and benefits of other demand-side programs.

Background of the SGIP

This section discusses a review of the objectives of the SGIP and a brief review of the program's history to date.

Review of the SGIP Objectives

The SGIP was established as directed by Assembly Bill 970 (AB 970) and the CPUC issued Decision 01-03-073 in March 27, 2001 to implement this program. The program was structured to fulfill the requirements which called for "incentives for distributed generation to be paid for enhancing reliability" and "differential incentives for renewable or super clean distributed generation resources." In addition to these directives[4], the program outlined the following objectives:

- Use an existing network of service providers and customers to provide access to self-generation technologies quickly
- Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just individual consumers
- Help support continuing market development of the energy services industry
- Provide access through existing infrastructure, administered by the entities with direct connections to and trust of small consumers
- Take advantage of customers' heightened awareness of electricity reliability and cost.

Apart from the objectives, the decision also highlights that the incentives paid through the SGIP are intended to:

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[4] Public Utilities Code 399.15(b), paragraphs 6 and 7

- Encourage the deployment of distributed generation in California to reduce the peak electric demand;
- Give preference to new renewable energy capacity; and,
- Ensure deployment of clean self-generation technologies having low and zero operational emissions.

The stated objectives and intentions of the SGIP are important to keep in mind throughout the cost-benefit analysis. These will be revisited as necessary throughout the report, and in particular in Chapter 5: Conclusions and Recommendations.

History of the SGIP

The SGIP is currently the largest distributed generation (DG) incentive program in the nation. Under the provisions outlined by CPUC, a variety of DG technologies received rebates based on installed capacity and incentive level. The incentive level is determined by technology and fuel type of the installed generator. The eligible generation technologies through 2006 and considered in this report include: photovoltaics (PV), internal combustion engines (ICEs), microturbines (MTs), fuel cells (FCs), gas turbines (GTs), and wind turbines (WD). The incentives for DG technologies that rely on fuel (i.e., all except PV and WD) were further distinguished by the use of renewable (-R) and non-renewable (-NR) fuel.

The SGIP incentives are available to customers in the service territories of all three major investor-owned utilities (IOUs) in California as well as many local municipal electric utilities. There are Program Administrators at Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas (SCG), and the California Center for Sustainable Energy (CCSE). The PA at CCSE oversees the SGIP installations in the San Diego Gas and Electric (SDGE) service area.

For a more detailed description of the SGIP, see the CPUC SGIP Sixth Year Impact Evaluation prepared by Itron, Inc. (Itron August 2007).

SGIP: Through December 31, 2006

This report examines the costs and benefits of DG installations that came online before December 31, 2006. In some cases, incentives for these systems were paid after that date; however, the only criterion for inclusion in this report is an interconnect date prior to December 31, 2006. The number of installations and the corresponding installed capacity, distinguished by utility and technology are shown in Table 1.

Table 1. SGIP Installed Capacity and Installations through 12/31/2006

	PG&E		SCE		SCG		SDGE		total	
	n	capacity	n	capacity	n	capacity	n	capacity	n	capacity
PV	366	51.9	183	21.5	77	10.8	93	12.6	718	96.0
ICE-NR	81	47.5	41	21.8	54	40.5	17	9.2	193	119.0
ICE-R	7	3.9	2	1.5	1	1.0	--	--	10	6.5
MT-NR	38	6.4	24	3.8	28	4.8	12	1.1	102	16.0
MT-R	12	1.8	4	1.0	--	--	3	0.6	19	3.4
FC-NR	6	3.6	1	0.2	2	1.5	2	1.5	11	6.8
FC-R	--	--	2	0.8	--	--	--	--	2	0.8
GT-NR	3	4.0	--	--	1	4.5	1	4.5	5	13.0
WD	--	--	2	1.6	--	--	--	--	2	1.6
totals	513	119.0	258	51.5	163	63.0	128	29.5	1062	263.1

PV=photovoltaic; ICE=internal combustion engine, MT=microturbine, FC=fuel cell; GT=gas turbine, WD=wind turbine. –NR=non-renewable fuel, -R=renewable fuel

Structure of Report

In Chapter 2, the methodology and approach is described in considerable detail, with focus on the three types of impacts evaluated in this report: environmental impacts, macroeconomic impacts, and grid impacts. Chapter 3 presents results from each of the three areas outlined in Chapter 2. Also included in Chapter 3 is a review of the monetized impacts from varying perspectives i.e., Participant, Non-participant, and Societal perspectives. Chapter 4 briefly reviews technologies that were eligible for the SGIP and considers their eligibility, as well as outlines a handful of technologies that may be SGIP-eligible in the future. Chapter 5 concludes the report with recommendations for the SGIP based on the results.

CHAPTER 2: Methodology and Approach

Cost-Benefit Analysis

Traditionally, cost-benefit analyses are conducted prior to initiating public programs to determine the economic value of the program and its alternatives. In principle, a cost-benefit analysis will determine if a program qualifies on cost-benefit grounds based on the present value of benefits compared to the present value of costs. The cost-benefit analysis serves as an appraisal technique for public investments and public policy. In the case of the SGIP, however, the program is actively paying incentives for DG installations and has been doing so since 2001. As such, the cost-benefit analysis outlined in this report is slightly different because it is partly a review of the program through the year 2006, and partly a projection of the program into the future. The goal then, is to determine the benefits and costs of the program based on the interconnect criteria (all installations before December 31, 2006), rather than determine whether the program qualifies on a cost-benefit grounds (i.e., benefits > costs). The primary objective of this report is to develop a sound and robust methodology for a cost-benefit analysis of the SGIP. A sound cost-benefit analysis methodology will help shape the SGIP moving forward and ensure the program is in line with the State's energy policy goals and is providing net benefits.

The characteristics of the cost-benefit analysis are defined by a series of logical steps. The first step has already been completed: identify the policy or project to be evaluated. Secondly, the cost-benefit analysis must determine standing, in other words, whose costs and benefits are counted. This is the same question of perspective that is discussed elsewhere in this report. In the case of the SGIP, there are a number of groups with standing: the participant who installs a generator, the non-participant (i.e., the ratepayer without DG), and society. To the extent possible, the costs and benefits to each of the aforementioned groups, the participant, non-participant, and society will be considered in this report; however, the primary focus of standing is on society.

Having identified the program and determined standing, the benefits and costs are considered. There are two steps related to the benefits and costs. Firstly, the benefits and costs under consideration must be identified (see Chapter 2, Costs and Benefits). Throughout the course of this analysis, TIAX has taken care to ensure that the major elements in both categories are included and that double counting is avoided. Secondly, an approach must be outlined to determine the value of the identified benefit and cost elements (see Chapter 2 subsections). Many of the costs and benefits in the program are straightforward. For instance, the administration costs and installed equipment costs are reported, documented, and readily available. Some benefit elements of the incentive program are more difficult to value (i.e., monetize). For instance, the environmental benefits of self generation installations are a function of technical performance, the determination of a baseline generation technology for comparative purposes, and the monetized value of an environmental pollutant. None of the listed variables are trivial to determine.

The time horizon of valuing the benefits and costs must be given due consideration, as individuals have preferences for when benefits are received and costs are imposed. The time horizon is addressed by discounting, discussed in greater detail below.

It is important to note that benefits and costs are difficult to determine with a high degree of certainty. However, because this report evaluated an existing program with a significant amount of data available, there is a unique opportunity to narrow uncertainties and risk (i.e., probabilistic outcomes) in the evaluation of the SGIP moving forward or similar incentive programs.

Data and Data Sources

Program Administrators and the SGIP Working Group

The Program Administrators for the SGIP provided basic data on the SGIP facilities, including installed costs, technology type, type of fuel used (as appropriate) installed capacity, and address of facility. In addition to the total eligible installed costs, the Program Administrators provided a sample of Project Cost Breakdown Worksheets. These worksheets were submitted as hard copies with the project application to help the PA distinguish between eligible and ineligible program costs (see SGIP Handbook for more information, (SGIP 2008)). Jack Faucett Associates (JFA), a TIAX subcontractor used the breakdown of costs to allocate the costs in the California Input-Output (I-O) economic model. For a more detailed description of the I-O model and JFA's approach, see Chapter 2.

In addition to these basic facility data, the IOUs and Program Administrators provided a subset of interconnection data, including the name of the nearest substation, voltage of the utility interconnection line, maximum permissible line loading (in kVA), annual maximum recorded line loads (2001-2006), the transformer bank feeding the interconnection line, maximum possible bank loading (in kVA), and annual maximum recorded bank loads (2001-2006). These data were used by Rumla Inc. as part of their analysis of the transmission and distribution benefits of the SGIP. For a more detailed explanation of the approach to determine the costs and benefits, please see Chapter 2, Grid Impacts

Itron Inc.

Itron Inc. (Itron) has performed the metering and evaluation of the SGIP since 2002. Itron provided TIAX with 15-minute averaged metering data for the facilities monitored since 2002. These data include the following: electrical net generator output (ENGO), the fuel used by the facility (FUEL), and the waste heat captured by cogeneration systems (HEAT). These data are discussed in more detail in Chapter 2.

In addition to the metered data, the reports that Itron prepared provide a wealth of aggregated information on the SGIP, and these reports are cited as appropriate throughout this report.

California Public Utility Commission (CPUC) and Investor Owned Utilities (IOUs)

The CPUC and IOUs provided electricity tariff data, including time-of-use rates and demand charges. Forecasts of retail prices for both gas and electricity rely on current tariffs as a starting point. Retail electricity and natural gas prices were escalated based on forecasts by the Energy Information Administration's (EIA) Annual Energy Outlook.[5] Retail gas rates were used to value both purchased generator input fuel and avoided purchases of natural gas resulting from recovered waste heat.

Costs and Benefits

According to the Department of Energy, "there are not standardized methods for reporting costs, benefits, and valuation of DG" (DOE August 2006). Both the Energy Commission and the CPUC have spent considerable time to identify the costs and benefits of distributed generation. In 2004, the costs and benefits of DG were identified as a priority issue for the CPUC through rulemaking R.04-03-017. The Energy Commission and the CPUC worked collaboratively on the issue and released a number of reports (Rawson July 2004; CPUC March 2005). The costs and benefits identified in this report are generally consistent with those identified by the collaborative staff; however, there are some differences that will be addressed here.

The TIAX team identified the costs and benefits of the SGIP listed in Table 2. Note that the cost and benefit elements are separated into the three core perspectives that will be considered in this report to the extent possible: Participant, Non-Participant, and Society. The focus, however, is on the Societal perspective.

Table 2. SGIP Costs and Benefits

Participant	Non-Participant	Society (California)
Benefits		
electric bill savings	**avoided energy costs**	***customer reliability benefits***
customer reliability benefits	energy commodity savings	***local reliability benefits***
fuel-for-heat savings	congestion charge savings	**societal environmental benefits**
SGIP incentives	transmission losses savings	**fuel-for-heat savings**
tax credits	avoided ancillary service charges	**avoided energy costs**
credits toward RPS	avoided CAISO charges	(avoided ancillary service charges)
	congestion reduction savings	(avoided CAISO charges)
	customer standby fees	congestion reduction savings
	distribution capital deferral savings	distribution capital deferral savings
	distribution loss savings	(distribution loss savings)
	local reliability benefits	(gas price moderation savings)
		economic impacts
Costs		
capital costs	lost revenues	fuel costs – operational
fuel costs – operational	administrative costs	O&M expenditures
O&M expenditures	**SGIP incentives**	administrative costs
standby charges		**capital cost**

[5] Forecasts were retrieved from the EIA's website at http://www.eia.doe.gov/.

The bolded items in Table 2 indicate the costs and benefits with the highest value, whereas those that are italicized indicate elements that will not be quantified in this report. For instance, customer reliability benefits are likely very high, however, quantifying the benefits and further monetizing them is beyond the scope of this report. Similarly, there are likely cases where installations of the SGIP offer local reliability benefits, however, the benefits are difficult to quantify. The benefit elements listed in parentheses under the Society column have low or very low (monetized) value. Estimating the gains for these elements is not difficult and the results will not significantly affect the SGIP design or implementation. With a focus on a Societal perspective of the SGIP, this report does not include tax credits or incentives beyond the SGIP incentives paid to participants.[6]

This report also does not consider standby charges incurred by DG installations. In many cases, the DG installations under the SGIP are exempt from standby charges, and this should be quantified as a cost component via lost revenues.

The DG installations of the SGIP may help the IOUs meet the targets laid out by the Renewable Portfolio Standard (RPS); however, at this time, the program is too small to make a sizeable impact towards these goals, and was not quantified here.

Of the benefits listed in Table 2, most are also identified in the previously referenced Energy Commission and CPUC documentation. There are several items that are not included and are discussed briefly here.

There are a variety of DG benefits and costs that are potentially high, however, the methodology to quantify and to monetize them subsequently is outside the scope of this report. For example, national security benefits via reduced security risk to the grid and NIMBY opposition to central power plants are examples of benefits that may have significant value, but are too difficult to quantify and/or monetize. On the cost side of the equation, noise disturbance is a similar example.

Discount Rates

Discount rates are a standard economic practice to account for the higher economic value of benefits accrued today rather than tomorrow. The selection of an appropriate discount rate for projects that have both private and public cost and benefit elements is particularly challenging. Perhaps it was stated best by Pearce *et al* (Pearce 2006) when they wrote that “few issues in cost-benefit analysis excite more controversy than the use of a discount rate.” In this report, TIAX stripped the benefits and costs of inflation and performed the analysis entirely in 2006 dollars where possible. The lifetime of the DG applications is assumed to be 30 years. Because of the approach in which all dollars were first normalized to 2006, only a real discount rate is required to account for the time value of money. The concept of the time value of money is based on the premise

[6] There are some installations that received incentive payments from the Energy Commission via another DG program. These incentives were not considered here and are unlikely to impact the results significantly. There are also state and federal tax credits and incentives for PV and wind powered generation, as well as renewable-fueled cogeneration systems. The federal tax credit is estimated in the discussion of Section 5, but not presented in detail. There are also depreciation benefits at the state and federal level that were not considered in this report.

that an investor prefers to receive a payment of a fixed amount of money today, rather than an equal amount in the future, all else being equal. This is largely because, if payment is received today, it is possible to invest and earn interest on the money until that specified future date.

The real discount rate used to discount costs was based on guidance in Appendix C of the Office of Management and Budget’s Circular No. A-94 (Revised January 2008) entitled “Discount Rates for Cost-Effectiveness, Lease Purchase, and Related Analyses (OMB October 1992). The Circular defines the real discount rates as “a forecast of real interest rates from which the inflation premium has been removed. These real rates are to be used for discounting constant-dollar flows, as is often required in cost-effectiveness analysis.” Circular No. A-94 lists the discount rate for periods of 30 years as 2.8 percent.

It is important to note that the emphasis of this report is on the methodology to determine the costs and benefits of the SGIP. The real discount rate is primarily used to determine the net present value of monetized costs and benefits. As such, the monetized impacts of the program may increase or decrease depending on the discount rate employed. In general, the private sector uses a higher discount rate for investments than the public sector (e.g., 7 percent).

Some researchers have noted that discounting “militates against solutions to long-run environmental problems: for example, climate change, biodiversity loss and nuclear waste, which need to be evaluated over a time horizon of several hundred years (Groom 2005).” Furthermore, one can argue that exponentially discounting benefits in the future is in contrast to sustainability, which is characterized by principles of intergenerational equity and implies that policies should contribute to sustained increases in welfare for future generations. In response to the problem of standard discount rates, some researchers have advocated the utility of a declining discount rate which declines with time, according to a defined function. As a result the value of benefits to future generations is increased compared to standard methods of discounting. TIAX opted not to employ a declining discount rate for two reasons: 1) the time-horizon considered in this analysis is too short (30 years) and 2) the declining discount rate is best used in the determination (or calculation) of the social costs (or damage costs) of pollutants. The report here employs a benefits transfer methodology, rather than performing original calculations of damage costs.

Technological Performance Data

TIAX evaluated the technical performance of 1) PV installations and 2) non-PV installations. The installations were separated into these two categories based on similar characteristics and simplifying assumptions. For instance, the performance of PV technologies is dependent on location, weather, orientation, and time-of-day. On the other hand, the performance of non-PV technologies (with the exception of wind, of which a very small sample of metered data were available), are independent of location. The generation profiles of these technologies are more site-specific and are driven by the participants' needs; however, on average, the efficiency and capacity factors are similar.

PV System Performance Data

PV system performance is a function of system configuration, time of day, weather, and solar radiation. In the event that no metered data were available for a given installation, data were estimated based on metered data for PV installations in the same zip code, and adjusted based on system orientation where appropriate. In the event that no metering data for the zip code existed, metered data from zip codes with identical first 3 digits were used.[7] In the rare case that data were still not available at that level, an average of metered data for the entire IOU was used.

TIAX recognizes that there are potential uncertainties introduced when PV performance is based on data aggregated at the zip code or SCF level. To estimate the uncertainty of the approach employed here, TIAX identified installations with metered data and estimated their performance based on the criteria described above. In some cases, the estimated and actual performance differed by as much as 50 percent. In general, however, TIAX estimates that the uncertainty of the approach used here to estimate PV system performance is 30 percent. Note that the estimated generator output of installations operating between 2002 and 2006 represents 55 percent of the sum of estimated and metered output. So, although the approach used in this analysis has an uncertainty up to 30 percent, this only accounts for an uncertainty of some 17 percent for the total PV generator output.

Non-PV System Performance Data

The methodology used to estimate the lifetime performance for non-PV technologies – ICEs, MTs, FCs, GTs and WD – is similar. Figure 1 shows the installed capacity from 2002-2006 for all non-PV technologies.

[7] The first 3 digits of zipcodes identify the sectional center facility (SCF) for the post office.

Figure 1. Installed Capacity from 2002-06 for non-PV technologies

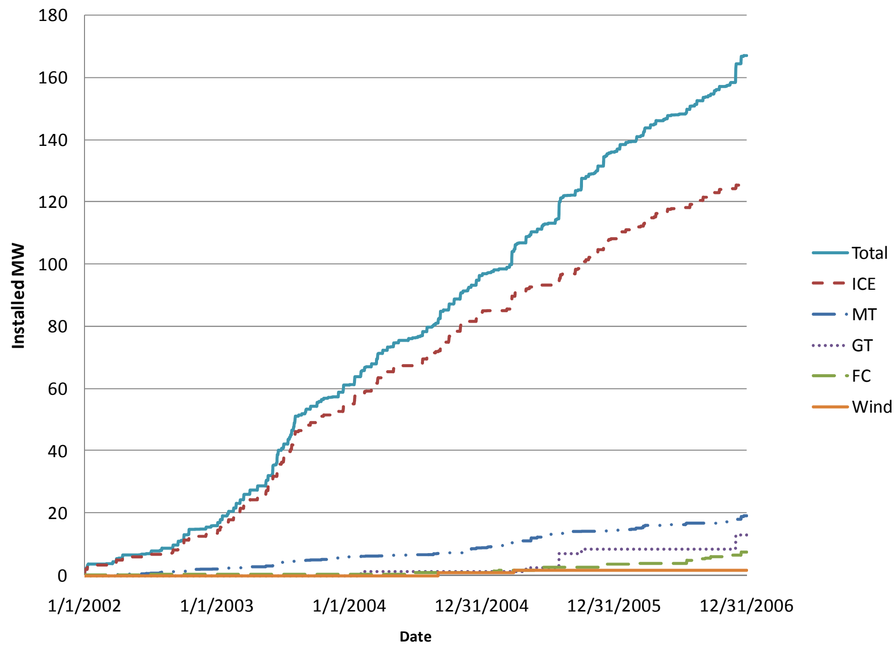

Table 3 below shows the total installed capacity and number for installations for the non-PV technologies.

Table 3. Summary Data for non-PV installations

Technology	Installed Capacity (MW)	n
ICE	127.8	204
MT	19.1	120
FC	7.5	13
GT	13.0	5
Wind	1.6	2
Total	169.0	344

Itron provided all the metering and installation data used to determine the performance of the SGIP installations. The data collected by Itron for each metered SGIP installation include:

- Electricity Data – kWh produced in 15 minute intervals
- Fuel Data — kBtu of NG consumed in 15 minute intervals (can either be non-renewable or renewable gas)
- Heat Data — Combine Heat and Power Energy in kBtu recovered by the system in 15 minute intervals

Of the 344 non-PV installations, only 57 percent were partially or fully metered. Table 4 shows the percent data coverage for electricity, fuel and heat data. Note that the "total" in Table 4 is not the sum of the previous elements in the table. Rather it refers to the percent of data relative to the total possible data points for all installations, including ENGO data, fuel data, and waste heat recovery data. It is an average of these three (3) data elements.

