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Attachment A
Supporting Material for SGIP Workshop
TIAX LLC
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Overview of Cost-Benefit Analysis

1. Scope

The scope of our work is defined as a cost-benefit analysis (CBA) of the Self-Generation Incentive Program (SGIP) based on program activity through the year 2006. Our analysis is not bounded by the Standard Practice Manual (SPM) developed by the California Energy Commission (CEC) and the CPUC, which was designed to provide 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). Our CBA, however, is consistent with the core elements of the SPM framework and its respective tests and is easily adaptable to perform analyses in line with the SPM.

Traditionally, CBAs are conducted prior to initiating public programs to determine the economic value of the program and its alternatives. In principle, a CBA will determine if a program qualifies on cost-benefit grounds based on the present value of benefits compared to the present value of costs. In other words, the CBA serves as an appraisal technique for public investments and public policy. In the case of SGIP, however, the program is actively paying incentives for self-generation installations and has been doing so since it started in March of 2001. As such, our CBA is slightly different than the traditional analysis in that we are determining the costs and benefits of the program based on installed generators that received SGIP incentive funding between 2001 and 2006. Our goal then is to quantify the benefits and costs of the program through 2006, rather than determine whether a program qualifies on a cost-benefit grounds (i.e., benefits > costs). That said, our analysis will provide the foundation to perform a forward-looking CBA that will help shape SGIP in the future to ensure that the program provides net benefits.

1.1 The Elements of CBA

With our scope defined, we turn to the design of our CBA, characterized by various elements. The characteristics of the CBA are defined by a series of logical steps. We've already considered the first step in our scope: Identifying the policy or project to be evaluated. Secondly, we determine standing i.e., whose costs and benefits are counted. This is the same question of perspective that is discussed elsewhere.[1,2] In the case of SGIP, there are a number of groups with standing: the participant who installs a generator, the non-participant (i.e., the ratepayer without SG), and society. Because we are evaluating SGIP as a public investment, we define standing in a general way that includes costs and benefits to *society*.

[1] California Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects, CPUC, October 2001.
[2] Framework for Assessing the Cost-Effectiveness of the Self-Generation Incentive Program, Itron Inc., CPUC, March 2005.

Having identified the program and determined standing, we turn to the benefits and costs. There are two steps related to the benefits and costs. Firstly, we need to identify the benefits and costs to be considered. We need to ensure that the major elements in both categories are included and that double counting is avoided. Itron's previous report to the CPUC[3] includes a comprehensive list and description of the costs and benefits of SGIP (and more generally, distributed generation, DG). The costs and benefits of SGIP are listed in Table 1.

Secondly, we need to determine and outline our approach to value the benefits and costs. 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. On the other hand, some benefit elements of the incentive program are much more difficult to value (i.e., monetize). For instance, the environmental benefits of SG 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 is trivial to determine. Our methodology for determining the benefits and costs of the program is discussed in greater detail in Sections 3.4 and 3.5.

Table 1. Cost and Benefit elements of SGIP

Benefits	Costs
Environmental Benefits	Installed Equipment Costs
Macroeconomic Benefits	Operations and Maintenance Costs
Grid Benefits	Program Administration Costs
	System Removal

We also need to consider the time horizon of valuing the benefits and costs, as individuals have preferences for when benefits are received and costs are imposed. The time horizon is addressed by discounting. We discuss discount rates in more detail in Section 3.2.

It is important to note that benefits and costs are difficult to determine with a high degree of certainty. However, because we are evaluating an existing program with a significant amount of data available, we do have a unique opportunity to conduct a CBA capable of narrowing uncertainties and risk (i.e., probabilistic outcomes) in the evaluation of SGIP moving forward or similar incentive programs.

2. Overview of SGIP

For the sake of brevity, we have included a brief overview of the SGIP, taken almost entirely from the Executive Summary of the CPUC SGIP Sixth Year Impact Evaluation prepared by Itron, Inc.. We refer the reader to this report for a more detailed description of SGIP.

[3] CPUC SGIP Preliminary Cost-Effectiveness Evaluation Report, CPUC and Itron, Inc., September 2005.