Table 4. Percentage of Data Coverage

Data Type	% Data Coverage
Electricity	53%
Fuel	32%
Heat	17%
Total data coverage	33%

The information in Table 4 indicates that a significant percentage of performance data needed to be estimated to determine the impact of each technology (including electricity production, fuel used and heat captured). Once the performance through 2006 is determined, then a typical performance year can be estimated to determine lifetime performance.

Estimating Electricity Performance

To interpolate missing and unmetered electricity data for the non-PV installations, TIAX calculated weighted average capacity factors for each hour between 2002 and 2006 from installations with metered data. This weighted average capacity factor is applied to the entire installed capacity to determine the estimated electricity production every hour for all installations. In this data set, null data (unmetered data) were not included, but zeros (metered data but the equipment is not operating) were included. These data are included for an accurate representation of real world situations where it is unreasonable to assume that all equipment will be operational at all times. Whether it is for periodic or major maintenance, electricity generation equipment is not operational at some point in time.

To determine the typical performance year for estimating electricity production from 2007 through 2035, TIAX averaged the weighted capacity factors from 2002 through 2006 for each representative hour. For example, the capacity factor at 9:00 AM on March 12 during typical performance year is the average of the weighted capacity factors at 9:00 AM on March 12 of years 2002, 2003, 2004, 2005 and 2006. This methodology for estimating a typical performance year was used for all technologies. For 2002-2035, the average monthly installed capacity was multiplied by the sum of the capacity factors for each hour during that month to determine the monthly MWh production.

Estimating Fuel Consumption

TIAX used both the electricity and fuel data to determine a fuel use factor. This factor is the average fuel required per unit of electricity (kWh) produced. Due to the variations in the technology, a separate fuel use factor was calculated for each technology.

TIAX identified dates and times when both an electricity and fuel data point for an installation were available. TIAX calculated the total kWh produced and kBtu consumed from these paired data points. The ratio of the total kBtu consumed to the total kWh produced is the fuel use factor for that technology. For each month, the MWh production is multiplied by the fuel use factor to determine the monthly fuel use. TIAX also considered the proportion of renewable versus non-renewable installations to determine the differential in natural gas use.

It is important to separate the renewable and non-renewable natural gas used when determining the environmental impacts because renewable natural gas will receive a credit in the greenhouse gas (GHG) emissions, as it is assumed that this fuel would have otherwise been flared to carbon dioxide (CO_2) without extracting the energy.

Estimating Heat Recovery Using Combined Heat and Power

Installations utilizing natural gas powered technologies can also install combined heat and power which utilizes the residual exhaust energy either as heat, which substitutes the use of the a boiler, or in an adsorption chiller for cooling, which substitutes the use of an electric chiller. Table 5 below shows the amount of the combined heat and power that has been installed for natural gas installations (excluding wind) through 2006 and indicates the percentage of installations using heating or cooling (Itron August 2007).

Table 5. Heating and Cooling Use of Recovered Heat

Heat End Use	Installed MW	% of Total
Heat Only	69.9	42.3%
H&C	35.5	21.5%
C Only	20.7	12.5%
TBD	23.2	14.0%
No CHP	16.1	9.8%

H&C (Heating and Cooling), C (Cooling), TBD (To be determined),CHP(Combined Heat and Power)

Since TIAX only received a sample of the SGIP data sheets that list installation equipment, TIAX could not determine which installation and technology had heat recovery for heating, cooling, both, or neither. Therefore, TIAX used the percentages in Table 5 to determine how much heat recovered is allocated to heating or cooling for each technology. For installations employing both heating and cooling, the percentage was split evenly and for the TBD, the percentage was split proportionally between heating only and cooling only. Therefore, of the natural gas technologies, an estimated 64 percent of the MWh utilize heating combined heat and power and 26 percent of the MWh utilize cooling combined heat and power.

TIAX employed the same process described previously to determine heat recovery factors. TIAX determined pairs of electricity production and heat recovered data points and calculated the total electricity produced and heat recovered from these pairs of points. The ratio of the total kBtu recovered to the total kWh produced is the heat recovery factor for the technology. For each month, the MWh production is multiplied by the heat recovery factor to determine the heat recovered.

Upon determining the heat recovered per month, the heating and cooling percentages are used to determine how much of this heat goes to cooling and heating. TIAX made the baseline assumption that in the absence of the generator or the combined heat and power application, that heat energy would be derived from a boiler utilizing natural gas and cooling energy could be derived from an electric chiller utilizing electricity. The natural gas savings and electricity savings via combined heat and power applications was determined as a differential using this baseline assumption. TIAX assumes all of the energy adsorbed for heating is utilized as heat while the energy adsorbed for cooling needs to have a chiller efficiency to convert warm exhaust energy to cool energy. The formulas below were employed to convert heat recovered to either kBtu natural gas savings from a boiler or kWh savings from an electric chiller.

Heat Recovery as Natural Gas Savings

$$\begin{bmatrix}\text{Boiler}\\ \text{Natural}\\ \text{Gas Savings}\end{bmatrix} kBtu * \left[\mathrm{Eff}_{\text{boiler}}\right]\frac{kBtu_{Heat}}{kBtu_{NG}} = \left[\text{CHP Heat Recovered}\right] kBtu$$

$$\begin{bmatrix}\text{Boiler}\\ \text{Natural}\\ \text{Gas Savings}\end{bmatrix} kBtu = \frac{\left[\text{CHP Heat Recovered}\right] kBtu}{\left[\mathrm{Eff}_{\text{boiler}}\right]\frac{kBtu_{Heat}}{kBtu_{NG}}}$$

$$\left[\mathrm{Eff}_{\text{boiler}}\right]\frac{kBtu_{Heat}}{kBtu_{NG}} = 0.85 \quad \text{Boiler Efficiency in converting natural gas energy to heat energy}$$

The 85 percent efficiency is based on energy star labels small gas boilers (GAMA March 31, 2008).

Heat Recovery at Chiller Electricity Saving

$$\begin{bmatrix}\text{Chiller}\\ \text{Electric}\\ \text{Savings}\end{bmatrix} kWh * \left[\mathrm{Eff}_{\text{Electric}}\right]\frac{ton \bullet hr_{cold}}{kWh} * \frac{12\ \text{kBtu}_{\text{cold}}}{1 ton \bullet hr} = \begin{bmatrix}\text{CHP Heat}\\ \text{Recovered}\end{bmatrix} kBtu_{hot} * \left[\mathrm{COP}_{\text{HRAC}}\right]\frac{kBtu_{cold}}{kBtu_{hot}}$$ from

$$\begin{bmatrix}\text{Chiller}\\ \text{Electric}\\ \text{Savings}\end{bmatrix} kWh = \frac{\begin{bmatrix}\text{CHP Heat}\\ \text{Recovered}\end{bmatrix} kBtu_{hot} * \left[\mathrm{COP}_{\text{HRAC}}\right]\frac{kBtu_{cold}}{kBtu_{hot}}}{\left[\mathrm{Eff}_{\text{Electric}}\right]\frac{ton \bullet hr_{cold}}{kWh} * \frac{12\ \text{kBtu}_{\text{cold}}}{1 ton \bullet hr}}$$

Note that both equations are taken from a previous Itron report (Itron September 14, 2005).

$$\left[\mathrm{COP_{HRAC}}\right]\frac{kBtu_{cold}}{kBtu_{hot}} = 0.6 \quad \text{Coefficient of Performance in heat recovery for an absorption chiller}$$

$$\left[\mathrm{Eff_{Electric}}\right]\frac{ton \bullet hr_{cold}}{kWh} = 0.6 \quad \text{Effeciency of an electric chiller converting electricity to cooling}$$

The 0.6 coefficient of performance is based on a report by Zaltash *et al*. for Oakridge National Laboratory (Zaltash 2005). The 60 percent electric chiller efficiency is based on the average for recommended full load optimized chillers by the Federal Energy Management Program.[8]

Environmental Impacts

Benefits as Damage Costs

TIAX determined the environmental impacts as reductions (or increases) in damages to environmental service flows attributable to the generation of electricity. Damages can be avoided by providing electricity via renewable and low(er)-emission technologies. The damages considered here include: direct damages to humans, indirect damages to humans through ecosystem degradation, and indirect damages to humans through non-living systems. The reader is referred to Section 7 of the U.S. Environmental Protection Agency's (EPA) Office of Air Quality and Planning & Standards Economic Analysis Resource Document for additional detail (EPA 1999).

Direct damages to humans include both health damages and aesthetic damages. Health damages result from human exposure to pollutants and include: increases in mortality and morbidity risk. Adverse health effects can be separated into acute effects (e.g., headaches) and chronic effects (e.g., asthma). Aesthetic damages result from the contamination of the physical environment and include increased problems of odor, noise, and poor visibility.

Indirect damages to humans through ecosystems include productivity damages, recreational damages, and intrinsic nonuse damages. Productivity damages result from pollution damages to physical environments that support commercial activity, such as farmlands, forests, and commercial fisheries. Recreation damages results from the reduced quality of resources such as oceans, lakes, and rivers. Intrinsic or non-use damages include losses in the value people associate with preserving, protecting, and improving the quality of ecological resources that is not motivated by their own use of those resources.

Indirect human damages through non-living systems include damages to materials and structures (e.g., buildings and equipment) that are caused by pollution and can reduce the productivity of these assets.

[8] http://www1.eere.energy.gov/femp/procurement/eep_wc_chillers.html

Damage Costs

Primary and Secondary Particulate Matter

Centralized power generation and some distributed generation technologies emit particulate matter (PM) directly and form additional (i.e., secondary) PM through chemical and physical processes in the atmosphere, most notably through the emission of nitrogen oxides (NO_x). Numerous studies have linked elevated PM levels with premature deaths, increased hospitalizations for respiratory and cardiovascular causes, asthma and other lower respiratory symptoms, acute bronchitis, work loss days, and minor restricted activity days. The California Air Resources Board (CARB) recently conducted a study to quantify the health impacts and economic valuation of air pollution from ports and goods movement in California (CARB March 21, 2006). To quantify the adverse health effects of PM and other pollutants, the CARB reviewed concentration-response functions, which examine relationships between adverse health outcomes and air pollution levels. In the study, the CARB examined statewide emissions from goods movement related activities at an air basin level. In the analysis here, TIAX considered the premature deaths from primary and secondary PM (1200 and 940, respectively), and calculated a damage cost in dollars per ton ($/ton) based on the value of avoiding a single premature death ($7.9 million), and the total emissions attributable to primary and secondary PM (42 tons per day (tpd) and 1079 tpd, respectively). This results in a damage cost of $640,000 per ton for primary PM and $19,000 per ton for NO_x as secondary PM.

It is important to note that these damage cost values are a function of exposure and population density. In the case of primary PM, this is particularly relevant as the population exposed to primary sources of PM in electric power generation, whether it is from centralized or distributed generation sites, is likely lower than the population exposed to primary sources of particulate matter emitted from goods movement activities. On the other hand, secondary particulate matter is formed over the course of hours (and days), so the population density is less important as dispersion throughout the air basin is unlikely to change exposure rates significantly. In the absence of a comparable study linking air pollution from power generation to adverse health impacts, TIAX recognizes that these estimates for the damage cost of both primary PM and secondary PM are likely high.

Volatile Organic Compounds and Nitrogen Oxides

TIAX used damage cost estimates for VOC and NO_x that are consistent with a previous report conducted by TIAX for the Energy Commission and the Air Resources Board on the Benefits of Reducing Petroleum Dependence (TIAX 2003). The damage costs from that study are used again in this study, updated to 2006 dollars. Furthermore, TIAX has added to the damage costs for VOC and NO_x based on the report issued by the CARB. In that report, the CARB determined the damage costs of ozone in the same fashion that damage costs for PM and NO_x as a precursor to secondary PM were determined. In the presence of sunlight, VOC and NO_x participate in a series of chemical reactions that lead to ozone formation. As precursors to ozone, the damage costs of ozone are attributed to each of these compounds (note: this is for NO_x in the gas phase). Because ozone formation is a non-linear function of VOC and NO_x concentrations, it is difficult to attribute a fixed damage cost to either pollutant. Because both compounds are present in some concentration to form ozone, a simplifying assumption is made and half of the damage costs of ozone are attributed to each compound.

Carbon Dioxide

The marginal damage cost of carbon dioxide (CO_2), or the social cost of carbon (SCC) is an essential determinant when shaping climate policy. Because of the potential environmental benefits of distributed generation, and the SGIP's focus on renewable generation, it is important to use a reliable SCC based on the most recent estimates found in the academic literature. The Inter-Governmental Panel on Climate Change (IPCC) estimates $43 per metric ton of carbon, which is equivalent to about $12 per metric ton of CO_2 (in 2006 dollars). The IPCC estimate is based on a 2005 study by Tol (Tol 2005), in which 28 published studies with 103 estimates of SCC. He concluded that when only peer-reviewed studies are considered that "climate change impacts may be very uncertain but it is unlikely that the marginal damage costs of carbon dioxide emissions exceed $50 per ton carbon." Tol has since updated his 2005 study with a meta-analysis of 211 estimates of the SCC (Tol 2007).

The IPCC Working Group II Fourth Assessment Report indicates that the SCC of carbon is increasing at an annual growth rate of 2.4 percent; however, Tol's meta-analysis (Tol 2007) finds no evidence to support this claim. In the most recent National Highway Traffic and Safety Administration (NHTSA) Draft Environmental Impact Statement (NHTSA June 2008) the agency opted to use the adder; however, in light of Tol's more recent findings, TIAX did not include an annual adder. Furthermore, Tol's updated analysis does not significantly change the "best estimates" of SCC, and therefore, TIAX used $12 per metric ton of CO_2 for the damage cost.

Emission Factors

In this analysis, TIAX used emission factors for distributed and centralized power generation for air quality pollutants – volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM2.5) — and greenhouse gases (GHGs) — carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), reported cumulatively as carbon dioxide equivalents (CO_2-eq). In the case of air quality pollutants, the emission factors are determined on a statewide basis because the damages resulting from criteria pollutants are skewed towards local effects. The damages resulting from criteria pollutants are a function of exposure (i.e., proximity to the source), population, population density, and dispersion modeling. Although power generation in California may result in air quality disbenefits outside of the state as a result of upstream processing, transportation, or distribution of energy sources, it would add considerable uncertainty to this analysis to quantify these emissions. In the case of GHGs, the emissions are accounted for on a lifecycle basis because climate change is a global phenomenon and the estimated damages resulting from climate change will occur irrespective of the source of emissions. In other words, carbon emitted in California contributes to climate change the same as carbon emitted anywhere else. It can be argued that the damages of climate change are not the same across states, nations, or continents; however, TIAX is unaware of any research that estimates the damage costs of GHGs on a uniquely local, regional, or national scale.

In a previous report for the Energy Commission (TIAX June 2007), TIAX quantified the emissions associated with electrical generation sources as part of an evaluation of the lifecycle (i.e., full fuel cycle) emissions of transportation fuels (note: electricity is considered an alternative transportation fuel). To determine the emissions associated with generation sources, TIAX compiled emission factors and efficiency factors for various combinations of equipment and fuels of interest. Furthermore, TIAX distinguished between in-state and total emissions. The in-state emission factors for air quality pollutants account for NO_x and PM offsets that are required for new facilities.

Marginal Power Generation

Marginal power generation is defined in this report as a natural gas fired combined cycle combustion turbine (NG CCCT), assuming that the next installed watt of power would come from a NG CCCT power plant. The marginal baseline is based on a series of assumptions, namely: the amount of nuclear powered, hydroelectric and coal powered electricity generation within and imported into California remains constant; California's aging fleet of steam generators will be repowered with NG CCCTs; future long-term contracts for imported power will have emissions consistent with NG CCCTs; and generation capacity will expand slightly ahead of demand in an orderly fashion (i.e., no supply disruptions from nuclear, hydroelectric, or coal resources). It is important to note that although self-generation installations often operate at peak demand, for instance solar PV systems, and may displace emissions from dirtier generation sources such as low efficiency 'peaker' plants, TIAX made a simplifying assumption and note that the reported environmental impact estimates would be higher if dirtier sources of power generation were included.[9]

Table 6 and Table 7 list the relevant emission factors for the DG technologies considered in this analysis, marginal power generation, and the corresponding damage costs for each pollutant considered.

Note that there is not a reliable estimate of the damage cost of CO. However, the emissions are quantified in this report because the EPA defines CO as a criteria pollutant. Furthermore, in the event that future research provides a reliable estimate for the damage cost of carbon monoxide, the emission (dis)benefits to the SGIP can be updated appropriately.

[9] Note that the lifecycle GHG emissions of the average mix of California power generation is only 5 percent higher than a NG CCCT power plant.

Table 6. Emission Factors for DG Technologies (all shown in lb/MWh)

	Pollutants	ICE [a]	MT [b]	GT [c]	FC	Boiler [d]
air quality	VOC	4.0×10^{-1}	5.0×10^{-2}	7.2×10^{-3}	0	2.0×10^{-2}
	NO_x	7.0×10^{-1}	1.7×10^{-1}	$.0 \times 10^{-1}$		1.2×10^{-1}
	CO	1.1	2.3×10^{-1}	7.0×10^{-2}		3.1×10^{-1}
	PM2.5	2.6×10^{-4}	2.3×10^{-2}	3.4×10^{-3}		2.8×10^{-2}
climate change	GHGs	63.25[e]				

[a] . For VOC, CO, and PM2.5, based on EPA AP-42; for NOx based on CA DG Regulations; EPA AP-42: http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf; CA DG Regulations: http://www.baaqmd.gov/pmt/handbook/rev02/PH_00_05_02_04_01.pdf

[b] For VOC, NOx, CO based on Capstone Technical Reference Document ; PM2.5 based on CA DG Regulations

[c] For VOC, CO, and PM2.5, based on EPA AP-42; for NOx based on CA DG Regulations; EPA AP-42: http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf

[d] For VOC, NOx, CO, and PM2.5, based on EPA AP-42; EPA AP-42: http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

[e] in units of g/MJ NG, Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007

Table 7. Emission Factors for Marginal Power Generation and Damage Costs for Environmental Pollutants

	Pollutant	Emission Factors, g/kWh		$/ton
		Lifecycle	California	
air quality	VOC	5.0×10^{-2}	1.0×10^{-3}	8.9×10^{3}
	NO_x	4.5×10^{-2}	4.5×10^{-3}	3.4×10^{3} (gas phase) 19.0×10^{3} (as PM)
	CO	1.3×10^{-1}	6.3×10^{-2}	--
	PM2.5	1.0×10^{-2}	6.2×10^{-3}	640×10^{3}
climate change	GHGs	505		12

Macroeconomic Impacts

There are multiple methods used to estimate economic impacts associated with specific programs. One way to develop estimates of some of the benefits of the SGIP is to investigate the economic impacts of the program's expenditures. One of the principle ways economic benefits are derived from program expenditures is through the use of Input-Output (I-O) models.

I-O Modeling: IMPLAN

Inter-industry economic I-O models use a matrix representation of a national or regional economy to predict the effect of changes in one industry's production to consumers, other industries, government, and foreign suppliers. This study utilizes the IMPLAN (IMpact Analysis for PLANning) I-O modeling system to develop estimates of economic impacts for activities associated with various SGIP projects. IMPLAN was originally developed by the U.S. Department of Agriculture's Forest Service for the purposes of land and resource management planning. In 1993, the Minnesota IMPLAN Group, Inc. (MIG) was formed to privatize the development of IMPLAN and to spread its use among non-Forest Service users.

A major benefit of using IMPLAN is that specific expenditures can be allocated to a wide range of economic industries, 509 in total, in order to develop detailed estimates of economic impact, job creation, and tax revenues. Another important attribute of IMPLAN is its ability to develop models and results at the national, state, and county levels. These geographic units can be combined to construct any regional grouping the user desires. The ease with which alternative regional aggregations can be constructed, while preserving critical intra- and inter-regional trade flow information, is a principal advantage of IMPLAN.

Using classic I-O analysis in combination with regional specific Social Accounting Matrices and Multiplier Models, IMPLAN provides a highly accurate and adaptable model for its users. IMPLAN's Social Accounting System describes transactions that occur between producers, and intermediate and final consumers using a Social Accounting Matrix. One of the important aspects of Social Accounts is that they also examine non-market transactions, such as transfer payments between institutions. Other examples of these types of transactions would include: government to household transfers as unemployment benefits, or household to government transfers in the form of taxes. Because Social Accounting Systems examine all the aspects of a local economy, they provide a more complete and accurate "snapshot" of the economy and its spending patterns.

Multipliers are a numeric way of describing the impact of a change. An employment multiplier of 1.8 would suggest that for every 10 employees hired in a given industry, 18 total jobs (in all sectors) would be added to that region. The Multiplier Model is derived mathematically using the I-O model and Social Accounting formats. The Social Accounting System provides the framework for the predictive Multiplier Model used in economic impact studies. Purchases for final use drive the model. Industries that produce goods and services for consumer consumption must purchase products, raw materials, and services from other companies to create their product. These vendors must also procure goods and services. There are three types of effects measured with a multiplier: the direct, the indirect, and the induced effects. The direct effect is the known or predicted change in the local economy that is to be studied. The indirect effect is the business to business transactions required to satisfy the direct effect. Finally, the induced effect is derived from local spending on goods and services by people working to satisfy the direct and indirect effects.

Model Output

As mentioned earlier, to compare these costs and benefits of a program over time, the expected expenditures associated with the project alternatives can be run through the

IMPLAN model to develop estimates of their expected economic impacts. Specific economic impacts captured by the IMPLAN model include:

- Value added
- Jobs created (full time equivalents)
- Payroll compensation

It should be noted that the 'value added' to an economy because of a project, which is a results category provided by the IMPLAN model, is a better measure of economic benefits of a project than total expenditure because value added estimates more accurately represent the economic gains from economic activity that occur because of the existence of the project. In essence, value added is a better measure of economic impact than expenditure because the same level of expenditure spent in different settings and for different goods and services can have very different levels of secondary economic impacts on output, job creation, and tax revenues.

The value added impacts estimated by IMPLAN represent the benefit of project construction, operation, and maintenance costs. Other project benefits may be added to the IMPLAN outputs to estimate the total benefits. This is useful because once the total benefits of a project have been determined they can be compared to the costs of the project by performing a cost-benefit analysis.

Expenditure Data for the SGIP

Capital expenditure data by year and technology for PG&E, SCE, SCG, and SDGE were used to develop program level estimates of the benefits from SGIP expenditures. The eligible cost data were reported by year in nominal dollars. To use the reported data, the nominal yearly data were converted to real common year dollars. In order to select an appropriate inflation index, a number of annual inflation rate estimates were compared. The inflation rates that were compared include: the producer price index (PPI) for turbine and power transmission equipment manufacturing, PPI for finished goods, gross domestic product, and consumer price index. A summary of these inflation rate estimates is provided in Table 8.

All of the inflation rate estimates are fairly consistent in terms of 2001 to 2006 average yearly rates, except for the PPI for turbines and power transmission equipment, which is on average noticeably lower than the other rates. The lower inflation rate for turbines and transmission equipment is probably reflective of the lower demand for that equipment relative to other goods in the economy. This lower rate was not considered for overall inflation adjustment because those turbines and generators are only used in MT, GT, and WD projects, which account for less than 8 percent of all SGIP expenditures. Since the PPI for finished goods was between the average of the GDP and CPI inflation rates, the PPI measure was selected to convert all the reported nominal SGIP expenditures into real 2006 dollars. The results of applying the PPI for finished goods to the nominal capital expenditures reported for the SGIP are provided in Table 9. In total, $1.28 billion in capital expenditure occurred in the period from 2001 to 2006 with the largest expenditures on PV and ICE-NR.

Table 8. Relevant Inflation Indexes

Year	Producer Price Index: Turbine & Power Transmission Equip Mfg[a]	Producer Price Index: Finished Goods[a]	GDP[b]	CPI[a]	Average
2000	0.72	4.37		3.94	3.01
2001	0.87	2.23	0.91	3.24	1.81
2002	0.93	-1.48	1.80	1.77	0.76
2003	0.15	3.55	2.74	2.50	2.23
2004	1.28	3.92	3.81	2.84	2.96
2005	1.76	4.99	2.98	3.50	3.31
2006	3.35	3.02	2.80	3.23	3.10
2007	3.01	3.72	1.96	2.77	2.87
2008	3.13	5.96		3.56	4.22
01-'06 Avg	1.39	2.71	2.51	2.85	2.36

[a] Bureau of Labor Statistics (BLS), http://www.bls.gov/bls/inflation.htm
[b] Bureau of Economic Analysis (BEA), http://www.bea.gov/national/index.htm

The nominal incentive payments were also converted to 2006 dollar equivalents using the PPI for finished goods. A table summarizing the incentive payments in real 2006 dollars is provided in Table 10.

In addition to capital costs, the SGIP includes operation and maintenance costs, which are paid for by the operators of the individual projects. Operation and maintenance costs are further addressed later in Chapter 2 and again in Chapter 3 of this report.

Categorizing Program Expenditures by Economic Sectors

To develop economic impact estimates from the expenditures listed previously it is necessary to classify them by the economic sectors utilized by the I-O model. Preparing the data for IMPLAN analysis involves: identifying program expenditure categories, assigning SGIP expenditure categories to IMPLAN sectors, aggregating expenditure categories assigned to the same sectors, and developing the expenditure levels to assign to each relevant sector in the model.

A complete breakdown of SGIP expenditures by item for each individual installation was not available at the time this analysis was performed. Nevertheless, sample data from 283 installations were available. The samples included include examples of all the technologies except wind turbines. Among the 283 installations, 90 different costs categories were identified. For example, the sample data provided installed cost breakdowns for 38 microturbine installations utilizing non-renewable energy. A partial list of cost categories and associated expenditures for a sample microturbine installation is provided in Figure 2.

Table 9. SGIP Expenditure Estimates (in millions $2006)

	PG&E						**SCE**						**SCG**						**SDGE**						
	01	02	03	04	05	06	01	02	03	04	05	06	01	02	03	04	05	06	01	02	03	04	05	06	**sub-total**
PV	--	20.5	45.7	98.9	104.6	158.6	--	2.3	21.6	31.0	54.1	74.1	--	3.4	46.8	16.2	11.8	23.0	--	10.8	11.6	14.4	34.7	39.8	**823.9**
ICE-NR	0.6	4.7	44.2	19.8	38.3	12.2	1.2	5.0	12.7	8.3	10.6	11.0	--	7.4	42.2	30.4	3.1	8.5	0.2	6.6	4.3	9.0	8.2	--	**288.6**
ICE-R	--	--	--	1.1	--	10.8	--	--	--	--	1.4	2.9	--	--	--	--	--	3.0	--	--	--	--	--	--	**19.2**
MT-NR	--	--	4.0	7.0	5.7	6.9	--	0.4	0.8	3.6	5.5	1.3	--	1.0	4.9	0.3	4.4	0.6	2.0	2.3	0.5	0.6	0.2	--	**51.9**
MT-R	--	--	2.0	1.6	2.3	1.9	--	1.8	--	1.3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**10.9**
FC-NR	--	4.2	--	4.6	7.4	12.2	--	--	--	--	--	1.7	--	--	--	--	--	8.6	--	--	--	--	7.2	3.0	**48.8**
FC-R	--	--	--	--	--	--	--	--	--	--	7.5	--	--	--	--	--	--	--	--	--	--	--	--	--	**7.5**
GT-NR	--	--	4.2	--	12.2	--	--	--	--	--	--	--	--	--	--	--	8.6	--	--	--	--	--	6.5	--	**31.6**
WD	--	--	--	--	--	--	--	--	--	2.3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**2.3**
																								total	**1284.7**

Table 10. SGIP Incentive Payments (in millions $2006)

	PG&E							SCE						SCG							SDGE						
	02	03	04	05	06	07	08	02	03	04	05	06	07	02	03	04	05	06	07	08	02	03	04	05	06	07	**sub-total**
PV	8.1	16.2	44.3	50.9	52.0	22.7	0.2	0.6	8.9	14.6	25.9	26.3	9.6	0.4	9.6	2.8	5.7	5.9	4.4	--	0.4	7.4	4.2	17.1	9.9	7.8	356.1
ICE-NR	--	5.7	8.8	5.9	8.1	1.5	--	0.9	3.1	3.1	1.1	5.3	0.8	1.2	4.3	8.1	3.2	3.9	1.7	--	0.3	1.1	1.9	1.4	1.9	--	73.2
ICE-R	--	--	--	--	3.6	0.2	--	--	--	--	0.6	--	1.0	--	--	--	--	--	--	0.9	--	--	--	--	--	--	6.2
MT-NR	--	0.1	0.9	1.9	1.5	0.5	0.8	0.1	23.7	0.7	1.7	0.7	--	0.1	0.8	0.9	0.4	1.4	0.1	--	0.1	0.4	0.7	0.2	0.0	--	37.7
MT-R	--	--	0.1	0.6	1.1	0.4	--	--	0.5	0.2	0.4	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	3.4
FC-NR	0.6	--	1.6	2.5	3.3	--	--	--	--	--	--	0.5	--	--	--	--	--	1.3	2.2	--	--	--	--	--	3.7	--	15.7
FC-R	--	--	--	--	--	--	--	--	--	--	3.5	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	3.5
GT-NR	--	--	0.9	1.0	--	1.0	--	--	--	--	--	--	--	--	--	--	--	0.6	--	--	--	--	--	--	0.5	--	3.9
WD	--	--	--	--	--	--	--	--	--	--	1.0	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	1.0
																										total	**500.7**

Figure 2. Example of Expenditures for a Sample Installation

Item No.	Cost Category	Sub-category	Cost of Items
1	Planning & Feasibility Study Costs		$24,739.00
2	Engineering & Design Costs		$107,706.00
3	Permitting Costs (air quality, building permits, etc.)		$0.00
4	Self-Generation Equipment Costs (generator, ancillary equipment) - fill out		
		Capital equip	$755,988.00
		Site monitoring - data acquisition	$93,539.00
		Air Emission Control equip	$0.00
		Foundations-mounting hardware	$30,167.00
5	Waste Heat Recovery Costs (not including thermal application eqp.)		
		Heat exchanger	$16,166.00
		Piping to heat applications	$86,500.00
6	Construction & Installation Costs (labor & materials)		
		Electrical	$253,103.00
		Mechanical	$317,817.00
		Civil	$27,250.00
		Thermal	$16,250.00
7	Interconnection Costs - Electric (customer side of meter only)		$22,265.00
		Elec grid application fees	$0.00
		Metering	$0.00
		Switch and switchgear	$0.00
		Other interconnect costs	$0.00
8	Interconnection Costs - Gas (customer side of meter only)		
		Enhancement of existing service	$144,173.00
		Gas line	$0.00
9	Warranty Cost (if not already included in Item 4)		$0.00
10	Maintenance Contract Cost (only if arranty is insufficient)		$0.00
11	Sales Tax		$0.00
12	Other Eligible Costs (Itemize Below)		
	12a	Project mgmt	$88,808.00
	12b	Contingency	$75,591.00
	12c	Commissioning	$18,898.00
	12d	Training	$18,898.00
	12e	General conditions	$18,898.00
	12f	Bonds	$14,640.00

The expenditure categories for various installations were provided by the program participants. The expenditure categories are useful because they can be used to develop economic benefit estimates using the IMPLAN model. However, in order to run the collected data for the various expenditure categories through the I-O model, the expenditure categories have to be assigned to economic sector categories recognized by the IMPLAN model.

Assigning expenditure categories to appropriate sectors in the IMPLAN model is a two-step process. The first step is to assign the expenditure categories to North American Industry Classification System (NAICS) codes, which are developed by the U.S. Census Bureau. The second step is to convert the NAICS codes into IMPLAN sector codes. For example, the eligible program costs for “Engineering and Design Costs” are classified as “Engineering Services”, NAICS code 541330, and converted to “Architectural and Engineering Services”, IMPLAN sector code 439. Assigning cost categories to NAICS codes before assigning them to IMPLAN sector codes is helpful because the NAICS codes provide more description of the code categories than the IMPLAN sectors. Once the cost categories have been assigned to NAICS codes they can be easily converted to IMPLAN sector codes using a conversion guide developed by IMPLAN. A list of the NAICS and IMPLAN codes assigned to eligible and ineligible SGIP costs such as Self-Generation Equipment Costs, Waste Heat Recovery Costs, and Maintenance Contract Costs for microturbines are provided in Figures 3 and 4, respectively. Eligible and ineligible program costs are explained later in this section.

The sector assignments for equipment categories in Figures 3 and 4 represent the delivered cost of the equipment to the final user. Prior to running the IMPLAN model, the portion of those costs attributable to wholesale and transportation, referred to as margins by economists, can be subtracted and assigned to the appropriate wholesale and transportation sectors to account properly for those economic sectors. However, due to insufficient information about the wholesale and transportation of SGIP related manufactured goods, a margin analysis was not performed. It is estimated that factoring in margins to the economic impacts analysis might increase the value added results discussed in Chapter 3, Macroeconomic Impacts by 1-2 percent.

Regional Purchase Coefficients

Expenditure on goods and services for SGIP related construction, operation, and maintenance generates economic impacts for businesses and workers inside and outside California. This report is concerned with economic impacts that occur and remain within California. To estimate the economic impacts these regional impacts, a regional purchase coefficient (RPC) is used. RPCs represent the proportion of goods and services that will be purchased regionally under normal circumstances, based on the area's economic characteristics described in terms of actual trade flows within the area. RPCs are usually expressed as a percentage of total impacts, both local and nonlocal.

IMPLAN assigns default RPCs to each of its 509 sectors based on the region selected for analysis. The RPC values used in this analysis are the default California values. Table 11 lists the relevant IMPLAN sectors and the default California specific RPCs assigned to those sectors.

Figure 3. Assignment of Eligible Project Costs to NAICS Codes and IMPLAN Sector Codes for Microturbines

Item No.		Eligible Cost Elements	NAICS CODE 2007	NAICS CODE DESCRIPTION	IMPLAN SECTOR	IMPLAN SECTOR DESCRIPTION
1	Planning & Feasibility Study Costs		541330	Engineering Services	439	Architectural and engineering services
2	Engineering & Design Costs		541330	Engineering Services	439	Architectural and engineering services
3	Permitting Costs (air quality, building permits, etc.)					
		Air Pollution	92411	Administration of Air and Water Resource and Solid Waste Management Programs	504	State & Local Non-Education
		Building	926130	Regulation and Administration of Communications, Electric, Gas, and Other Utilities	504	State & Local Non-Education
		Other	926130	Regulation and Administration of Communications, Electric, Gas, and Other Utilities	504	State & Local Non-Education
4	Self-Generation Equipment Costs (generator, ancillary equipment)					
		Capital equip	333611	Turbine and Turbine Generator Set Units Manufacturing	285	Turbine and turbine generator set units manufacturing
		Site monitoring - data acquisition	518	Data Processing, Hosting, and Related Services	424	Data processing computer services
		Air Emission Control equip	333411	Air Purification Equipment Manufacturing	275	Air purification equipment manufacturing
		Foundations-mounting hardware	332510	Hardware Manufacturing	241	Hardware Manufacturing
5	Waste Heat Recovery Costs (not including thermal application eqp.)					
		Heat exchanger	332410	Power Boiler and Heat Exchanger Manufacturing	238	Power boiler and heat exchanger manufacturing
		Piping to heat applications	332996	Fabricated Pipe and Pipe Fitting Manufacturing	252	Fabricated pipe and pipe fitting manufacturing
6	Construction & Installation Costs (labor & materials)					
		Electrical	237990	Other Heavy and Civil Engineering Construction	41	Other new construction
		Mechanical	237990	Other Heavy and Civil Engineering Construction	41	Other new construction
		Civil	237990	Other Heavy and Civil Engineering Construction	41	Other new construction
		Thermal	237990	Other Heavy and Civil Engineering Construction	41	Other new construction
7	Interconnection Costs - Electric (customer side of meter only)					
		Elec grid application fees	926130	Regulation and Administration of Communications, Electric, Gas, and Other Utilities	504	State & Local Non-Education
		Metering	334515	Instrument Manufacturing for Measuring and Testing Electricity and Electrical Signals	318	Electricity and signal testing instruments
		Switch and switchgear	335313	Switchgear and Switchboard Apparatus Manufacturing	335	Switchgear and switchboard apparatus manufacturing
		Other interconnect costs	335314	Switchgear and Switchboard Apparatus Manufacturing	336	Switchgear and switchboard apparatus manufacturing
8	Interconnection Costs - Gas (customer side of meter only)					
		Enhancement of existing service	238220	Gas line installation, individual hookup, contractors	41	Other new construction
		Gas line	238220	Gas line installation, individual hookup, contractors	41	Other new construction
9	Warranty Cost (if not already included in Item 4)		524128	Warranty insurance carriers (e.g., appliance, automobile, homeowners, product)	427	Insurance carriers
10	Maintenance Contract Cost (only if arranty is insufficient)		237990	Other Heavy and Civil Engineering Construction	45	Other maintenance and repair construction
11	Sales Tax		92613	Regulation and Administration of Communications, Electric, Gas, and Other Utilities	504	State & Local Non-Education
12	Other Eligible Costs (Itemize Below)					
	12a	Construction mgmt	237990	Other Heavy and Civil Engineering Construction	41	Other new construction
	12b	Inspection & testing	541380	Testing Laboratories	439	Architectural and engineering services
	12c	CM fee	237990	Other Heavy and Civil Engineering Construction	41	Other new construction

Figure 4. Assignment of Ineligible Project Costs to NAICS Codes and IMPLAN Sector Codes for Microturbines

Item No.		Ineligible Cost Elements	NAICS CODE 2007	NAICS CODE DESCRIPTION	IMPLAN SECTOR	IMPLAN SECTOR DESCRIPTION
1	Fuel Supply Costs (digesters, gas gathering, etc.)		332420	Metal Tank (Heavy Gauge) Manufacturing	239	Metal tank, heavy gauge, manufacturing
2	Ineligible Self-Generation Equipment Cost		333611	Turbine and Turbine Generator Set Units Manufacturing	285	Turbine and turbine generator set units manufacturing
3	Electricity Storage Devices		335911	Storage Battery Manufacturing	337	Storage battery manufacturing
4	Thermal Load Costs (new absorption chillers, boilers, etc.)		332410	Power Boiler and Heat Exchanger Manufacturing	238	Power boiler and heat exchanger manufacturing
5	Interconnection Costs - Electric (work on utility side of meter)		335313	Switchgear and Switchboard Apparatus Manufacturing	335	Switchgear and switchboard apparatus manufacturing
6	Interconnection Costs - Gas (work on utility side of meter)		238220	Gas line installation, individual hookup, contractors	41	Other new construction
7	Warranty Costs (beyond SGIP requirement)		524128	Warranty insurance carriers (e.g., appliance, automobile, homeowners, product)	427	Product warranty insurance carriers, direct
8	Maintenance Contract Costs (beyond SGIP requirement)		237990	Other Heavy and Civil Engineering Construction	45	Other maintenance and repair construction
9	Other Ineligible Costs (Itemize Below)					
	9a	Buildings to house and/or support generation equipment	236210	Industrial Building Construction	37	Manufacturing and Industrial Buildings

Table 11. Regional Purchase Coefficients (RPCs) in IMPLAN

IMPLAN Sector	IMPLAN SECTOR DESCRIPTION	RPC (%)
31	Natural gas distribution	95
37	Manufacturing and Industrial Buildings	100
41	Other new construction	100
45	Other maintenance and repair construction	86
205	Iron and Steel Pipe and Tube Manufacturing from purchased steel	0
238	Power boiler and heat exchanger manufacturing	1
239	Metal tank; heavy gauge; manufacturing	3
241	Hardware Manufacturing	2
252	Fabricated pipe and pipe fitting manufacturing	16
275	Air purification equipment manufacturing	0
277	Heating equipment; except warm air furnaces	0
285	Turbine and turbine generator set units manufacturing	50
311	Semiconductor and Related Device Manufacturing	84
312	All other electronic component manufacturing	51
318	Electricity and signal testing instruments	19
334	Motor and generator manufacturing	5
335	Switchgear and switchboard apparatus manufacturing	30
337	Storage battery manufacturing	16
343	Miscellaneous electrical equipment manufacturing	8
394	Truck transportation	78
424	Data processing computer services	29
427	Insurance carriers	65
437	Legal Services	90
439	Architectural and engineering services	90
458	Services to buildings and dwellings	80
484	Electronic equipment repair and maintenance	87
485	Commercial machinery repair and maintenance	80
504	State & Local Non-Education	100

TIAX and JFA reviewed the default California specific RPCs in the IMPLAN model and identified the RPC for the Semiconductor and Related Device Manufacturing, (IMPLAN sector 311) as the most sensitive relative to other manufacturing related RPCs and the large amount of expenditure in the category. Accordingly, a sensitivity analysis was performed using the original IMPLAN default value of 84 percent and a value of 50 percent. The results of the sensitivity analysis are presented alongside the results of the RPC default values in Chapter 3, Macroeconomic Impacts.