SGIP was established in response to Assembly Bill 970 (AB970) and the CPUC issued Decision 01-03-073 on March 27, 2001 outlining the provisions of a distributed generation program. SGIP is currently the largest 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), microturbines (MTs), gas turbines (GTs), wind turbines, (WD), fuel cells (FCs), and internal combustion engines (ICEs). The incentives for DG technologies that rely on fuel (i.e., all except PV and WD) were further distinguished by the use of renewable and non-renewable fuel.

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 (PAs) at Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas (SoCalGas), and California Center for Sustainable Energy (CCSE). The PA at CCSE oversees SGIP installations in the San Diego Gas and Electric (SDGE) service area.

The number of projects and capacity by PA is shown in Table 2. In Table 3, the SGIP capacity and level of incentives received are shown by technology and fuel type as of December 21, 2006.

Table 2. Number of SGIP installations and corresponding installed capacity as of 12/31/06, separated by Program Administrator (PA).

PA	**# of Projects**	**Installed Capacity (MW)**
PG&E	439	105.1
SCE	244	46.2
SoCalGas	146	55.5
CCSE	119	26.8
Total	948	233.6

Table 3. Number of installations, installed capacity, and SGIP incentive payments separated by technology as of 12/31/2006.

Technology	Fuel	installations	Installed Capacity (MW)	Incentive Payments ($, millions)
photovoltaic	n/a	609	81.1	296.9
microturbine	non-renewable	98	13.8	non-renewable 77.9 renewable 9.0
	renewable		3.0	
gas turbine	non-renewable	3	11.6	
ICE	non-renewable	185	109.6	
	renewable		6.3	
fuel cell	non-renewable	8	5.8	13.2
	renewable		0.8	3.4
wind turbine	n/a	2	1.6	2.6
Total		905	233.6	403

3. Methodology and Analysis

3.1 Data and Data Sources

As mentioned previously, we are in a unique position to conduct a CBA using data collected since the program's inception in 2001. There are two primary sources of data used here: the PAs and Itron.

3.1.a Program Administrators and IOUs: Facility Data and Interconnection Data

The PAs for SGP 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 installed cost, the PAs 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[4] for more information]. Jack Faucett Associates (JFA) 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 Section 3.5.b.

In addition to the basic facility data, the IOUs and PAs 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

[4] Self-Generation Incentive Program Handbook, available from each IOU e.g., http://www.pge.com/includes/docs/pdfs/b2b/newgenerator/incentive/2008_sgip_handbook-r1-080516.pdf

(2001-2006). At the time of the preparation of this supporting material, we have received the requested information from both SDG&E and SCE, but not PG&E. These data are to be used by Rumla Inc. as part of their analysis of the transmission and distribution benefits of SGIP using the GE MAPS model. For a more detailed explanation of their approach and the GE MAPS model, please see Section 3.5.c.

3.1.b Itron: Metered Data and Reports

Itron Inc. has performed the metering and evaluation of SGIP since 2002. Itron provided TIAX with 15-minute averaged metering data for the facilities it has 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).

In addition to the metered data, the reports that Itron has prepared provide a wealth of aggregated information on SGIP.[5]

3.1.c Other Reports

Distributed energy resources (DER) have been studied thoroughly by a variety of state and government agencies, consultancies, and academic groups. Unless specifically referenced in this document, the studies that were used to inform our CBA and shape our approach will be listed in a bibliography.

With the State increasingly accounting for sustainability concerns in legislation,[6] we have opted to adopt an approach using a DDR in lieu of a SDR. We will draw from the academic literature, review case studies, and ensure that our approach avoids potential pitfalls and inconsistencies characteristic of applying DDRs.

3.2 Costs

In general, the costs associated with SGIP are straightforward. We have distinguished between them here as Private and Public costs. Both SGIP participants and the IOUs make up the Private group, whereas Public costs are those that are incurred by the government.

3.3 Benefits

We have grouped the benefits of SGIP that will be quantified in our CBA into three broad categories: environmental, macroeconomic, and grid benefits.