The proxy installed cost ratios developed from the study sample were applied to total installed cost estimates for the entire SGIP between 2001 and 2006 to develop program expenditure estimates for each installed cost category. The installed cost categories were matched and assigned to IMPLAN sectors. Installed cost categories that were assigned to the same IMPLAN sector were aggregated by IMPLAN sector. The dollar estimates for these aggregated IMPLAN sectors were then run through the I-O model to develop estimates of the economic impacts of the SGIP. For example, construction and installation costs, maintenance contract costs, and other eligible costs, all of which were classified to the "other new construction" IMPLAN sector code, were summed prior to being processed through the model.

Once the cost categories assigned to the same IMPLAN sectors have been aggregated, the percentage of total expenditures accounted for by each cost category is calculated. For example, for the microturbine installations in the study sample, the program participants indicate that "Engineering and Design Costs" comprise about 5.8 percent of installed expenditure. In the absence of cost breakdowns for all installations in the SGIP the expenditure percentages for the study sample are the best available proxy.

A breakdown of the expenditures in the study sample was used to develop percentages for each expenditure category by technology. Expenditure categories that were provided in the study sample include: feasibility and design study costs, engineering and design costs, and capital equipment cost, among other categories. This breakdown is useful because the economic impacts of program expenditures are calculated in the IMPLAN model by assigning the expenditures to specific economic sectors indentified by the model. The percentage of capital expenditures assigned to each IMPLAN sector for each technology is provided in Table 12. For example, depending on the technology, 2.4 to 12.4 percent of expenditures were attributed to the architectural and engineering services sector.

Ineligible Cost Escalation Factors

Installed costs are classified as either eligible or ineligible under the SGIP. Eligible costs are eligible for incentive payment reimbursements, whereas ineligible costs are not. The economic impacts of total eligible and ineligible costs are included in the economic impact analysis because the economic activity generated by the installed costs is not affected by whether the program participants are reimbursed or not for their installed cost expenditure. Since the total SGIP costs in Table 9 were only provided for eligible costs, the ratio of eligible costs to ineligible costs by technology in the SCE sample were used to scale up the SGIP installed cost estimates. Ineligible costs, as a percentage of totals costs (by technology) are provided in Table 13.

Accordingly the inflation adjusted capital expenditure estimates in Table 9 were escalated by the ineligible costs percentages of total costs for the study sample. The results of this escalation are provided in Table 14. The "with provided ineligible cost" column represents the escalation of the inflation adjusted SGIP capital expenditure estimates by the ineligible cost percentages in Table 13.

Table 12. Percentage of Capital Expenditures Assigned to IMPLAN Sectors

IMPLAN Sector	IMPLAN Sector Description	PV	ICE-NR	ICE-R	MT-NR	MT-R	FC-NR	FC-R	GT
439	Architectural and engineering services	2.4	8.7	8.8	6.0	12.4	6.5	6.5	8.2
504	State & Local Non-Education	3.3	5.2	4.1	2.3	3.4	5.2	5.2	2.4
311	Semiconductor and Related Device Manufacturing	55.0	0.0	0.0	0.0	0.0	43.4	43.4	0.0
334	Motor and generator manufacturing	0.0	17.2	13.0	0.0	0.0	0.0	0.0	0.0
277	Heating equipment, except warm air furnaces	0.0	2.6	2.0	0.0	0.0	4.8	4.8	0.0
424	Data processing computer services	0.0	1.4	1.0	3.2	4.1	2.2	2.2	2.1
275	Air purification equipment manufacturing	0.0	2.5	1.9	0.0	0.0	0.0	0.0	0.0
343	Miscellaneous electrical equipment manufacturing	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
205	Iron and Steel Pipe and Tube Manufacturing from purchased steel	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
241	Hardware Manufacturing	1.1	1.5	1.1	1.2	1.5	2.4	2.4	0.8
252	Fabricated pipe and pipe fitting manufacturing	0.0	2.6	2.9	2.9	3.0	1.9	1.9	13.7
41	Other new construction	19.9	28.7	17.4	31.8	26.0	19.7	19.7	26.0
318	Electricity and signal testing instruments	0.2	0.8	0.6	0.2	0.1	0.4	0.4	0.2
335	Switchgear and switchboard apparatus manufacturing	0.6	3.3	2.4	2.5	1.3	1.5	1.5	2.0
427	Insurance carriers	0.6	1.8	1.3	6.6	0.3	6.8	6.8	3.8
485	Commercial machinery repair and maintenance	0.2	4.6	4.6	1.2	5.3	4.3	4.3	2.3
394	Truck transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
285	Turbine and turbine generator set units manufacturing	0.3	0.5	0.0	32.3	40.9	0.0	0.0	24.9
458	Services to buildings and dwellings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
239	Metal tank, heavy gauge, manufacturing	0.0	0.6	29.2	0.1	0.3	0.0	0.0	0.0
337	Storage battery manufacturing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
238	Power boiler and heat exchanger manufacturing	0.1	7.3	2.9	9.3	1.5	1.0	1.0	8.0
37	Manufacturing and Industrial Buildings	0.1	9.1	6.8	0.0	0.0	0.0	0.0	0.0
437	Legal Services	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
312	All other electronic component manufacturing	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
45	Other maintenance and repair construction	0.3	1.7	0.0	0.5	0.0	0.0	0.0	5.4
	Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**

Note: In the event that a column does not sum to 100 percent, it is a function of rounding and not a calculation error.

Table 13. Ineligible Costs for SGIP installations (in millions $2006)

PV	ICE-NR	ICE-R	MT-NR	MT-R	FC-NR	FC-R	GT-NR
1.13	9.95	29.25	13.24	1.14	0.45	0.45	11.72

Table 14. Escalating Capital Costs to Include Ineligible Costs (millions of $2006)

	w/o ineligible costs	w/ ineligible costs
PV	823.9	833.2
ICE-NR	288.6	317.3
ICE-R	19.2	24.9
MT-NR	51.9	58.8
MT-R	10.9	11.0
FC-NR	48.8	49.0
FC-R	7.5	7.5
GT-NR	31.6	35.3
WD	2.3	2.3
Total	**1,284.7**	**1,339.3**

Operations and Maintenance Costs

Operation and maintenance (O&M) costs were added to the capital expenditure costs. The four types of O&M costs were assigned to the IMPLAN sectors 31, 343, 484, and 485. A summary of the operation and maintenance costs is provided in Table 15. The natural gas distribution costs apply exclusively to technologies that use nonrenewable fuels. Accordingly, PV technologies do not incur this O&M expense. All the O&M expenditures occur annually except for inverters for the PV systems, which have to be replaced after 15 years. It should be noted that all installations, regardless of technology, are assumed to have a project life of 30 years. So the PV systems will only have one inverter replacement during their expected service life.

Table 15. Operation and Maintenance Costs (in millions $2006)

O&M Category	Frequency	IMPLAN Sector	PV	ICE	MT	FC	GT
Natural Gas Distribution	Annual	31	—	38.1	7.3	2.5	8.7
Electronic equipment repair and maintenance	Annual	484	0.4	—	—	—	—
Commercial machinery repair and maintenance	Annual	485		4.0	1.3	0.9	0.6
Miscellaneous electrical equipment manufacturing	Once	343	1.3	—	—	—	—

Note: O&M costs apply to both nonrenewable and renewable systems

The results of summing the O&M costs with the capital costs after they have been aggregated by IMPLAN sectors are provided in Table 16. Note that O&M costs total about $1.3 billion across all the technologies over the 30 year period and increase the

SGIP costs from $1.3 billion to $2.6 billion. These estimates are developed using real 2006 dollars and discounted at a rate of 2.8 percent per year over 30 years.

Table 16. Capital and O&M Costs for the SGIP

IMPLAN sector	description	Costs		
		Capital	O&M	Sum
31	Natural gas distribution	0.0	1142.1	1142.1
37	Manufacturing and Industrial Buildings	31.3	0.0	31.3
41	Other new construction	302.9	0.0	302.9
45	Other maintenance and repair construction	10.3	0.0	10.3
205	Iron and Steel Pipe and Tube Manufacturing from purchased steel	5.0	0.0	5.0
238	Power boiler and heat exchanger manufacturing	33.7	0.0	33.7
239	Metal tank; heavy gauge; manufacturing	9.2	0.0	9.2
241	Hardware Manufacturing	16.9	0.0	16.9
252	Fabricated pipe and pipe fitting manufacturing	16.8	0.0	16.8
275	Air purification equipment manufacturing	8.5	0.0	8.5
277	Heating equipment; except warm air furnaces	11.5	0.0	11.5
285	Turbine and turbine generator set units manufacturing	36.0	0.0	36.0
311	Semiconductor and Related Device Manufacturing	482.7	0.0	482.7
312	All other electronic component manufacturing	0.3	0.0	0.3
318	Electricity and signal testing instruments	4.3	0.0	4.3
334	Motor and generator manufacturing	57.9	0.0	57.9
335	Switchgear and switchboard apparatus manufacturing	19.5	0.0	19.5
337	Storage battery manufacturing	0.0	0.0	0.0
343	Miscellaneous electrical equipment manufacturing	125.0	0.9	125.8
394	Truck transportation	0.0	0.0	0.0
424	Data processing computer services	8.9	0.0	8.9
427	Insurance carriers	20.2	0.0	20.2
437	Legal Services	2.9	0.0	2.9
439	Architectural and engineering services	61.1	0.0	61.1
458	Services to buildings and dwellings	0.0	0.0	0.0
484	Electronic equipment repair and maintenance	0.0	8.7	8.7
485	Commercial machinery repair and maintenance	21.6	138.3	159.9
504	State & Local Non-Education	50.6	0.0	50.6
	Total	**1,337.0**	**1,289.9**	**2,626.9**

Grid Impacts

Table 17 shows a breakdown of a year’s worth of monthly electric service bills for a residential IOU customer for July 2007 through June 2008. In addition to environmental and socioeconomic issues, the table indicates that a comprehensive evaluation of the impacts of the SGIP participants and non-participants will involve nine (9) categories of service cost components. An assessment with this level of detail is very difficult to carry out, requires too much time, and is beyond the scope of this study; however, as discussed further here, it is not necessary to go into such excruciating detail.

Table 18 provides estimates of the SGIP incentive payment per-kWh of self-generated electricity. Using the 2005 SGIP incentive payment schedule, representative values of expected self-generating capacity factors and a fixed annual (capital recovery) charge rate of 15 percent, the costs of SGIP support translates into 1.3 to 13 cents per kWh (for non-renewable GTs to WD).[10] Returning to Table 17, generation as well as transmission and distribution (T&D) command 88 percent of the electric bill (17.4 cents/kWh). The remaining six cost components account only for 2.32 cents/kWh (12 percent). Self generation cannot reduce these six charges for non-participants. Thus any offsetting of the costs of the SGIP incentive payments would have to come from savings associated with the generation and T&D components.

The transmission charge accounts for only 4 percent (0.87 cents/kWh) of the total residential bill. Even if a participant's self-generation investment were to result in transmission savings for the system that could offset the entire 0.87 cents/kWh component, it would not be enough to make up for the lowest level of the 2005 SGIP support payment (1.3 cents per kWh, see Table 18). Transmission investments are designed to serve loads many orders of magnitudes greater than a local application of self generation. It is therefore difficult to conceive SGIP transmission cost reduction impacts exceeding even 10 percent of the total charge (or 0.087 cents/kWh in terms of the example residential electric bill). A sound approach to assessing the grid impacts of the SGIP should then focus on the generation and distribution components of the costs of electric power service.

Table 17. Residential Electric Bill Components [a]

	cents/kWh	percent
Generation	12.73	65%
Transmission	0.87	4%
Distribution	3.80	19%
Public Purpose Programs	0.94	5%
Nuclear Decommissioning	0.03	0.2%
Trust Transfer	0.35	2%
DWR Costs	0.47	2%
Competition Transition Charge	0.18	1%
Energy Cost Recovery	0.33	2%
Total Bill	19.70	100%

[a] For an IOU customer over a 12-month period, 7/2007 to 06/2008

[10] As shown in Table 18, PV investments which are no longer part of the SGIP could command as much as 30 cents/kWh.

Table 18. Incentive Payment Estimates (per unit of energy production)

technology	2005 incentives ($/Kw)	incentives ($/kW-yr) [a]	capacity factor	annual output (kWh/kW-yr)	cost of incentive (¢/kWh)
FC-R	4500	675	60%	5256	12.8
PV	3500	525	20%	1752	30.0
WD	1500	225	20%	1752	12.8
FC-NR	2500	375	60%	5256	7.1
ICE-R	1000	150	40%	3504	4.3
MT-R	1000	150	40%	3504	4.3
GT-R	1000	150	80%	7008	2.1
ICE-NR	600	90	40%	3504	2.6
MT-NR	800	120	40%	3504	3.4
GT-NR	600	90	80%	7008	1.3

[a] For 2005 incentives only and assuming a 15% fixed charge rate

Prior Assessment Efforts

The first industry-wide assessments of self-generation opportunities were carried out in the early 1990s by Rumla, Inc. as part of the Electric Power Research Institute's (EPRI) effort to investigate the economic feasibility of DG technologies.[11] The focus of the EPRI-sponsored studies and similar projects was to identify and evaluate the cost effectiveness of high-value applications of DG options including customer-owned systems.[12] The approach used was to: (1) work with utility engineers to locate the best placements for the candidate technologies within the network; and (2) assess the costs and benefits of each application with specific emphasis on generation and T&D upgrading investment deferral savings. Generation benefits were estimated in terms of the avoided costs of a proxy generation investment (normally a combustion turbine (CT) and a natural gas fired combined cycle combustion turbine (NG CCCT) plant for valuing firm energy and capacity contributions). This technique was borrowed from the approach developed for determining avoided cost payments to California's Qualifying Facility (QF) owners. Potential T&D deferral savings were determined in terms of the value of delaying commitment of capital to planned or contemplated T&D upgrades that can be pushed back with the introduction of a local generator. Although good-investment candidates were identified at the distribution and sub-transmission networks, none were found at the transmission level.

[11] The studies involved more than 25 utility systems in almost every region of the U.S. and covering fuel cells, ICEs, gas turbines, PV systems and batteries.

[12] Non-EPRI studies were also carried out by Rumla for utility clients in major metropolitan areas.

A more recent effort carried out by Energy and Environmental Economics (E3) on behalf of the CPUC led to a methodology for estimating the benefits of energy efficiency programs. The CPUC adopted the E3 tool for planning energy efficiency investment programs on an interim basis. There were also calls for extending the methodology to other applications including DG and self-generation investments and QF proceedings.

Aside from assessing environmental benefits and a few peripheral energy-related savings, the main thrust of the E3 methodology was the estimation of the avoided energy commodity values and the T&D investment-deferral savings. The approach used for valuing the generation is the familiar proxy technique. The E3 proxy was divided into two parts. The first took the form of the cost of wholesale bulk-power traded from the implementation date of the energy efficiency investment till the emergence of a load-resource imbalance. The power trading proxy allowed energy values to be differentiated into two locational components: the North-of-Path 15 (NP-15) and South-of-Path 15 (SP-15) pricing zones established by the California Independent System Operator (CAISO) in 1998. The second part was based on the NG CCCT plant proxy. This method produced, essentially, a California-wide uniform energy price.

For the T&D savings, the E3 methodology estimates the value of deferring planned T&D investments in proportion to expected reductions in peak loads due to energy efficiency implementation. A complex process is used to allocate geographically the projected savings among temperature-based climate zones coinciding with the IOUs' T&D planning areas. The combinations of energy commodity values and climate-zone specific T&D deferral benefits produced area and time differentiated avoided cost values attributable to future energy efficiency programs implementation.

Need for a New Approach: Proposed Methodology

A sound approach for assessing the grid impacts of SGIP investments must meet three basic criteria:

- The focus has to be on the generation and distribution components of electric power service.
- The approach must include a methodology that can assess self-generation performance in the future in accordance with the market structure and rules expected to prevail.
- There should be a diligent effort to achieve the highest practicable spatial resolution of information on the costs and benefits of the SGIP investments of interest.

Prior efforts have more or less recognized the importance of the generation factor. But with respect to distribution system benefits, the notion of transmission investment deferability continued to detract from the more realistic benefits associated with low-voltage opportunities. The achieved level of penetration of self-generation under the SGIP is simply too low and too dispersed to be credibly tied to any past or future deferral of transmission upgrades.

The E3 methodology is probably the most comprehensive of past efforts in California. However, the treatment of the core benefits associated with potential electric commodity and distribution system savings does not meet the requirements laid out here for proper evaluation of SGIP investments. Specifically, as stated before, the value of generation in the future is based on the NG CCCT power plant proxy. This method does not meet the second criterion; namely, conformity with the market structure and rules to be implemented in the very near term. Using the zone-specific market trading proxy to differentiate NG CCCT-based prices into NP-15 and SP-15 prices does not remedy the situation. To demonstrate this point, we gathered a record of energy transactions carried out from January 1, 2002 through October 3, 2008 courtesy of the Intercontinental Exchange. The assembled information was then condensed into the 2002 through 2008 monthly average settlement prices presented in Table 19 for the NP-15 and SP-15 Zones, respectively. These values were subsequently used to derive the monthly price differences between the two zones for the same set of years. The results indicate minimal price differentiation (as shown in the columns labeled "Δ" in Table 19). On an annual basis, the deviations average 0 to -1 dollar/MWh. Carrying out such miniscule price differences into the future is clearly unrealistic.

Table 19. Monthly Wholesale Electricity Prices ($/MWh)

	2002			2003			2004			2005			2006			2007			2008+		
	N	S	Δ	N	S	Δ	N	S	Δ	N	S	Δ	N	S	Δ	N	S	Δ	N	S	Δ
January	22	22	0	40	40	0	46	46	0	53	52	1	57	57	0	59	59	0	71	70	1
February	24	23	1	55	57	-2	46	46	0	49	49	0	52	52	0	58	56	2	64	62	2
March	34	34	0	54	53	1	40	43	-3	51	52	-1	47	48	-1	53	56	-3	55	58	-3
April	28	28	0	42	43	-1	41	44	-3	54	54	0	44	48	-4	59	60	-1	63	65	-2
May	25	26	-1	37	41	-4	53	52	1	47	47	0	42	45	-3	63	62	1	64	65	-1
June	25	26	-1	41	44	-3	50	49	1	44	45	-1	46	48	-2	73	72	1	72	71	1
July	31	30	1	51	51	0	51	52	-1	63	58	5	82	71	11	57	65	-8	80	78	2
August	26	28	-2	46	48	-2	57	58	-1	73	74	-1	60	59	1	61	59	2	77	75	2
September	31	31	0	45	45	0	47	45	2	83	84	-1	44	44	0	55	56	-1	66	67	-1
October	33	33	0	42	44	-2	46	45	1	91	88	3	54	55	-1	62	60	2	77	75	2
November	37	37	0	39	38	1	63	57	6	78	84	-6	62	62	0	62	65	-3	78	81	-3
December	42	41	1	46	45	1	60	59	1	100	93	7	58	57	1	65	65	0	81	79	2

N=Average NP-15 Trading Prices, S=Average SP-15 Trading Prices, Δ=Average NP-15 Prices Minus SP-15 Prices

Note: Prices are based on the Intercontinental Exchange

The need for a methodology that allows greater spatial resolution of electricity commodity prices is made more compelling by the fact that the CAISO plans to implement a new market platform based on the concept of locational marginal prices (LMPs) within the next few months. The new structure and rules, dubbed the Market Redesign and Technology Update (MRTU) project will bring radical changes in the determination of energy commodity prices and associated cost of service charges. The new regime will sharply increase the degree of geographic resolution from the three pricing zones currently in use to bus-specific (nodal) prices at more than 3,000 locations.[13] Moreover, the nodal LMPs that CAISO plans to use for transactions scheduling and settlements will account for location-specific marginal losses as well as congestion costs. While transmission congestion may not be manifested at all times, the ubiquity of marginal loss differences among buses will ensure virtually continued spatial price variation over the CAISO territory.