Environmental benefits are broadly characterized by the quantity of displaced emissions as compared to emissions from centralized power generation. Although in some cases, it

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[5] For instance, CPUC SGIP Sixth Year Impact Evaluation, prepared by Itron Inc. and submitted to PG&E, SGIP Working Group, August 2007

[6] Legislative language in both Assembly Bill 118, which established the Alternative Fuels and Advanced Vehicle Technology Fund, and the Low Carbon Fuel Standard (LCFS) make multiple references to sustainability.

is possible that there is a net environmental disbenefit i.e., emissions from the SG facility are greater than the emissions that would result from producing the same amount of power via central generation.

The macroeconomic benefits are based on the California I/O model and are a function of the money invested in the SG facilities in sectors such as construction (i.e., labor). The benefits may include the impacts on employment, output, income, state tax receipts and other selected variables. Impact analyses are always framed within the context of "with" and "without" (benchmark) perspectives. The impact of an exogenous event like the SGIP is defined and measured in terms of the differences between the state of the economy associated with the change and its state without.

The grid benefits are dominated by the market commodity worth (~90%), with the exception of heat and power considerations and on-site reliability applications. Furthermore, the T&D benefits are likely minute except in the cases where the SG installations are targeted by location.

3.4 Discounting

Discount rates are a standard economic practice to account for the higher economic value of benefits accrued today rather than tomorrow. For private investments (e.g., installation costs), we will employ a 7% discount rate recommended by the Office of Management and Budget (OMB). SGIP is a public program with public benefits e.g., reduced GHG emissions and public costs e.g., incentives paid. The social discount rate (SDR) applied to these benefits and costs over the time horizon is not as straightforward. There are several candidates, with the social rate of return on investment and the rate at which society values consumption at different points of time, the Social Rate of Time Preference (SRTP), as the most common. 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."[7] Furthermore 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 SDRs, some have advocated the utility of a declining discount rate (DDR) which declines with time, according to some defined function. As a result, the value of benefits to future generations is increased compared to standard methods of SDR.

3.5 Environmental Benefits

We employ a commonly accepted methodology for estimating the value of emissions reductions, and refer the reader to Section 7 of the US Environmental Protection Agency's (EPA) Office of Air Quality Planning & Standards Economic Analysis

[7] Groom, B; Hepburn, C; Koundouri, P; and Pearce, D. Declining Discount Rates: The Long and Short of it, Environmental & Resource Economics (2005) 32: 445-493.

Resource Document[8] for more detail. Furthermore, we employ a benefits transfer (BT) approach given that we don't have the luxury of time to conduct a sufficiently detailed analysis to value the environmental benefits of reducing harmful emissions. That said, a BT approach is neither passive nor straightforward; it requires informed judgment and expertise. As there is no accepted protocol for a BT approach, the following sections describe our logic in selecting the most appropriate studies and research to draw from in our analysis.

3.5.a Benefits as Reductions in Damages
We define benefits as reductions 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.

Direct damages to humans include both health damages and aesthetic damages. Health damages results 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.

3.5.b Emission Factors
In our approach, we will determine the lifecycle GHG emissions resulting from distributed and centralized generation. In the case of GHGs, we account for them 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

[8] OAQPS Economic Analysis Resource Document, April 1999, http://www.epa.gov/ttnecas1/econdata/6807-305.pdf

carbon emitted anywhere else. One could argue that the damages of climate change are not the same across states, nations, or continents; however, we are unaware of any research that estimates the damage costs of GHGs on a local, regional, or national scale. We will rely on existing research and analyses on the costs of damages resulting from climate change (i.e., the social cost of carbon).

In contrast to GHGs, we will determine the emissions of criteria pollutants 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 our analysis to monetize these emissions.

In a previous report for the Energy Commission,[9] 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, we compiled emission factors and efficiency factors for various combinations of equipment and fuels of interest. Furthermore, TIAX distinguished between in-state emissions and total emissions.

3.5.c Baseline Power Generation: Average verses Marginal
The selection of a baseline for the emissions of centralized power generation is a marginal verses average argument. If we opt to use a baseline for the average emissions of California's power generation, then we are assuming that SG installations are replacing existing loads. On the other hand, if we use a baseline for emissions based on marginal California power generation, we are assuming that the SG facility is providing power generation to a new load.

The average mix of California electricity is generated by the sources listed in Table 4, whereas marginal California power generation is defined as natural gas fired combined cycle combustion turbine (NG CCCT).[10] The lifecycle emission factors for criteria pollutants and GHGs for both average and marginal power generation are shown in Table 5, including the percent difference between them.

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[9] Full Fuel Cycle Assessment, Well to Tank Energy Inputs, Emissions, and Water Impacts, Consultant Report, TIAX LLC, CEC-600-2007-003, June 2007.

[10] 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-fired CCCTs; future long-term contracts for imported power will have emissions consistent with NG-fired 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).

Table 4. California's electricity mix as of 2006, as reported in the *Gross Systems Power Report 2006* by the California Energy Commission.

energy source	% of generation
natural gas	41.5
large hydro	19.0
coal	15.7
nuclear	12.9
geothermal	4.7
biomass	2.1
small hydro	2.1
wind	1.8
solar	0.2

Table 5. Lifecycle Emission Factors for centralized power generation, distinguished by the type of electrical generation (average verses marginal). We also include the emission factors on a lifecycle basis (total) and emissions taking place in California (California).

	emission factors (g/kWh)				%Δ	
	average		marginal			
pollutant	total	California	total	California	total	California
VOC	5.2E-02	4.1E-03	5.0E-02	1.0E-03	2%	74%
NOx	5.6E-01	1.1E-01	4.5E-02	4.5E-03	92%	96%
CO	3.3E-01	4.1E-02	1.3E-01	6.3E-02	62%	-54%
SOx	5.7E-02	3.6E-05	7.8E-02	0.0E+00	-37%	0%
PM2.5	9.3E-02	5.0E-03	1.0E-02	6.2E-03	89%	-25%
GHGs	530		505		5%	

We assume that self-generation is displacing marginal centralized power generation, defined here as a power plant natural gas fired combined cycle combustion turbine (NG CCCT).

3.5.d Benefits of Criteria Pollutant and PM2.5 Emission Reductions

It is beyond the scope of our work to perform a detailed analysis to determine the value of criteria pollutants, expressed as monetary damages per unit weight (e.g., ton) of pollutant. By comparing the emissions of SGIP facilities (where appropriate) to the emissions generated from centralized power generation in California, we can determine the displaced (or increased) emissions. We will use existing estimates for the monetized damages per ton of criteria pollutant. To obtain these estimates, we have reviewed previous studies and assessments that estimate damages.

3.5.e Social Cost of Carbon

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 SGIP's focus on renewable generation, it is important that we 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[11], 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.[12]

The IPCC Working Group II Fourth Assessment Report indicates that the SCC of carbon is increasing at an annual growth rate of 2.4%; however, Tol's meta-analysis (2007) finds no evidence to support this claim. In the most recent National Highway Traffic and Safety Administration (NHTSA) Draft Environmental Impact Statement (DEIS)[13], the agency opted to use the adder; however, in light of Tol's more recent findings, we will not.

Tol's updated analysis does not significantly change the "best estimates" of SCC, and therefore, we will use $12 per metric ton of CO_2.

Table 6. Damage costs for criteria pollutants and carbon dioxide (as a proxy for GHGs) for various categories. Note the year of the dollars. With the exception of CO_2, values are reported as dollars per (short) ton. CO_2 is reported as dollar per metric ton.

	health damages			**visibility**[1]	**indirect**[1]		
pollutant	AB2076[1] (2001$)	ARB[2] (2005$)	NHTSA[3] (2006$)	(2001$)	agriculture (2001$)	materials (2001$)	forests (2001$)
VOC	5,000	4,400	1,700	47	300	400	110
NO_x	3,200		3,900	1,000			
NO_x (as PM)	84,700	18,855	--	--	--	--	--
PM2.5	352,000	618,395	164,000	--	--	--	--
SO_x	--	--	16,000	3,900	--	--	--
CO_2	16.5	--	7.0	--	--	--	--