The approach recommended here for assessing the impacts of self-generation on the grid consists of five steps:[14]

1. Identify the relevant impacts;
2. Disaggregate them by the different applicable perspectives;
3. Reduce the identified impacts to those to be assessed from a societal (California) perspective as required for this study;
4. Qualitatively compare the potential magnitudes and ease of assessment of the impacts identified in Step 3; and
5. Estimate the most significant of the impacts on the basis of Step 4 in a manner that can enable the formulation of more efficient public policies and State incentive programs for self-generation and related/similar technologies.

Firstly, a revisit of Table 2 is necessary, which lists the cost and benefit elements of DG installations of the SGIP for participants, non-participants, and society (represented here as California). The displayed information meets the requirements of both Steps 1 and 2. The table also shows that some of the effects of self-generation can change sign when viewed from a different perspective. For example, what might be a cost for non-participants can be a benefit for participants. This type of impact asymmetry is useful when the two perspectives are merged to create a combined societal point of view because some costs and benefits cancel out; resulting in a less burdensome analysis.

For the purposes of this section, the rest of the discussion will be limited to the potential benefits to society of DG installations of the SGIP. Cost issues are dealt with elsewhere in this report.

The grid impacts analysis focused on the following areas:

- Avoided energy costs;
- Transmission congestion mitigation; and
- Potential electric distribution system savings.

The objectives of this approach are to develop a sound and robust methodology for assessing these benefits and to use the methodology to estimate the value of self-

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[13] In addition to NP-15 and SP-15, CAISO has added a smaller pricing zone named ZP-26.

[14] As discussed further in this section, the developed assessment approach and methodology must be applicable seamlessly to other market segments and public investment programs such as energy efficiency, distributed generation, Qualifying Facility industry, and utility generation and independent power investments.

generation investments. Assessing grid benefits must meet three basic requirements:1) It has to evaluate SGIP performance both retrospectively and prospectively; 2) It should simultaneously and seamlessly address market realities at two levels: a) Local distribution (delivery); and b) Bulk-power (generation and transmission); and 3) It must be sufficiently comprehensive and robust to be applicable to other technologies and programs.

The SGIP period of interest involves generators installed in 2002–2006. Assuming a 30-year life span stretches the study period from 2002 through 2036. Consequently, SGIP performance assessment would have to cover to consist of two parts: 1) A retrospective evaluation covering the period 2002 – 2008; and 2) A prospective assessment for 2009 – 2036.

These two time windows happen to coincide with a long expected change at the end of this year in market design at the bulk-power level; namely, the implementation of bus-level management of power generation scheduling and trading transactions and settlements by the California Independent System Operator (CAISO). The new regime, the previously discussed MRTU, will replace the current zonal pricing market platform (which divides California into three zones of flat prices) with a nodal pricing system consisting of over 3,000 bus-specific LMPs. The expected significant switch in 2009 from zonal to nodal pricing requires the development of two distinct methodologies for assessing the benefits of self-generation: a retrospective one for the period 2002–2008 and a prospectively focused version for 2009–2036.

Figure 5 outlines the methodology developed to assess the SGIP grid benefits between a) 2002–2008 and b) 2009–2036. The SGIP grid impacts evaluation process starts with the retrospective analysis as follows:

In Step 1, the self-generators geographic locations, nameplate capacity ratings and hourly production profiles are identified. In this first step, Rumla ascertained the availability of adequate and reliable data to construct a typical year of hourly outputs for each generator. Only the cases with sufficient and consistent information are examined further.

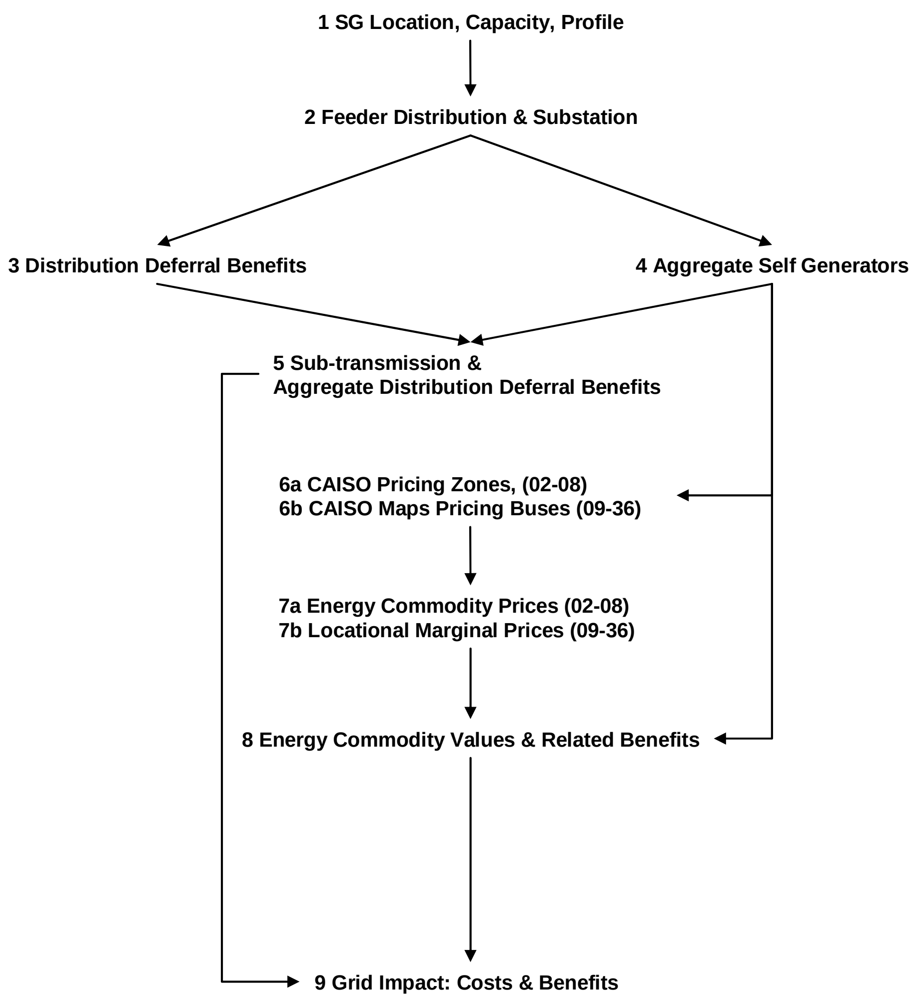
In Step 2, Rumla identified the point of interconnection with the electric utility serving the owner (location) of the self-generation facility with assistance from the utility's distribution planning and operation engineers. The required information includes the identifiers, kVA nameplate ratings, summer capability ratings, operating voltages, and the last five years of recorded summer peak loadings for the secondary and primary feeders and transformers as well as the substation banks ultimately serving the self-generation customer.[15]

In Step 3, Rumla assessed the potential role of each self-generation facility in deferring the need to upgrade the distribution system elements to which the SGIP participant and its generator are immediately interconnected. This step involves comparison of the

[15] Self-generating customers may still rely on the utility to serve part of their loads and to provide standby power.

peak-demand loading of the circuits and transformers serving the customers in the absence of the generator with their allowable maximum loadings (overloading capabilities). Any year in which the peak-demand loading of a distribution element is deemed likely to exceed its maximum overloading capability in the absence of the generator under consideration counts as one year of potential upgrading deferability.[16] Because the retrospective analysis covers 2008, this part of the methodology involves forecasting circuits peak-demand loading for at least one year.[17]

Figure 5. (a) Retrospective and (b) Prospective Methodology to Assess Grid Impacts



In Step 4, the self-generators are aggregated. This step is necessary to evaluate both the energy commodity savings and potential deferral of distribution system upgrades.

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[16] The finding in such case is considered potential rather than a certainty because utility engineers may have other solutions to the overloading problem and the generator may not be available during local peak periods.

[17] In some cases there were gaps in utility data on historic loads.

For the former, the aggregation has to be carried out on a zip-code basis.[18] For the latter, it should be performed along the secondary circuits first and then up the voltage chain through the primary feeders to the transformer bank(s) of the distribution substation serving the area hosting several SGIP applications. The end result of the zip-code aggregation is a typical year of hourly generation output representing the combined production profiles of all the self-generators located in the zip code(s) under consideration.

In Step 5, Rumla assessed the potential role of aggregates of self-generators in deferring the need to upgrade primary feeders, distribution substation transformer bank(s) and/or radial sub-transmission circuits. This task requires information developed in Steps 3 and 4.

In Step 6, the pertinent CAISO pricing zones are identified. There are three zones to consider: NP-15, SP-15 and ZP-26. Information on market transactions is limited to NP-15 and SP-15. Hence, ZP-26 will not be considered any further. Determining which zone a generator or a group of generators belongs to is accomplished by zip code matching.

In Step 7, the electricity commodity prices are determined. Since the demise of the California Power Exchange as the market maker, the only sources of information on commodity prices are commercial market data services such as the Intercontinental Exchange. The Intercontinental Exchange tracks and maintains detailed information on daily wholesale power trades within NP-15 and SP-15. The historic records, which are identified for each day and each zone as off-peak and on-peak transactions, include the dates, the low, high and average settlement prices and the number of trades concluded. Intercontinental Exchange data can be used in the absence of utility information on the historic costs of its power purchases to meet its load service obligations.

In Step 8, the energy commodity values and related benefits are estimated. The outcome of this step does not concern SGIP participants because a self-generator will not be charged for the cost of generation the utility will not be providing. As for non-participants, the effects of displacing utility procurement with self-generation is indirect and probably minor under the current market design and in light of the small volume of the self-generation fleet at this time. The concern in this step is over whether society as a whole would be better or worse off as a result of a participant's election to self generate. To settle this issue, market (Intercontinental Exchange-based) prices are assigned to each generator to determine net cost or benefit to society with the help of the following simple equation:

$$\mathrm{SEPI} = (\mathrm{ICECP} - \mathrm{SGCE}) \times \mathrm{SGO} \qquad (1),$$

Where SEPI is the Society Energy Price Impact, ICECP is the Intercontinental Exchange-based Commodity Price, SGCE is the Self-Generation Cost of Energy, and

[18] As noted in the description of the prospective methodology, the zip-code aggregation can proceed further by combining generators from more than one zip code area.

SGO is the Self-Generation Output. Note that according to Equation 1, society may come out ahead when it is a seller's market (i.e., periods of perceived supply shortages) but may lose in a buyer's market.

In Step 9, the grid impacts i.e., costs and benefits are determined. The last step combines the results of Steps 5 and 8 into an overall net cost or benefit to non-participants and to society as a whole.

The first five steps in the methodology developed to evaluate the SGIP grid impacts over 2009–2036 are the same as the ones described in conjunction with the retrospective assessment. Therefore, the following discussion is limited to Steps 6 through 9.

Step 6 is for identifying CAISO's relevant generation buses. Beginning in 2009, the CAISO will be posting hourly bus-specific prices for every generating unit under its control. Simulations of grid operation have shown wide variations in LMPs within a single pricing zone. Spatial price dispersion reflects locational differences with respect to transmission congestion and marginal transmission losses. Capturing such variations is essential to proper evaluation of self-generation investments and henceforth the design and assessment of self generation incentive programs as well as other programs intended to promote distributed energy resources (DERs). To accomplish this goal Rumla paired each self-generation cluster constructed in Step 5 with the nearest large generating unit listed in the WECC/MAPS database using a zip-code search techniques.[19] Once a match is found the self-generation cluster is assigned the same bus designated to the neighboring large power plant. This step required identifying 94 buses to electrically anchor 94 self-generation clusters as miniature satellite generators. Note that the principle underlying this method is the geographic equivalency of two sources of energy: in the absence of differences due to transmission congestion and/or marginal losses, the market value of the electric commodity is the same.

Step 7 involves determining electricity commodity prices. With the anticipated implementation of the MRTU and its LMP market platform, one must use a security-constrained economic dispatch model. A security-constrained economic dispatch tool can determine future LMPs while accounting for transmission constraints and marginal losses. The model employed was GE's MAPS software. Because of the voluminous data generated by the model, the simulations were conducted every other year, starting with 2009 and ending with 2017. Prices for the period 2018 through 2036 can be derived by trending techniques.

Step 8 is for estimating energy commodity values. As stated earlier, this step is concerned with the impacts of self-generation on society. However, because the new market pricing regime promises to unbundle wholesale prices into three components, there is an opportunity to determine further the attainability of additional benefits.

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[19] MAPS is the simulation model used to emulate system operation as described in Step 7.

Equation 2 provides a means to measure the overall impact of self-generation on society:

$$\mathrm{SEPI} = (\mathrm{SGLMP} - \mathrm{SGCE}) \times \mathrm{SGO} \qquad (2),$$

Where SGLMP is Self-Generator LMP, and the remaining terms are the same as defined previously in Equation (1). Since each LMP consists of a commodity, congestion and marginal losses components, we can determine the extent to which transmission-related costs influence the outcome of Equation (2).Step 9 assesses grid impact costs and benefits. Although it is similar to the one in the retrospective analysis, the availability of price dispersion information and the ability to unbundle a price into three components allows a more thorough evaluation of the impacts.

CHAPTER 3: Results

Environmental Impacts

The environmental benefits of the program are small in terms of air quality and climate change benefits; however, this is a reflection of the current SGIP resource mix and the relatively small capacity of installations. The air quality pollutant (dis)benefits are shown in Table 20, with values shown in (short) tons for VOC, NO_x, CO, and PM2.5. The GHG reduction (dis)benefits of the SGIP are shown in Table 21 – GHG emissions are reported in million metric tons (MMT).

With the exception of PM2.5, the installations inter-connected prior to the cutoff date account for a small increase in air quality pollutants. Note that ICE installations using a non-renewable fuel (ICE-NR) account for over 99 percent of the increases in emissions of VOC and CO, and more than 80 percent of the increase in emissions of NO_x.

With respect to GHGs, the installations yield a small net decrease. As noted previously, these (dis)benefits are partly a function of the selected baseline to calculate the differential emissions, defined here as power plants using NG CCCTs. These plants are efficient and burn cleanly. It is possible that the emission benefits of the SGIP are better than those indicated here if marginal power generation includes dirtier ‘peaker’ plants. That said, it is also reasonable to assume that the benefits could decrease if a baseline was used that represented the RPS. One can argue that the marginal power generation should be a mix of power plants using NG CCCTs and renewable power generation sources that the IOUs are required to procure as part of the RPS.

In both the case of air quality pollutants and GHGs, the reductions represent only a fraction of a percent of the statewide inventory of each pollutant. For instance, VOC, NO_x, and CO are emitted statewide at a rate of 2,300, 12,500, and 3,600 tons *per day*, respectively (CARB 2007). If the 30-year cumulative emissions are normalized to daily emission rates, it is estimated that these technologies will cumulatively emit 0.7, .0.4, and 1.8 tons per day. In each case, the emissions represent less than 5 thousandths of a percent of the state total. The Energy Commission has estimated that as of 2004, California was emitting roughly 500 MMT of CO_2-eq on an annual basis. The SGIP emission reductions total 0.62 MMT on a cumulative basis, or 0.02 MMT on an annual basis. The GHG reductions can largely be attributed to solar PV installations (70 percent), whereas renewable fueled engine and turbine technologies account for 24 percent of the reduction, and FCs account for the remainder (6 percent).

As of today, the environmental impacts of the SGIP are small. For the sake of simplicity, consider the SGIP moving forward with limited or no technological advances. Furthermore, assume that the resource mix of the SGIP is limited solely to clean, renewable, or renewable-fueled power generation technologies:[20] ICE-R, MT-R, FC-NR, FC-R and WD. At its current rate, the SGIP needs to expand by more than two

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[20] With the exception of PV technologies, for which incentives are now administered by the California Solar Initiative.

orders of magnitude, or roughly 170 times to reduce CO_2-eq in California by 1 percent (assuming

Table 20. Air Quality Pollutant Emission Impacts of the SGIP (cumulative short tons)

	PG&E				SCE				SCG				SDGE				Total			
	VOC	NOx	CO	PM2.5	VOC	NOx	CO	PM2.5	VOC	NOx	CO	PM2.5	VOC	NOx	CO	PM2.5	VOC	NOx	CO	PM2.5
PV	-2	-11	-157	-15	-1	-4	-56	-6	-1	-2	-32	-3	-1	-3	-43	-4	-5	-21	-287	-28
ICE-NR	3123	1464	7798	-62	1411	664	3530	-28	2661	1244	6615	-55	605	282	1500	-13	7799	3654	19443	-157
ICE-R	-3	-14	-58	-6	-1	-7	-30	-3	-1	-4	-15	-1	0	0	0	0	-4	-25	-103	-10
MT-NR	10	17	-70	-6	6	11	-31	-3	6	4	-70	-7	2	5	-4	-1	24	38	-175	-16
MT-R	-2	-12	-40	-4	-2	-9	-29	-3	0	0	0	0	-1	-5	-16	-1	-4	-25	-85	-8
FC-NR	-3	-76	-17	-7	0	-12	-2	-1	-1	-32	-7	-3	-1	-32	-7	-3	-6	-152	-34	-14
FC-R	0	0	0	0	0	-5	-1	-1	0	0	0	0	0	0	0	0	0	-5	-1	-1
GT	4	239	251	-3	0	0	0	0	4	268	281	-4	4	271	283	-4	13	778	815	-11
WD	—	—	—	—	—	—	-4	—	—	—	—	—	—	—	—	—	0	0	-4	0
Total	**3127**	**1681**	**7676**	**-98**	**1412**	**653**	**3374**	**-43**	**2668**	**1516**	**6734**	**-73**	**608**	**556**	**1682**	**-26**	**7823**	**4407**	**19426**	**-243**

Table 21. GHG Emission Impacts of the SGIP (in cumulative million metric tons, MMT)

	PG&E	SCE	SCG	SDGE	Total
PV	-1.14	-0.41	-0.23	-0.31	-2.09
ICE-NR	0.67	0.31	0.54	0.12	1.64
ICE-R	-0.24	-0.13	-0.06	0.00	-0.43
MT-NR	0.19	0.11	0.11	0.04	0.45
MT-R	-0.12	-0.09	0.00	-0.05	-0.26
FC-NR	-0.07	-0.01	-0.03	-0.03	-0.13
FC-R	0.00	-0.02	0.00	0.00	-0.02
GT	0.08	0.00	0.09	0.09	0.26
WD	—	-0.03	—	—	-0.03
Total	-0.63	-0.27	0.41	-0.13	-0.62

Note: In the event that a column does not sum to 100 percent, it is a function of rounding and not a calculation error

2004 as a baseline year). Even with considerable technological breakthroughs, this value is unlikely to decrease much below two orders of magnitude.

Macroeconomic Impacts

The results of the IMPLAN analysis suggest that every dollar spent on project capital, operation, and maintenance costs in the SGIP resulted in between $0.60 and $0.66 in value added economic activity within the state of California. In total, the net present value of expenditures for SGIP installations between 2001 and 2006, $2.6 billion, resulted in between $1.6 and $1.7 billion of value added benefits to the state. Value added refers to value gained from using a product in a new way. For example, a steel mill adds value when it decides to produce finished products, rather than selling all of its production as raw material. To estimate the value added benefits of a steel mill, the difference in the value of the raw metal compared to the finished metal, minus the costs associated with the finishing process can be calculated.

Other positive economic benefits of the program are the creation of between 14,090 and 15,467 full time equivalent (FTE) worker years over 30 years that result in $765 to $855 million in employee compensation. FTE represents the number of total hours worked divided by the maximum number of compensable hours in a work year. For example, the work year is typically defined as 2,080 hours, so one worker occupying a paid full time job all year would consume one FTE. Two employees working for 1,040 hours each would consume one FTE between the two of them.

The macroeconomic analysis results generated by IMPLAN are provided with a RPC sensitivity analysis in Table 22. The RPC sensitivity analysis demonstrates how the results would vary when using IMPLAN's California specific default RPC value of 84 percent and a TIAX suggested value of 50 percent for Semiconductors and Related Device Manufacturing (IMPLAN sector 311).

Table 22. Gross Measures of Macro-Economic Impacts (millions $2006)

		RPC	
		84% (default)	50% (adjusted)
Costs	Total Project Costs	2,627	2,627
Benefits	Total Output	3,541	3,181
	Total Value Added	1,723	1,582
	Total Employment (FTE)	15,467	14,090
	Total Compensation	855	765
Total Value Added / Total Project Costs		0.66	0.60

Note: Total Output is equal to the sum of Total Project Costs and Total Value Added.

The results presented above are the gross macroeconomic benefits of DG; however, as pointed out by members of the utility industry "the macroeconomic benefit would be a comparison of the impact of new SGIP technology versus the impact of existing or new central station technology (Orozco 2008)." The question to be asked is: what are the net macroeconomic benefits that result from moving from central station generation to DG? The utility industry points out that "Such a macroeconomic benefit would occur only if 1) the DG technology has a higher likelihood of using resources made in California than conventional generation, or 2) the DG technology leads to more spending in California than would have otherwise occurred based on utility customer spending patterns."