[1]**AB2076**: California Strategy to Reduce Petroleum Dependence, Appendix A: Benefits of Reducing Demand for Gasoline and Diesel, Consultant Report , P600-03-005A1, September 2003
[2]**ARB**: Emission Reduction Plan for Ports and Goods Movement, Appendix A: Quantification of the Health Impacts and Economic Valuation of Air Pollution from Ports and Goods Movement in California, March 2006
[3]**NHTSA**: Draft Environmental Impact Statement: Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011-2015, Appendix C, NHTSA, June 2008

3.6 Macroeconomic Benefits

The macroeconomic benefits of our CBA require an explicit or implicit model that explains how the economy is affected by a variety of factors determined outside the control of private decision makers. Because there is a wide range of opinions on the likely direction of energy use, it may be wise to define alternative benchmark scenarios. Many issues must be considered in the benchmark world: What responses are expected to increasing scarcity of fossil fuels? Will higher prices stimulate energy conservation?

[11] Tol, RSJ. The marginal damage costs of carbon dioxide emissions: an assessment of the uncertainties. Energy Policy, 33 (2005), 2064-2074.

[12] Tol, RSJ. The Social Cost of Carbon: Trends, Outliers, and Catastrophes. Economics E-Journal, Discussion Paper 2007-44, 2007.

[13] Draft Environmental Impact Statement: Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011-2015, Appendix C, NHTSA, June 2008

Will current movements toward alternative fuels like ethanol fuel, hydrogen and fuel cells accelerate? Will high costs of energy spur increased exploration for fossil fuels and new methods of extraction? Will high energy costs sustain a shift toward renewables and nuclear? These possibilities must be spelled out in the benchmark scenario because the impact of SGIP is not the only way today's world and California will be different from an alternative fuel driven economy in the future. The benchmark scenario changes will proceed in a dynamic fashion, the pace of which will be crucial in defining the impact and viability of the California economy under any future scenario.

Several types of impact models have been developed in economics. One of the most widely used economic tools in modeling "with" and "without" scenarios is the set of models referred to as input-output (I-O) models, which were developed explicitly for impact analysis. I-O models describe the world in a general equilibrium framework, in which all segments of society are interrelated and affect one another, even though some connections might be relatively minor.

An alternative to an I-O model is a computable general equilibrium (CGE) model, which uses production functions that allow substitution among inputs as their prices change. Ideally CGE models are superior to I-O models because they allow for price response in production, but in practice they have demanding data requirements, and even then achieve far less industrial disaggregation than I-O models confer, up to some 500 sectors. A 50-industry CGE model would be very large but its ability to distinguish the production details of gasoline refining from those of ethanol, hydrogen or other alternative fuels production would be limited, and the distinctions obtainable could be largely guesswork. Regional disaggregations would be even more problematic because of the proliferation of production parameters that would need estimating.

Due to time constraints and concerns regarding the magnitude of macroeconomic impacts (which in the event that they are small, will be indiscernible with a CGE model), we opt to use an I-O model.

3.6.a Description of Input-Output Models

One way to develop estimates of some of the benefits of the SGIP is to investigate the economic impacts of the program's expenditures. This is useful because once a program's benefits and costs are known, cost-benefit analysis can be used to meaningfully evaluate and compare different programs.

Inter-industry economic I-O models use a matrix representation of a nation's or region's 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 options. 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 interregional 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. A description of IMPLAN's social accounting and multiplier features is provided below:

3.6.b Social Accounting
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.

3.6.c Multipliers
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 the given industry, 18 total jobs (in all sectors) would be added to the given economic 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: 1) the direct, 2) the indirect, and 3) the induced effects. The direct effect is the known or predicted change in the local economy that is to be studied. For example, if a manufacturing company hires 40 employees, the manufacturing industry gains 40 employees. The indirect effect is the business to business transactions required to satisfy the direct effect. For example, because a manufacturing company is closing, they will no longer have a demand for locally produced materials needed to produce their product. This will affect all of their suppliers. Finally, the induced effect is derived from local spending on goods and services by people working to satisfy the direct and indirect effects. Furthermore, it measures the effects of the changes in household income. For example, employees hired by a company

may increase their expenditures in restaurants and shops since they are employed. These changes affect the related industries.

The expenditure categories in the SGIP were provided by the California utilities. These estimates include disaggregated information on expenditures by technology and geographic region. The disaggregation of the expenditure categories is useful because technology and region specific expenditures and associated benefits can be evaluated and compared.

In order to run the collected data for the various expenditure categories through the input-output 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 covert 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 are provided in Tables 7 and 8, respectively.

The sector assignments for equipment categories in Tables 7 and 8 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 economist, will be subtracted and assigned to the appropriate whole and transportation sectors to account for those economic sectors properly.

Table 7. Assignment of Eligible Project Costs to NAICS Codes and IMPLAN Sector Codes

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		Seles 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

Table 8. Assignment of Ineligible Project Costs to NAICS Codes and IMPLAN Sector Codes

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		
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	
4	Thermal Load Costs (new absorption chillers, boilers, etc.)		332410	Power Boiler and Heat Exchanger Manufacturing	238	
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

3.6.d Example of IMPLAN Outputs:
Specific economic impacts captured by the IMPLAN model include:

- Value added
- Jobs created (full time equivalents)
- Payroll compensation
- Federal tax revenue
- State and local tax revenue

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 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 difficult 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 costs. Other project benefits are added to these to estimate the total benefits. Once the total benefits of a project have been determined they can be compared to the costs of the project by performing a CBA.

3.7 Grid Benefits (T&D)
Understanding the impacts on the electrical grid of distributed generation is difficult. We will employ General Electric's Multi Area Production Simulation Software (MAPS™) program to analyze the grid impacts and throughput of the SGIP installations. Using GE's MAPS software, we will integrate detailed representations of the SGIP system's load, generation, and transmission into a single simulation. This enables us to calculate hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation. The MAPS program is the first commercial Socially Constrained Economic Dispatch (SCED) simulation tool and has been used recently by Rumla, Inc. in an Energy Commission-sponsored assessment of the effects of high levels of deployment of intermittent resources.

There are two wholesale market developments that cannot be ignored in the evaluation of the SGIP: 1) The on-going implementation of the Market Re-design and Technology Update (MRTU) by the California Independent System Operator (CAISO); and 2) the institution of the Resource Adequacy (RA) requirements for the investor-owned utilities (IOUs) by the CPUC.

The MRTU represents a sweeping overhaul of the structure and operation of California's electricity markets. It is expected to be implemented by the end of this year. The new market protocols, rules and procedures will directly determine the valuation of most of the components of avoided costs. Our approached, based on the MRTU's market platform will generate realistic and spatially detailed forecasts of avoided cost estimates instead of the largely symbolic area-wide projections.

RA requirements determine the capacity needs of each IOU. It will also facilitate the development of a pricing regime for generating capacity. Moreover, the enforcement of RA requirements is expected to influence market clearing prices significantly in and out of the CAISO control area. Embracing the RA regulation will enable us to determine capacity benefit values as AC components separate from AC energy projections. Ignoring the RA regulation eliminates the need to rely on using the combined cycle gas turbine (CCGT) costing proxy to generate bundled energy-capacity AC values; a result that contravenes established market rules and trends.

Combined together, the MRTU and the RA developments should, on average, determine more than 95% of the total value of the avoided costs for SG installations. Even though earlier SG programs have preceded the establishment of the MRTU and RA requirements, excluding these developments from a cost-benefit analysis of investments with an economic life exceeding ten years is unjustifiable.

3.7.a Local Energy Efficiency (EE) and Self-Generation (SG) Markets
SG applications are driven by customer goals and project-specific economics. There will always be significant variations in SG profitability profiles spanning low-hanging fruits, potentially economical investments, marginal opportunities, and many cases where substantial subsidization would be needed. The differences reflect several factors, such as the need to serve thermal loads (i.e., the opportunity to cogenerate), customer reliability assurance, and siting constraints. Relying on T&D planning area and temperature based differentiation of incentives is not likely to lead to the most desirable results. A more granular approach is needed; a more appropriate methodology will be employed here.