In a letter submitted by SDG&E and SCG to the Energy Commission (Orozco 2008), they stated that "DG technology would avoid the conventional central station gas-fired generation." This comment suggests that the shift to DG merely replaces one kind of generating facility for another. However, this statement may reflect California's substantial imports of electricity, reliance on out-of-state natural gas, and substantial differences in construction and equipment purchasing patterns between DG and central station facilities.

One observation is that DG replaces imported electric power. Imported electric power results in dollars being sent out of the state and provides no macroeconomic benefits to Californians. For example, in 2007, approximately one-third of the electric power consumed in California was imported.[21] Note that if California power demand were to be reduced, in-state utilities may reduce their electric imports rather than shutting down their own plants. It is therefore likely that DG will replace imported electricity and in turn provide positive macroeconomic impacts to California.

Even if some percentage of DG power will replace in-state conventional central station gas-fired generation, DG power will still provide macroeconomic benefits by reducing imported natural gas. For example, SDG&E and SCG state that:

> "Where generation costs are avoided, the net macroeconomic benefit would depend on the percentage of construction-related demand for goods and services in California related to the DG technology compared to conventional generation. The bottom line is that the macroeconomic benefit will depend on numerous assumptions about where the primary components of the technologies are manufactured: central station gas-fired generation equipment versus the DG technology. The location of such manufactured products is highly speculative without the SGIP subsidies being contingent on the use of California manufactured goods."

This analysis focuses only on "construction-related demand for goods and services." However, a large component of electric generation costs for conventional central station gas-fired generation is the cost for fuel, as opposed to construction-related goods and services. While there may be uncertainty as to where each power plant's components are made, it is clear that California cannot produce enough natural gas to meet its in-state needs and must import gas to fuel marginal electricity production. The dollars spent on this imported fuel is money sent out of the state providing no macroeconomic benefits to California. This compares to a DG program in which less than 25 percent of incentive payments went to facilities that were designed to use nonrenewable energy sources.

Only after accounting for the dollars sent out of state for purchased electricity and natural gas should the analysis examine whether "construction-related demand for

[21] California Energy Commission, Energy Almanac, 2007, "Total Electrical System Power" http://www.energyalmanac.ca.gov/electricity/total_system_power.html
According to the Energy Commission, California's total electrical system power was 302,072 GW in 2007 and 31 percent of the state's electrical energy is imported from outside the state.

goods and services" is supplied by sources that benefit the California economy. To examine this issue, it is important to focus separately on the construction of the facilities and the installation of the generating equipment as opposed to the purchase of the generating equipment itself.

A total of 1,062 DG installations were constructed between 2001 and 2006 at a cost of $1.3 billion. Accordingly, the average capital cost was $1.3 million per installation. For the average DG facility, about $57,500 was spent on architectural and engineering costs and about $325,000 was spent on the facility construction and equipment installation.[22] Note that even these costs were typically divided among several firms and subcontractors. Projects of this magnitude are more likely to be performed by in-state firms than large central station power plant construction projects that generate many times more energy than the typical DG facility. For example, the costs of large central station power plants are estimated using information from a 2002 report by the Northwest Power Planning Council (Council 2002).[23] The NG CCCT power plant described in the report is a General Electric 7FA natural gas turbine generator with a baseload capacity of 540 MW, which is about 2,200 times larger than the capacity of an average DG installation. The development and construction cost for the NG CCCT power plant is estimated to be $352 million.[24]

To improve estimates of the macro-economic impacts of the SGIP further, it would be worthwhile to collect data on power plants that California utilities have constructed in the recent past. These data would include the locations of the firms that constructed the power plants, the dollar amounts of the contracts and the place or residence of the workers that were employed. This information would be useful to compare to similar data for DG facilities.

The second part of the construction-related demand is the cost of the generating equipment such as turbines, PV panels, and ancillary equipment e.g., piping, heat exchangers, metering switchgear, data acquisition equipment, and air emission control equipment. Each of these systems at the DG facility are smaller in size and therefore just as likely if not more likely to be produced or at least distributed by a Californian firm.

This brings up and even more important point: California leads the nation in developing innovative energy and environmental solutions such as DG. As such, the development of a local market for construction, installation and production of DG technologies will

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[22] Capital costs associated with architectural and engineering services, IMPLAN sector 439, was $61 million for the entire SGIP. Capital costs associated with construction services, IMPLAN sectors 41, 45, and 205, totaled $318 million.

[23] The report states, "The Council may also use these assumptions in the assessment of other issues where generic information concerning natural gas combined-cycle power plants is needed." The report includes an important warning that while the intent of the report is to characterize a facility typical of those likely to be constructed by the Council in the near future, "each plant is unique and that actual projects may differ from these assumptions."

[24] The Northwest Power Planning Council report provides a development and construction cost of $565/kW in 2002 dollars for a combined-cycle gas turbine power plant. Using the Bureau of Labor Statistics' producer price index for finished goods this value can be expressed as $652/kW in 2006 dollars. The Council's report uses a 540 MW (i.e. 540,000 kW) generator. Accordingly, development and construction of a plant using this generator will cost about $352 million.

give the state a head start in developing a DG planning, construction and equipment industry. As other states and countries follow California's lead in implementing DG, they will look to California firms for planning, equipment, technology and installation. As a result, the macroeconomic effects of DG spending in California may actually be many times larger than the direct spending on the initial program analyzed in this report.

Utility Customer Spending Patterns

The utility comment also states that:

> "If the DG technology is more expensive that [sic] the central station technology or it is simply reducing existing generation, any calculated benefit would have to be offset against the negative impact of higher electricity rates reducing disposable income of non- participating utility customers. If subsidies are provided, then there is a reduction in purchased power among the non-participating utility customers. To properly evaluate the macroeconomic costs of the higher utility rates would require an analysis of how Californians would likely spend the added disposable income if not for the DG subsidies and what percentage would be spent on goods and services produced in California. While the IMPLAN input-output model may be capable of producing a result, the numerous technical assumptions and very large data requirements make the exercise open to manipulation. The results of the analysis will hinge on speculation on the degree of agglomeration of DG supply industries in California versus conventional technology or general consumption. In the final analysis, consumer groups will argue the rate increases will have a larger, negative impact on California than the positive macroeconomic benefits provided by the DG; while DG proponents will argue the opposite."

It is not the purpose of the macroeconomic modeling to analyze which technology is more expensive; there is clearly not a simple answer to the question regarding the macroeconomic impacts of the SGIP. On the other hand, the macroeconomic model can be used to examine the impacts on the California economy of a dollar spent by consumers versus a dollar spent on DG.

The IMPLAN model provides detail on the purchase patterns for nine California household income levels (as personal consumption expenditures). These expenditure patterns were aggregated based on the amount of electricity spending by each income class. This expenditure pattern was then run through the model to estimate the resulting value added occurring in California. This result was then compared to the value added captured in California by spending on DG.

The results are shown in Table 23. Spending on distributed generation results in higher output than personal consumption by just over 5 percent. However, it results in 13.5 percent less value added and 9.4 percent less employee compensation. However, it does result in jobs that average 44.5 percent higher compensation. In general, the diversion of funds to or from distributed generation from the general ratepayer will have only a marginal impact on the California economy.

Table 23. Household Expenditure verses SGIP Expenditures, per $100 million (millions $2006, except Employment in FTE)

	Household	DG capital + O&M	% difference (DG/Household)
California Total Output	128	134.8	+5.3
California Total Value Added	75.8	65.6	-13.5
California Total Employment (FTE)	938.7	588.8	-37.3
California Total Compensation	35.9	32.5	-9.4
California Compensation per FTE	38,251	55,271	+44.5

In the comments by SDG&E and SCG it is stated that “any macroeconomic benefits [of DG] are small and highly speculative and should not be included in the cost benefit framework.” However, the analysis here suggests that the DG facilities built will produce $1.6 to $1.7 billion in value added benefits to the California economy. Furthermore, in the absence of the SGIP, the majority of the value added benefits would be lost to the state, as this electric energy would likely have been purchased from outside the state or would have been produced from existing plants using natural gas purchased from outside the state. Even where DG facility construction, replaces construction of conventional central station construction, value added benefits captured by the California economy are likely to be higher as the much smaller size of these facilities favors the use and growth of local Californian firms and workers. Even in the case where DG diverts ratepayer spending, there is no evidence that this reduces value added benefits to California.

Grid Impacts

Energy Commodity and Related Impacts

Table 24 and Table 25 list the monthly average prices for electric energy traded in the on-peak and off-peak hours in NP-15 and SP-15 for 2002 through 2008, respectively. These Intercontinental Exchange-based estimates tend to be lower than the average cost of generation for IOU customers. For example, according to and Table 25, the average price of traded power over 2007–2008 is roughly 6.6 cents per kWh. This value is barely 52 percent of the average cost of generation for the IOU residential customer represented in Table 17. Such a gap in the cost of energy is indicative of a legacy of high-cost resources for utility customers. Assuming a kWh not served means a kWh less of energy purchases at the utility’s average cost of generation implies indifference for non-participants and the situation reduces to Equation (1) for society as a whole.

Table 26 summarizes the results of simulating market operation under the MRTU as of 2009. Because the simulation assumes perfect competition (i.e., generators are either bidding at their true marginal costs of production or are price takers), the displayed results are probably on the low side. However, the important story is the obvious prevalence of spatial price dispersion. And because dispersion is measured in terms of observed price differences, the effects of the perfect competition assumption are not worrisome. The frequency of significant locational price variation among the 94 clusters of self-generation is evident from Figures 7-11 (for the years 2009, 2011, 2013, 2015 and 2017). The displayed dispersions indicate the prevalence of marginal losses and the frequency of transmission congestion. For example, there is a virtually ubiquitous price delta of $15-$20 per MWh. This gap indicates the presence of significant marginal losses.

Locational variation in prices means opportunities for cost effective investments in self-generation and other forms of DERs. For instance, if Location A is assigned a price of $70/MWh and Location B is given a price of $55/MWh, encouraging SGIP projects at Location A is more effective than the other way around. Table 27 provides a hypothetical illustration of the value of commodity price differentiation for the SGIP. For example, depending on the discount rate used, a $20/MWh commodity price gap could translate into a benefit of $1.2 to $3.5 per Watt. This locational advantage can offset most of the SGIP payments described in Table 18.

Identifying high-value (i.e., high LMP) areas for preferential SGIP support can yield significantly higher return on investment than programs designed around temperature-based climate zones for the following reasons:

- Targeting congestion zones will benefit non-participants in two ways:
  - There will be less load to haul energy for, to a constrained area, at potentially high transmission congestion charges; and
  - With sufficient density, self-generation may prevent congestion for the rest of the utility's load in the susceptible area (i.e., non-participants); and
- Because climate zone-based investments are concerned with reducing (deferring) distribution system upgrades, they are limited by definition to a smaller target.[25] As demonstrated by Table 17, the distribution component of service accounts for only 3.8 cents/kWh (19 percent) for a residential customer. The energy portion of the same bill commands 65 percent of the total. And according to Table 26, the average spread for SGIP nodal prices is around 2.4 cents/kWh for 2009. It is doubtful that deferring distribution system upgrades could offer similar opportunities.

[25] Proponents of this strategy often include transmission in their plans. In reality, deferring high voltage projects with DR investments remains a theoretical concept.

Table 24. NP-15 Monthly Trading Prices [a]

	Average Off-Peak Trading Prices ($/MWh)[b]								
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2012**	**2017**	**2022**
January	18	32	39	44	48	47	80	107	135
February	20	47	41	41	48	52	82	108	134
March	30	44	35	41	40	45	72	93	114
April	20	34	35	45	29	41	82	112	143
May	17	25	43	36	23	48	86	121	156
June	15	24	36	27	21	47	67	92	117
July	17	41	41	41	45	45	90	124	157
August	20	38	46	52	50	41	80	105	131
September	25	37	38	66	41	42	68	86	104
October	25	34	36	79	35	44	67	85	102
November	31	32	51	66	49	52	84	109	134
December	34	38	50	91	54	53	93	120	146

	Average On-Peak Trading Prices ($/MWh)[c]								
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2012**	**2017**	**2022**
January	24	44	50	58	61	65	111	152	192
February	25	59	49	53	55	61	99	130	161
March	36	58	43	56	50	57	98	128	159
April	31	46	44	59	52	69	116	159	201
May	29	43	58	52	52	71	116	158	200
June	30	50	56	52	59	86	152	213	275
July	37	55	57	75	101	64	126	167	208
August	29	50	62	84	65	70	108	141	173
September	35	49	51	91	46	61	87	108	129
October	37	46	51	96	64	71	117	155	193
November	40	42	69	84	68	67	111	143	176
December	46	50	65	104	61	71	108	136	164

[a] Based on data obtained from the Intercontinental Exchange, October 2, 2008.

[b] Off-peak means Monday through Saturday 10 p.m. to 6 a.m. and Sundays and holidays.

[c] On-peak means Monday through Saturday 6 a.m. through 9:59 p.m.

Table 25. SP-15 Monthly Trading Prices[a]

	Average Off-Peak Trading Prices ($/MWh)[b]								
	2002	2003	2004	2005	2006	2007	2012	2017	2022
January	18	30	37	44	50	47	80	109	138
February	20	46	40	40	48	52	81	108	134
March	30	43	35	41	41	46	72	94	115
April	20	33	35	45	34	40	82	112	142
May	17	26	41	38	29	47	88	124	160
June	12	24	34	27	21	47	69	96	124
July	16	41	40	41	44	46	91	125	158
August	19	38	44	52	51	41	81	108	134
September	23	36	33	65	41	43	71	91	112
October	24	33	32	78	34	44	67	85	103
November	29	29	45	66	49	52	87	115	143
December	31	36	48	89	52	51	91	118	145

	Average On-Peak Trading Prices ($/MWh)[c]								
	2002	2003	2004	2005	2006	2007	2012	2017	2022
January	24	45	50	57	61	65	109	148	186
February	25	63	49	54	54	58	97	126	156
March	36	58	47	57	52	60	102	134	166
April	32	48	49	59	55	71	119	162	205
May	30	49	58	52	53	70	115	155	196
June	33	54	56	55	62	85	148	206	264
July	37	56	58	67	84	75	134	180	227
August	32	53	65	85	63	68	100	126	153
September	35	49	50	93	46	63	91	115	138
October	38	49	52	92	65	68	113	147	182
November	41	42	63	94	69	71	120	157	195
December	46	50	65	96	60	72	105	132	159

[a] Based on data obtained from the Intercontinental Exchange, October 2, 2008.

[b] Off-peak means Monday through Saturday 10 p.m. to 6 a.m. and Sundays and holidays.

[c] On-peak means Monday through Saturday 6 a.m. through 9:59 p.m.

Table 26. Future Locational Electricity Commodity Prices for SGIP Facilities Assuming Perfect Market Competition ($/MWh)

year	Marginal Locational Price (MLP) minimum	average	maximum	MLP Spatial Spread for SGIP-Price Nodes minimum	average	maximum	st dev
2009	0	76	197	0	24	89	9.2
2011	0	66	166	0	22	109	9.3
2013	0	66	250	0	24	155	12
2015	0	73	250	0	27	250	15
2017	0	76	202	0	29	130	15

Figure 6. Hourly SGIP Energy Price Spreads for 2009

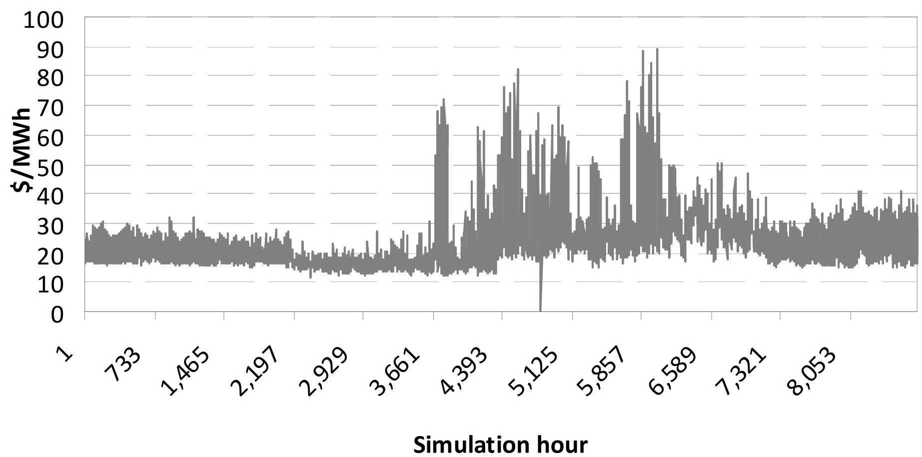

Figure 7. Hourly SGIP Energy Price Spreads for 2011

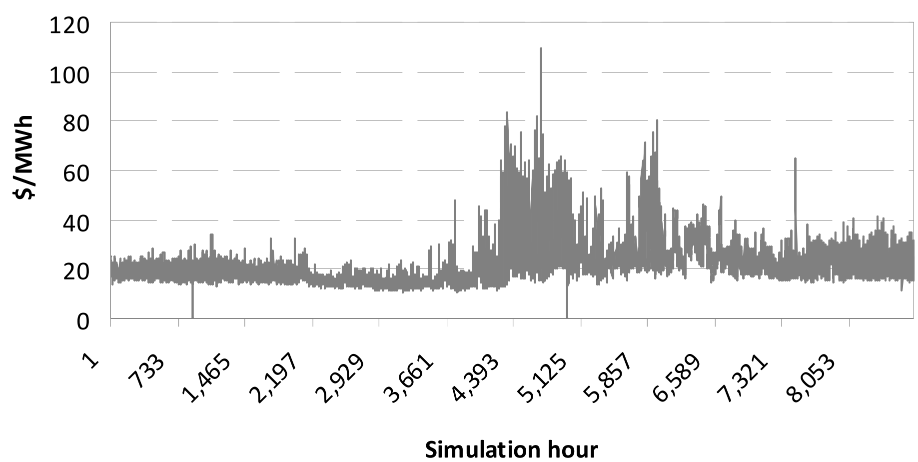

Figure 8. Hourly SGIP Energy Price Spreads for 2013

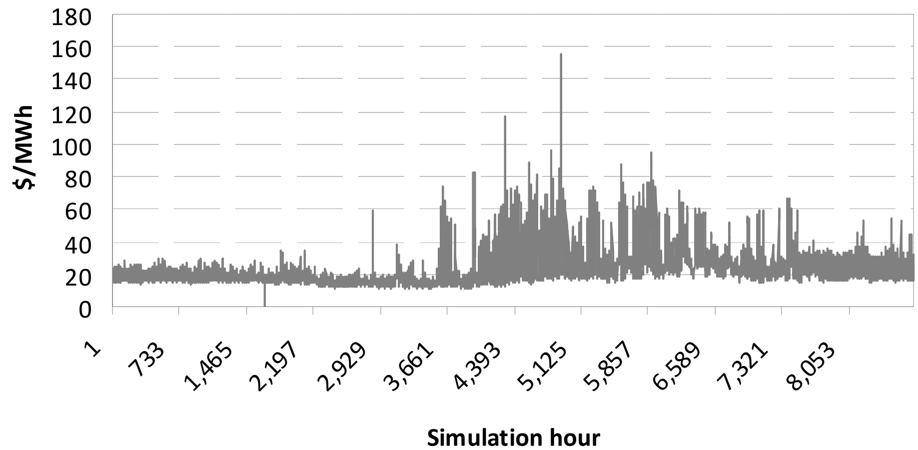

Figure 9. Hourly SGIP Energy Price Spreads for 2015

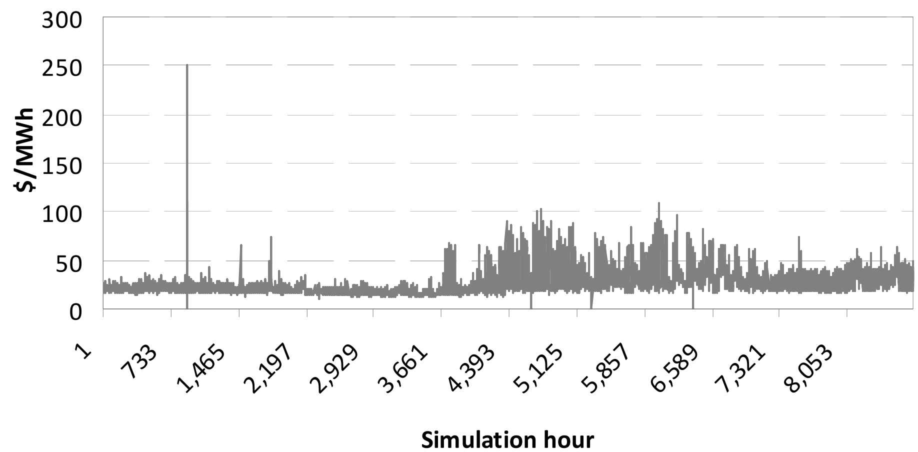

Figure 10. Hourly SGIP Energy Price Spreads for 2017

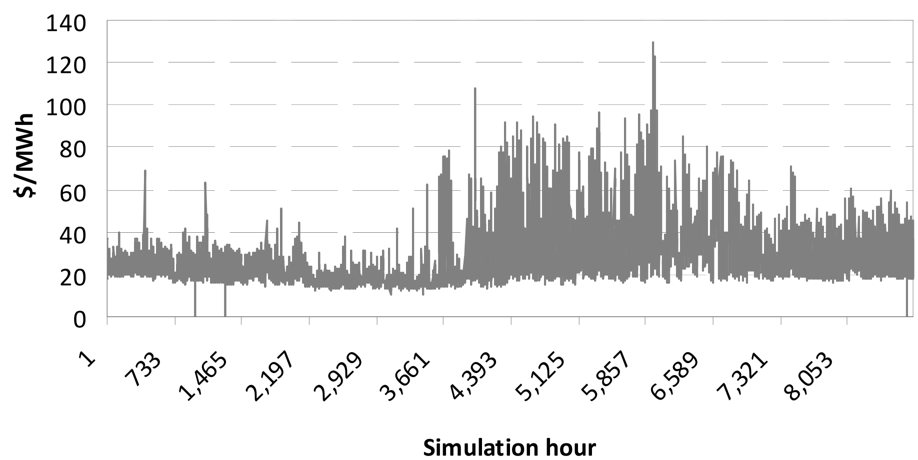

Table 27. Geographic Energy Commodity Price Differentiation for the SGIP

DR	SGIP Price Δ ($/MWh)	SGIP Price Δ Duration (% of Year) 10%	20%	50%	100%
		dollars per watt per year			
	10	0.88	1.75	4.38	8.76
	20	1.75	3.50	8.76	17.52
	50	4.38	8.76	21.90	43.80
	100	8.76	17.52	43.80	87.60
		dollars per watt			
2.8%	10	$0.18	$0.35	$0.88	$1.76
	20	$0.35	$0.70	$1.76	$3.52
	50	$0.88	$1.76	$4.41	$8.81
	100	$1.76	$3.52	$8.81	$17.62
		dollars per watt			
8%	10	$0.10	$0.20	$0.49	$0.99
	20	$0.20	$0.39	$0.99	$1.97
	50	$0.40	$0.99	$2.47	$4.93
	100	$0.99	$1.97	$4.93	$9.86
		dollars per watt			
15%	10	$0.06	$0.12	$0.29	$0.58
	20	$0.12	$0.23	$0.58	$1.15
	50	$0.29	$0.58	$1.44	$2.88
	100	$0.58	$1.15	$2.88	$5.75

Distribution Deferral

Due to time constraints and limited data availability, the results presented in this section should not be taken as the final word on the subject of distribution deferral. Nevertheless, useful findings have been established:

- Self-generation can defer distribution system upgrades as evidenced by the number of applications with positive results; and
- The fact that the promising cases ranged from 13 to 39 percent of the applications with sufficient information indicates the need for a different approach to design and implement incentive programs.

Because distribution engineers have many options for managing heavily loaded circuits and transformers, and since customer generation may not be available when the system needs it, the positive results are presented as potential cases of upgrade deferral savings.

Table 28 lists the cases with insufficient data and/or documentation to determine their ability to defer distribution upgrades and Table 29 shows the statistics for those self-generation applications that were deemed to be definitely incapable of deferring secondary transformer upgrades. In the case of PG&E and SCE, the cases incapable of deferring distribution investments are almost three times as many as the promising ones, whereas in the case of SDGE the cases incapable of deferring distribution investments are twice the promising ones. Again, there is need for a better approach to ensuring higher success ratios.

Tables 30 and 31 summarize the findings of the analysis of generators that have the potential to defer distribution upgrades. Because of time limitations, the results pertain only to assessing secondary transformer upgrading opportunities. The summary shows that the number of promising non-PV cases amounts to 26 percent, 23 percent, and 33 percent of the adequately documented SGIP applications for PG&E, SCE, and SDGE. This finding points to the need for a better approach to achieve higher success ratios.

Sufficient data were available for PG&E and SDGE applicants to estimate the average length of time of the achievable deferral of secondary transformers, as shown in Table 31. The average deferral duration ranges from 2.2 to 14 years for PG&E and 5 to 5.5 years for SDGE. Note that long deferral periods imply SGIP investments on heavily loaded circuits serving slow-growth areas.

It is worth noting that there were delays in the stage of this project when data were gathered. Due to these delays, the results and analyses presented in this section do not fully reflect the analytic value of the proposed methodology to analyze grid impacts of distributed generation; however, the results are compelling. Although these results could be expanded with further research, the grid impacts analysis leads to significant public policy relevant conclusions and recommendations presented in Chapter 5.

Table 28. Cases Lacking Information to Assess Deferring Distribution System Upgrades

		PG&E			SCE			SDGE		
			Nameplate Capacity (kW)			Nameplate Capacity (kW)			Nameplate Capacity (kW)	
		n	Total	Average	n	Total	Average	n	Total	Average
PV		5	816	163	161	25,308	157	43	10,839	252
ICE	-NR	--	--	--	33	17,485	530	7	5,500	786
	-R	--	--	--	1	370	370			
MT	-NR	1	63	63	19	3,071	162	8	666	83
	-R				3	300	100			
FC	-NR							3	2,000	667
	-R				1	250	250			
GT-R					1	100	100	3	9,370	3,123
unknowns [a]		228	86,413	379						
subtotal (non-PV)		1	63	63	58	21,576	372	21	17,536	835
total		234	87,292	373	219	46,884	214	64	28,376	443

[a] Cases for which the records did not specify the generation technology applied.

Table 29. Applications Incapable of Deferring Secondary Transformer Upgrades [a]

		PG&E			SCE			SDGE		
			Nameplate Capacity (kW)			Nameplate Capacity (kW)			Nameplate Capacity (kW)	
		n	Total	Average	n	Total	Average	n	Total	Average
PV		180	20,711	115	24	6,632	276	31	2,890	93
ICE	-NR	28	6,717	240	5	3,475	695	7	2,800	400
	-R				2	920	460			
MT	-NR	18	1,717	95	5	1,530	306	5	660	132
	-R				1	420	420			
FC	-NR									
	-R				2	1,250	625			
GT-R										
subtotal (non-PV)		46	8,434	183	15	7,595	506	12	3,460	288
total		226	29,145	129	39	14,227	365	43	6,350	148

[a] Allowing secondary transformers to be loaded up to 130% of nameplate ratings.

Table 30. Summary Results for Potential Distribution Upgrading Deferrals

Category	PG&E			SCE				SDGE		
	PV	non-PV	all	PV	non-PV -NR	non-PV -R	all	PV	non-PV	all
Positive Cases	76	16	92	20	14	4	38	21	6	27
% of Total Candidate Cases	30%	26%	29%	10%	18%	27%	13%	40%	33%	39%
% of Total # of All Cases	29%	25%	17%	3%	7%	9%	4%	22%	15%	20%
Total kW of Positive Cases	10,463	5,285	15,748	1,680	5,540	2,480	9,700	3,852	1,305	5,157
% of All Candidate Cases kW [a]	34%	39%	35%	5%	18%	36%	14%	57%	27%	45%
% of Total kW of All Cases [a]	33%	38%	12%	1.4%	23%	2%	4%	22%	6%	13%
Candidate Cases	256	62	318	205	77	15	297	52	18	70
Total kW of Candidate Cases [b]	31,174	13,718	44,892	33,620	31,251	6,840	71,711	6,742	4,765	11,507
Total Number of Records [b]	261	63	552 [c]	664	189	44	897	95	39	134
Total Number of kW in Records	31,990	13,782	132,185 [c]	118,055	23,761	111,981	253,797	17,581	22,301	39,882

[a] Candidates have sufficient and consistent information to enable further evaluation.

[b] Totals include candidates plus rejections for lack of information, suspect data, and duplicate records

[c] Values include records lacking generation technology specification

Table 31. Applications with Potential Deferrals of Secondary Transformer Upgrades

		PG&E				SCE			SDGE			
			Nameplate Capacity (kW)		Average Deferral		Nameplate Capacity (kW)			Nameplate Capacity (kW)		Average Deferral
		n	Total	Avg	(Years)	n	Total	Average	n	Total	Average	(Years)
PV		76	10,463	138	10	20	1,680	84	21	3,852	183	5.5
ICE	-NR	9	4,055	451	14	12	5,180	432	3	925	308	5.3
	-R					3	1,730	577				
MT	-NR	6	630	105	2.2	1	60	60	3	380	127	5.0
	-R					1	750	750				
FC	-NR	1	600	600	3.0	1	300	300				
	-R					0	0	0				
GT-R						0	0	0				
subtotal (non-PV)		16	5,285	330	9.1	18	8,020	446	6	1,305	218	5.2
All Technologies		92	15,748	171	10	38	9,700	255	27	5,157	191	5.4

* Allowing secondary transformers to be loaded above their nameplate ratings.

Summary of Results: Costs and Benefits

To the extent possible, the following section considers the three (3) perspectives listed earlier and the cost and benefit elements detailed in Table 2.

Participant Test

Electricity Bill Savings

SGIP participants realize significant benefits from reduced electricity and, where appropriate, natural gas bill savings. Additional charges on the participant's bill come from increased natural gas purchases to operate non-renewable DG technologies.

The participant bill savings is calculated from electricity offset by the DG application at each hour and the corresponding electricity rate for each utility. For renewable and non-renewable fueled technologies (ICE, MT, FC and GT), additional electricity and natural gas offsets were calculated from the useful recovery of energy through the combined heat and power technology. From the Sixth Year Impact Evaluation Report from Itron (Itron August 2007), the breakdown of end-use applications of combined heat and power is distinguished between heating and cooling. The heating offsets natural gas use which would have been used in a boiler to create useful heat. The cooling offsets additional electricity that would have been used in an electric chiller.

The benefits of the electricity and natural gas saving reductions (and costs) have been determined using the time of use rate structures from each IOU: E19 for PG&E, TOU-8 for SCE, and AL-TOU for SDGE. The savings (in millions of dollars, 2006) shown in Table 32 are divided into three categories: savings on the electricity bill ("e-"), displaced electricity use in combined heat and power applications using a chiller ("chiller"), and displaced natural gas savings for combined heat and power applications using a boiler ("boiler").

Table 32. Electricity and Natural Gas Savings (in millions $2006)

	PG&E			SCE			SCG			SDGE			
	e-	chiller	boiler	e-	chiller	boiler	e-	chiller	boiler	e-	chiller	boiler	total
PV	152.1	--	--	52.0	--	--	30.1	--	--	37.6	--	--	271.8
ICE-NR	304.5	5.5	58.8	123.7	2.2	25.1	235.8	4.2	47.2	56.0	1.0	11.3	875.3
ICE-R	23.6	0.4	--	11.7	0.2	--	6.4	0.1	--	--	--	--	42.5
MT-NR	44.3	1.6	20.7	21.5	0.8	10.4	29.5	1.1	13.9	7.2	0.3	3.2	154.4
MT-R	9.8	0.4	--	6.8	0.2	--	--	--	--	3.7	0.1	--	21.0
FC-NR	33.0	0.5	5.9	5.8	0.1	1.1	12.3	0.2	2.4	12.9	0.2	2.5	76.8
FC-R	--	--	--	2.1	--	--	--	--	--	--	--	--	2.1
GT	50.4	1.0	10.6	--	--	--	49.8	1.0	11.2	50.6	1.0	11.9	187.6
WD	--	--	--	3.9	--	--	--	--	--	--	--	--	3.9
sub-total	617.7	9.3	96.0	227.5	3.5	36.6	363.8	6.6	74.7	168.0	2.6	29.0	
total	723.0			267.6			445.1			199.6			1,635.3

Operations and Maintenance

The costs of the natural gas use in combined heat and power and non-combined heat and power applications are shown in Table 33.

Table 33. Natural Gas Costs for DG installations (in millions $2006)

technology	PG&E	SCE	SCG	SDGE	subtotal
ICE-NR	377.0	161.1	302.8	72.5	913.4
MT-NR	76.5	38.3	51.2	12.0	177.9
FC-NR	28.2	5.2	11.3	11.9	56.7
GT	63.2	--	66.9	71.2	201.3
total	544.9	204.6	432.2	167.5	**1,349.3**

Note: In the event that a column does not sum to 100 percent, it is a function of rounding and not a calculation error

Operations and maintenance costs (apart from fuel use) were estimated as part of the Macroeconomic Impacts, discussed in Chapter 2. The refined estimates of operations and maintenance (excluding the cost of natural gas, see Table 33) are shown here in Table 34.

Table 34. O&M Costs of SGIP Installations (in millions $2006)

technology	PG&E	SCE	SCG	SDGE	subtotals
PV	48.12	20.14	11.46	12.58	92.29
ICE-NR	32.13	14.77	26.15	6.12	79.17
ICE-R	2.69	1.19	0.61	0.00	4.49
MT-NR	9.60	5.08	6.81	1.51	23.00
MT-R	2.08	1.49	0.00	0.81	4.37
FC-NR	8.66	1.71	3.66	3.66	17.69
FC-R	0.00	0.61	0.00	0.00	0.61
GT	5.19	0.00	3.57	3.59	12.35
WD	0.00	0.42	0.00	0.00	0.42
total	108.46	45.41	52.26	28.27	234.40

Table 35. Participant Test of the SGIP (in millions $2006)

	costs			benefits		
	capital	O&M	fuel	e- bill savings	SGIP incentives	balance [a]
PV	823.9	92.3	--	271.8	356.1	288.3
ICE-NR	288.6	79.2	913.4	875.3	73.2	332.7
ICE-R	19.2	4.5	--	42.5	6.2	-25.0
MT-NR	51.9	23.0	177.9	154.4	37.7	60.8
MT-R	10.9	4.4	--	21.0	3.4	-9.2
FC-NR	48.8	17.7	56.7	76.8	15.7	30.6
FC-R	7.5	0.6	--	2.1	3.5	2.5
GT	31.6	12.4	201.3	187.6	3.9	53.8
WD	2.3	0.4	--	3.9	1.0	-2.2
sub-total	1284.7	234.4	1349.3	1635.3	500.7	
total		2868.4		2136.0		732.4

[a] Positive numbers indicate a net cost, where as a negative number indicates a net benefit

Note: In the event that a column does not sum to 100 percent, it is a function of rounding and not a calculation error

On balance, the costs and benefits considered here indicate a net cost for SGIP participants; however, some technologies indicate a net benefit for SGIP participants based on the elements considered here. The combustion and turbine technologies operating on a clean or renewable fuel, ICE-R, MT-R, and WD technologies all yield a net benefit for the participant.

Note that there are several high value benefits that have not been considered. In the case of PV, for instance, neither federal tax incentives nor depreciation benefits are considered. TIAX estimates the federal tax incentive credits (FTIC) for PV systems would amount to approximately $56 million (in 2006 dollars).[26] Including this as a benefit in the calculation above still yields a net cost to the SGIP and PV systems; however, it reduces the net cost of PV technologies by nearly 20 percent and the net cost of the entire program to participants by about 8 percent.

Perhaps the most significant benefit not included in the calculation here is the reliability value of on-site generation. Program participants stand to benefit significantly from being able to meet part of or all of their electricity needs with self generation during utility service outages.

Non-Participant and Societal Tests

Due to scheduling constraints, only the elements of the non-participant and societal tests are listed here. In other words, the elements are not aggregated as in the case of the participant test. There is sufficient detail in this report, however, for the reader to make basic assumptions and conduct a non-participant and/or societal test for the

[26] Assuming that the FTIC is 10 percent of the installed costs and paid on the first 200 kW of the installations.

program. The lack of a non-participant and societal test does not impact the recommendations nor conclusions in Chapter 5.

The following cost and benefit elements for the non-participant and societal tests are addressed elsewhere in this report:

costs	**benefits**
O&M Costs (including NG use)	fuel-for-heat savings
DG Equipment Capital Costs	economic impacts
	avoided energy costs

Program Administration Expenditures

The SGIP is administered by the IOUs and the CCSE. There are administration expenses incurred and tracked by the Program Administrators as well as the costs of metering and evaluation (M&E) performed by third parties (e.g., Itron). The expenditures for each PA/IOU for the years 2001-2006 are listed in Table 36, with costs distinguished as administrative ("admin") or metering and evaluation ("m/e").

Table 36. PA Expenditures for the SGIP (in millions $2006)

	PG&E		**SCE**		**SCG**		**SDGE**	
	admin	m/e	admin	m/e	admin	m/e	admin	m/e
2001	0.31	0.00	0.28	0.00	0.61	0.00	0.25	0.00
2002	1.33	0.25	1.09	0.12	0.40	0.07	0.52	0.00
2003	1.46	0.34	0.57	0.38	0.64	0.09	0.53	0.09
2004	1.26	0.79	0.65	0.36	0.45	0.27	0.43	0.23
2005	1.41	1.15	1.99	0.39	0.38	0.43	0.45	0.18
2006	1.78	0.52	1.12	0.22	0.59	0.11	0.60	0.20
sub-totals	7.54	3.05	5.70	1.48	3.07	0.97	2.78	0.70
totals	**10.59**		**7.17**		**4.04**		**3.48**	

Note: In the event that a column does not sum to 100 percent, it is a function of rounding and not a calculation error

Monetized Emission Impacts

The emission impacts detailed previously in Chapter 3 were monetized using the damage costs discussed previously in Chapter 2 and are shown in Table 37.

Table 37. Monetized Emission Impacts of the SGIP (in millions of $2006)

	PG&E				SCE				SCG				SDG&E				Total			
	VOC	NOx	PM	GHG	VOC	NOx	PM	GHG	VOC	NOx	PM	GHG	VOC	NOx	PM	GHG	VOC	NOx	PM	GHG
PV	-0.02	-0.17	-6.77	-9.39	-0.01	-0.06	-2.42	-3.35	-- [a]	-0.04	-1.42	-1.96	-- [a]	-0.05	-1.84	-2.55	-0.03	-0.32	-12.45	-17.25
ICE-NR	20.22	24.43	-31.23	5.95	9.08	11.02	-14.12	2.70	17.30	20.86	-26.06	4.75	3.95	4.74	-5.88	1.06	50.55	61.06	-77.30	14.46
ICE-R	-0.02	-0.23	0.23	-2.14	-0.01	-0.12	0.12	-1.13	-- [a]	-0.06	0.06	-0.55	--	--	--	--	-0.03	-0.41	0.41	-3.82
MT-NR	0.06	0.28	-2.93	1.58	0.04	0.18	-1.34	0.84	0.04	0.07	-3.00	0.92	0.01	0.09	-0.18	0.35	0.15	0.63	-7.45	3.69
MT-R	-0.01	-0.19	-1.67	-1.00	-0.01	-0.14	-1.26	-0.67	--	--	--	--	-0.01	-0.08	-0.71	-0.41	-0.03	-0.41	-3.64	-2.07
FC-NR	-0.02	-0.28	-3.20	-0.56	--	-0.04	-0.50	-0.08	-0.01	-0.11	-1.30	-0.23	-0.01	-0.11	-1.34	-0.24	-0.04	-0.54	-6.34	-1.10
FC-R	--	--	--	--	--	-0.02	-0.25	-0.19	--	--	--	--	--	--	--	--	--	-0.02	-0.25	-0.19
GT	0.03	4.10	-1.50	0.69	--	--	--	--	0.03	4.53	-1.70	0.76	0.03	4.41	-1.63	0.74	0.08	13.04	-4.83	2.18
WD	--	--	--	--	--	-0.01	-0.20	-0.28	--	--	--	--	--	--	--	--	--	-0.01	-0.20	-0.28
Total	20.24	27.93	-47.07	-4.86	9.09	10.82	-19.97	-2.16	17.35	25.26	-33.42	3.69	3.97	9.00	-11.59	-1.05	50.65	73.01	-112.04	-4.38
																		Balance	+7.2	

Note: A positive value indicates a net cost and a negative value indicates a net benefit.

[a] In these cases, the reductions are too small to report and are effectively considered zero.

Distribution Deferral

The potential deferral savings of the SGIP are listed in Table 38 on a dollar per kW basis. There are multiple scenarios for transformer costs presented, based on varying discount rates (“DR”) and transformer cost escalation percentages (“TCE”). Estimates of potential deferral savings were developed using transformer equipment costs supplied by PG&E. The results indicate a wide range of benefits from $0.09/kW (for a transformer costing 5 percent below average, a 2 percent discount rate and annual escalation of 1 percent, and the lowest deferral-value application) to $340/kW (representing transformer cost 150 percent above average, a 15 percent discount rate, 6 percent escalation, and the highest deferral-value application). This information points out potential offsetting of SGIP costs for non-participants and society as a whole.

Table 38. Potential Deferral Savings (in $/kW)

DR / TCE Scenarios [a]	Variation over All SGIP Cases [b]	Transformer Cost Scenario		
		low	medium	high
2% / 1%	minimum	0.09	0.17	0.26
	average	3.5	7.0	10
	maximum	31	62	93
8.5% / 3.5%	minimum	0.41	0.82	1.2
	average	12.8	26	39
	maximum	93	186	280
15% / 6%	minimum	0.70	1.4	2.1
	average	18	37	55
	maximum	113	226	340

[a] DR – discount rate; TCE – transformer cost escalation

[b] Except for those for which sufficient information was not available.

Although the results presented here were insufficient to perform the non-participant and societal tests, this only limits the recommendations related to the quantitative level of incentives. However, the impact results are sufficient to shape conclusions and recommendations for the SGIP moving forward, as detailed further in Chapter 5.

CHAPTER 4: The SGIP Moving Forward

Effective January 1, 2008, the eligible technologies for incentive funding under the SGIP are limited to fuel cells and wind distributed generation technologies. However, it is possible that other emerging technologies will be included before the program's currently scheduled end date of January 1, 2012. The SGIP Handbook specifically provides for adding new technologies to the program, and has established guidelines for doing so. In a study of DG technologies performed by Arthur D. Little for EPRI in 1999, the list of technologies included microturbines (MTs), small gas turbines (GTs), reciprocating internal combustion engines (ICEs), Stirling engines, several fuel cell technologies, and energy storage. The DG update performed by TIAX for EPRI in 2005 confirmed this list as the only foreseeable candidate technologies (TIAX January 2006). Because MTs, GTs, and ICEs were formerly SGIP eligible, and fuel cell technologies remain eligible, the Stirling engine and energy storage are considered here. These are discussed in the following subsections. A discussion of renewable fuels for use in combustion technologies and combined heat and power are also included as it is possible that engine and turbine technologies operating exclusively on renewable fuels and including the use of combined heat and power could see renewed interest and restored eligibility.

Stirling Engines (Renewable Fuels)

Stirling engines are attractive due to the benefits derived from external combustion, resulting in clean combustion products and multi-fuel or fuel-switching capabilities. Unlike internal combustion engines, the working fluid which produces power in the moving cylinders is a separate inert gas. The burner and the combustion exhaust gases are kept completely outside of the inner workings of the machine. Thus the combustion can be much cleaner and occurs at lower temperature, thereby lowering NO_x emissions. The Stirling engine can accept a wide range of fuels, many of which are normally problematic in other engine applications, such as sawdust and biomass-derived fuels. Stirling engines are also characterized by high-efficiencies and low maintenance. To date, most available Stirling engines have capacities in the 1-25 kW range, and commercially competitive increased power capabilities are unlikely (TIAX January 2006). Thus, to establish an installation with some significant generating capacity, multiple Stirling engine generators would be needed. These multi-generator systems are largely unproven and likely quite costly.

Energy Storage

As discussed previously in Chapter 3, the temporal and spatial components of electric power capacity can have disproportionate value in certain locations if available during peak time periods. Given this, energy storage capacity is an excellent candidate for the SGIP. Recently, a Program Modification Request was submitted for advanced energy storage systems, reviewed, and endorsed by the SGIP Working Group. The CPUC is currently considering the request and is expected to render a decision in the near future.[27] Studies have been performed on hybrid PV-battery storage (TIAX March 2007) and FC-battery storage systems (Zogg August 2000), however, energy storage systems can be coupled with any generation technology. In addition to a wide range of current and future battery technologies, there are a variety of energy storage technologies, such as flywheel, compressed-air energy storage, super-conducting magnetic energy storage, pumped hydro, super capacitors, and hydrogen generation and storage. However these alternate storage technologies are generally not appropriate for consideration as DG technologies. Pumped hydro and compressed-air energy storage are utility scale storage technologies having usual capacities in the several tens to several hundreds of MW range. Flywheel, super-conducting magnetic energy storage, and super capacitors are also utility technologies in that they have stored energy depletion times of the order of seconds to minutes. Thus, these technologies find use in utility voltage and frequency regulation applications. Hydrogen generation and storage, in which hydrogen generated by hydrolysis is stored for later use to produce power via fuel cell, could be applied in DG applications. But, the inefficiencies of the processes involved (hydrolysis in particular) make such systems poor choices compared to battery storage approaches.

Lead acid battery technology is well developed; however, the lifetime of the batteries can be limited in the deep discharge cycling operation associated with DG applications. To overcome these limitations, advanced battery technology developments driven by the portable electronics and electric vehicle applications are improving performance and lowering costs of emerging battery technologies. In fact, one specific use for expended electric or plug in hybrid electric vehicle batteries is as energy storage capacity in DG applications.

EPRI has documented a number of advanced battery technology demonstrations in DG applications (TIAX January 2006; Rastler July 2008) that could find ready use in DG applications as part of the SGIP:

- 1 MW NaS battery at a New York Power Authority site
- 1 MW NaS battery at an American Electric Power substation
- 1 MW Altair Nano Li-ion battery at an American Electric Power site
- 2 MW Premium Power ZnBr battery at a PG&E site

Clean Alternative and Renewable Fuels for Use in Combustion Technologies

As noted above, the changes in the SGIP, effective January 1, 2008, limit incentives to fuel cells and wind turbine technologies. Thus, even renewable fuels can only be used

[27] Sempra Energy Comments – 2008 IEPR – SGIP Cost-Benefit Analysis, comment to Docket 08-IEP-1G, Self Generation Incentive Program Cost Benefit Analysis, September 5, 2008,. http://www.energy.ca.gov/2008_energypolicy/documents/2008-09-03_workshop/comments/Sempre_Energy_Utilities_comments_on_Self_Generation_Incentive_Program_TN-47932.pdf

in conjunction with a fuel cell technology to be SGIP eligible. It is possible, however, that the formerly eligible engine and turbine technologies such as microturbines may regain SGIP eligibility if they operate on renewable fuels. These renewable fuels include landfill gas, or digester gas from dairy waste or waste water treatment processes. In addition, renewable feedstocks that can be available in significant quantities to use for biomass-derived fuels include vegetable oils (e.g., soybean, palm, and canola oils, and used cooking oil often referred to as yellow grease), waste animal fats, and biomass waste streams (e.g., lawn clippings), food (restaurant) waste, agricultural waste (e.g., seeds, pits, and husks), forest residue, commercial food industry waste, construction debris, and municipal solid waste. Vegetable oils and animal fats can be converted to renewable biodiesel via a trans-esterification process. The other biomass wastes noted can be converted into a renewable biodiesel via some combination of: pyrolysis to produce fuel oils and gas; gasification to produce synthetic fuel gas (producer gas or syngas); or conversion of syngas to diesel via Fischer-Tropsch synthesis.

These renewable fuels can be used in formerly SGIP eligible engine and combustion turbine technologies. For example, Capstone is currently working on powering MTs with hydrogen and syngas. DG projects using renewable fuels could be granted incentive funding on a case by case basis, or after potential reinstatement of these technologies to the program.

Combined Heat and Power

Combined heat and power is an enhancement of traditional DG technologies, such as microturbines, turbines, fuel cells and internal combustion engines that combines electricity production and thermal energy recovery for additional efficiency and energy offsets for on-site energy needs. The thermal energy can be used to produce steam, hot water, hot air or chilled water for a work environment or process cooling. This use of the thermal energy is an additional imported energy offset to the electricity produced by the DG system and increases the overall energy efficiency of the system. In the future, combustion energy technologies (including fuel cells) will likely be incorporated into combined heat and power systems for increased system efficiency and maximum electricity grid benefits.

CHAPTER 5: Conclusions and Recommendations

This section: 1) considers the impacts evaluated as part of the analysis, categorized broadly as environmental, macroeconomic, and grid impacts, 2) explores the application of the cost-benefit methodology employed here and how it can be improved, and 3) makes recommendations related to the SGIP moving forward.

Environmental Impacts

The environmental benefits of the SGIP, although small, indicate that systems operating with clean and renewable fuels, particularly those in efficient combined heat and power applications, do provide air quality benefits and GHG reductions. The benefits of these applications to date are small, however, this is primarily a reflection of the installed capacity of clean and renewable sources of DG. It is important to note that the IOUs are required to meet the RPS moving forward and that marginal power generation is getting increasingly cleaner. In other words, even if one argues that the environmental benefits are too low in this report because the analysis did not include 'peaker' plants or other less efficient generation resources, the impact of the 'peaker' plants on the generation resource mix is likely to decline significantly as more renewable generation resources come online over the next decade and longer. It will be a challenge for DG applications, at the current state of technology, to decrease GHG emissions significantly without a drastic increase (i.e., two orders of magnitude or more) of installed capacity.

Macroeconomic Impacts

The analysis presented here indicates that the SGIP has added significant value to the California economy, in terms of value added, total output, and employment (as full-time equivalents, FTE). It is noted that the model also predicts that total output of the program and compensation per FTE is slightly higher than if the incentives were dedicated to household expenditures (or personal consumption expenditures); however, the value added and the total employment (as FTE) is higher in the case of household expenditures.

To improve estimates of the macro-economic impacts of the SGIP further, it would be worthwhile to collect data on power plants that California utilities have constructed in the recent past. These data would include the locations of the firms that constructed the power plants, the dollar amounts of the contracts and the place or residence of the workers that were employed. This information would be useful to compare to similar data for DG facilities.

Grid Impacts

Although further research and analysis is warranted, the grid impacts analysis to date confirms that there are location dependent benefits of SGIP installations and that the benefits are not uniform across the IOU service zones. Most of the benefits will accrue from energy commodity-related savings with the inauguration of the CAISO market structure and rules to be enacted n 2009. The prevalence of spatial price dispersion indicates that there is significant opportunity to improve the cost effectiveness of self-generation investments (and other forms of DERs). It is also important to note that the unique 9-step methodology employed in this report will likely yield higher return on investments than the current methodology accepted by the CPUC, which assesses DG investments based on climate-zones. Furthermore, the analysis here indicates an opportunity to explore other methodologies in the determination of grid impacts to ensure maximum return on DG investments.

Cost-Benefit Methodology

This report includes significant advances in the development of a cost-benefit methodology that can be applied to DG programs, and other demand side management programs. The TIAX team recognizes that there are costs and benefits that have not been included in this analysis and these are indicated throughout the report where appropriate. However, this report is intended to contribute to the ongoing debate related to the costs and benefits of DG, rather than settle it.

The environmental impacts were determined using a NG CCCT power plant as a baseline for emissions. Although a relatively clean and efficient baseline, it is appropriate if DG applications are to contribute meaningfully to California's GHG reduction goals and/or the RPS requirements. Furthermore, air quality pollutants have been accounted for on a California-specific basis, accounting for appropriate upstream emissions, and GHG emissions have been accounted for on a lifecycle basis.

The macroeconomic impacts were determined using a standard approach with the IMPLAN model. There is additional work that needs to be done in terms of identifying the net macroeconomic impacts of the SGIP as compared to the gross macroeconomic impacts. The benefits reported here, however, provide a quantitative upper bound for the indirect economic impacts of the SGIP. Moving forward, a similar approach employed here by JFA should be used to quantify the macroeconomic impacts of installing a NG CCCT power plant, for instance.

The framework developed for this report to investigate the grid impacts of DG installations as part of the SGIP is comprehensive and robust in that: a) it incorporates anticipated market redesigns; b) it is seamless in that it applies to all demand/supply technologies and alternatives including DG, energy efficiency, QFs and bulk-power markets with a unified and consistent approach; and c) it bridges the small (at the distribution circuit) with the large (at the large power station bus).

Although this report did not aggregate the monetized cost and benefit elements to perform the non-participant and societal tests, it is highly unlikely that the benefits of the SGIP will outweigh the costs from either of these perspectives. The participant test, which is likely the most favorable perspective in terms of benefits outstripping costs, yielded a net cost for the SGIP,[28] which does not bode well for the other two tests. At this stage of the analysis, there is little evidence to suggest that the SGIP's benefits would outweigh its costs in either the non-participant or societal test. This is not to say that these tests are not useful; however, it is important to emphasize qualitatively that it

[28] Note that there are some high value benefits not included in this analysis, namely the value of local reliability.

is highly unlikely that the current structure of the SGIP will yield benefits that outweigh the costs.

Recommendations for the SGIP

TIAX recommends that the objectives of the SGIP be revisited. TIAX considers this an essential step to eliminate what seems to be an ad hoc approach towards the SGIP and align the program with the Energy Commissions stated goals of increased DG resources in California.[29] The original objectives of the program were to provide “incentives for distributed generation to be paid for enhancing reliability” and “differential incentives for renewable or super clean distributed generation resources (CPUC March 29, 2001)” Furthermore, the CPUC also stated that the incentives provided are intended to:

- encourage the deployment of distributed generation in California to reduce the peak electric demand,
- give preference to new renewable energy capacity; and
- ensure deployment of clean self-generation technologies having low and zero operational emissions.

A clarification of the SGIP objectives and goals as a program funded by ratepayers will go a long way towards justifying eligibility and incentive levels. The power generation industry is operating in a considerably different market reality today as compared to March 2001 when the SGIP was originally enacted.

As it is currently structured, the SGIP is unlikely to play a major role in a statewide GHG reduction effort. TIAX’s reading of SGIP-related documentation from both the CPUC and the Energy Commission suggests that the program objectives are currently tilted toward peak demand reduction and improvements to the grid, without backsliding on air quality pollutants and GHG emissions (as compared to central power generation). This is a reflection of the fact that the program was established and initiated during a time of significant volatility in California’s electricity sector. The baseline for emissions from central power generation used in this report is clean and efficient. Even with this clean baseline, it is clear that internal combustion engines (ICEs), microturbines (MTs), and gas turbines (GT) operating with a renewable fuel in combined heat and power applications reduce criteria pollutant and GHG emissions. Similarly, fuel cells (operating with both renewable and clean nonrenewable fuels) and wind turbines reduce criteria pollutant and GHG emissions. In order for the SGIP to continue its objectives of enhancing the grid and providing environmental benefits, TIAX recommends the restoration of the SGIP eligibility of ICEs, MTs, and GTs operating with a clean or renewable fuel in a combined heat and power application and the continued eligibility of FCs and WD applications.

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[29] Per the Executive Summary of the 2007 Integrated Energy Policy Report (IEPR): “Since 2003, California’s energy policy has defined a **loading order** of resource additions to meet the state’s growing electricity needs: first, energy efficiency and demand response; second, renewable energy and distributed generation; and, third, clean fossil-fueled sources and infrastructure improvements.”

TIAX also recommends that an installed capacity goal be developed based on the market potential for DG applications operating with a clean or renewable fuel in combined heat and power applications. Note that the goals for installed capacity should be established without preference for any of the technologies listed here. Furthermore, it seems that wind turbines as DG installations have not garnered sufficient interest under the SGIP. The Energy Commission, CPUC, and IOUs should consider a strategy to target customers (and areas) that could benefit from wind installations under the SGIP.

With regard to the grid, there are potentially significant benefits to be expected from past SGIP investments with most of it from energy commodity-related savings as of 2009. There are incidental examples of fairly sizable distribution investment deferral savings. The SGIP can be made more cost effective for non-participants by locationally differentiating the incentives in ways much more effective than the climate-zones approach currently used. This report advocates against an approach to configure incentives (or part of incentives) by using area-wide deferral avoided cost values. This approach may produce inefficient and inequitable DG investments. Granting deferral credits to anyone who wishes to participate may lead to further inefficient allocation of incentive funds since planning areas are bound to have circuits that require no upgrades and circuits where load growth is too fast to allow any opportunity for deferring needed investments. Similarly, the economic worth of the deferral opportunities varies widely among customers. Customers capable of participating in a self-generation program but do not offer comparable distribution upgrading deferral savings would be rewarded inequitably under area-wide postage stamp approaches. The new investment strategy would have to be worked out with the IOUs since it will require revamping the role of their distribution planning departments.

TIAX notes that the recommendation to differentiate incentives based on both technology *and* location contradicts the original decision of the CPUC which states that "the incentive payment for this program should be uniform statewide, as the market for self-generation technologies is not limited to or differentiated by a particular region or utility territory (CPUC March 29, 2001)." TIAX concurs with the CPUC regarding the market for DG technologies being uniform across the state; however, the program is also intended to "provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just individual customers." The analysis here demonstrates that the benefits of DG to the electricity system as a whole are not evenly distributed. As such, the SGIP incentives paid by the ratepayer (i.e., non-participant) may not be an accurate reflection of the value to the electricity system as a whole.

Note that the recommendation to differentiate incentives based on real grid benefits does not contradict the CPUC's hesitance to afford "program administrator's flexibility to design the self-generation incentive levels for their individual programs." The CPUC opted against this approach because it "may confuse consumers, or cause them to wait for the possibility of higher incentives before installing self-generation systems." This report is not suggesting that Program Administrators be given flexibility to design the incentives. However, there should be some level of engagement with the distribution level planning departments at the IOUs to maximize the ratepayer funded incentives and ensure that subsidized costs "reflect the value to the electricity system as a whole, and not just individual consumers."

Ultimately, the SGIP must balance (at least) two goals: 1) an expanded DG market and 2) benefits to society. The incentives should be structured to subsidize the costs of technologies to meet the first goal. To meet the second goal, however, the incentives should differentiate between the cleanest technologies. Finally, there should be some added incentive for installations that offer location-specific benefits.

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LIST OF ACRONYMS

CAISO	California Independent System Operator
CARB	California Air Resources Board
CCSE	California Center for Sustainable Energy
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DG	Distributed Generation
EPA	Environmental Protection Agency
E3	Energy and Environmental Economics, Inc.
FTIC	Federal Tax Incentive Credit
FTE	Full Time (Worker) Equivalents
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IMPLAN	Impact Analysis for Planning
I-O model	Input-Output model
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
JFA	Jack Faucett Associates - subcontractor to TIAX
LMP	Locational Marginal Price
MAPS™	Multi Area Production Software (from GE)
MCP	Market Clearing Price
MRTU	Market Re-design and Technology Update
NAICS	North American Industry Classification System
NG CCCT	Natural Gas fired Combined Cycle Combustion Turbine
NHTSA	National Highway Traffic Safety Administration
NIMBY	Not In My BackYard
NO_x	Nitrogen Oxides
O&M	Operations and Maintenance
PA	Program Administrator
PG&E	Pacific Gas & Electric
PM	Particulate Matter
PPI	Producer Price Index
QF	Qualifying Facility
RA	Resource Adequacy
RPC	Regional Purchasing Coefficient
RPS	Renewable Portfolio Standard
SCC	Social Cost of Carbon
SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SGIP	Self Generation Incentive Program

SCG	Southern California Gas
SCF	Sectional Center Facility
SPM	Standard Practice Manual
T&D	Transmission and Distribution
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council

Distributed Generation Technologies

PV	photovoltaic
ICE	internal combustion engine
MT	microturbine
FC	fuel cell
GT	small gas turbine
WD	wind turbine
-NR	a combustion technology using a non-renewable fuel
-R	a combustion technology using a renewable fuel

Units of Measurement

g	grams
kBtu	kilo British thermal units
kVA	Kilovolt-Ampere
kW	Kilowatt ($1x10^3$ Watts)
kWh	Kilowatt hours ($1x10^3$ Watt hours)
MJ	Megajoule
MMT	Million Metric Tons ($1x10^6$ metric tons)
MW	Megawatt ($1x10^6$ Watts)
MWh	Megawatt hours ($1x10^6$ Watt hours)

Compounds

CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
N_2O	nitrous oxide
NO_x	nitrogen oxides
PM2.5	particulate matter (smaller than 2.5 microns)
VOC	volatile organic compounds