To remain consistent with market realities discussed above, we need to also consider the following significant avoided cost benefits of self generation: (i) Congestion mitigation i.e., the reduction or avoidance of transmission congestion; (ii) Grid marginal loss benefits; and, (iii) Local reliability value.

(i) Congestion Mitigation:
Transmission congestion occurs whenever scheduled power flows on a line or a path exceed the available transfer capability (ATC) on that line or path. When this happens, the grid operator (the CAISO in this case) invokes a congestion management scheme that creates an energy price differential across the congested line or path, making the price of electric power higher at the delivery end. Such occurrences expose ratepayers in the congested areas to price increases that can be exorbitant.

There are three ways for mitigating congestion cost risks: (a) Use available financial hedging mechanisms, (b) Invest in transmission upgrades; and, (c) Reduce the need to import power over the congested line or path. The third method requires investing in local power plants and/or in localized resources that may include EE, SG and DG options. In spite of the variation in the options available for managing congestion risks, they all share a common valuation mechanism: the expected cost of transmission congestion. For localized resources, such as SG, this translates into an avoided cost of transmission congestion that can be substantial.

(ii) Grid Marginal Losses Benefits:
Under the MRTU, CAISO will use a locational marginal pricing (LMP) platform to manage electricity markets and operate the grid for all three IOUs and a few municipal systems. The new regime will determine hourly and sub-hourly prices on a bus-specific basis (nodal prices) that could differ substantially spatially and temporally because of potential transmission congestion and location-dependent marginal losses. There will be times when congestion does not take place anywhere on the grid but marginal losses are ubiquitous. Price signals under the MRTU will always be spatially differentiated because of the marginal loss component of nodal prices.

The approach that the CAISO has adopted to determine marginal losses contributions to price differentiation will depress bus prices far from load centers and increase those close to them. The resultant marginal losses modifications could vary at any point in time by more than ±10% of the base commodity energy price. In currency terms, wholesale energy prices could differ locationally by more than $20/MWh (2 cents per kWh). Policy makers have to incorporate the marginal loss factor in the design and assessment of EE, DG and SG incentive programs.

(iii) Local Reliability Value:
SG 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.

3.7.b Spatial Resolution of Avoided Cost Information
In spite of setbacks, the electric industry will continue to trend towards greater spatial and temporal differentiation of price signals. In restructured markets such as California's, this movement has progressed sufficiently far such that a return to flat price profiles is unlikely. This outlook encourages location-sensitive investments in customer-based resources such as EE and SG technologies. Incentive programs for encouraging wide EE and SG adoption by consumers must take full advantage of available information on spatial and temporal price variations. Failure to achieve this requirement ensures ineffective program designs and implementation.

Price differentiation by location and time must be carried out for each of the three basic stages of serving electricity customers:

- Wholesale power supply
- Delivery over the transmission system to distribution takeout nodes
- Delivery over the distribution circuits to consumers.

(i) Wholesale Power Supply:
In the CASIO-operated markets, resources compete under a mix of uncertainties associated with their own circumstances and others that pertain to transmission

constraints, electricity demand variations, and the availability and bid prices of competing generation. The competition produces hourly profiles of market clearing prices (MCPs) that are essential to proper valuation of the largest component of avoided costs. Such MCP profiles cannot be adequately mimicked by using proxy resource techniques augmented with shaping factors borrowed from another environment. Contouring annual avoided generation cost values by using outdated price profiles from a short-lived (and now defunct) market arena does not convey credible temporal resolution of future AC values.

(ii) Transmission Service:
For this stage of electric power service, we are concerned with the degree of the spatial and temporal resolution of the total avoided cost of transmitting wholesale generation from its sources to the distribution takeout points. This cost consists of two components:

- CAISO charges for delivering energy from its sources to take-out distribution points; and
- The costs of the transmission infrastructure needed for delivering the energy.

(ii)-(a) CAISO Charges:
The grid operator collects a number of volumetric charges for delivering power to load-serving entities that can be classified under the following categories: (1) Congestion management; (2) Marginal losses; (3) Ancillary services; and, (4) Grid control, operation, and management.

The first two, congestion management and marginal losses, are by far the most important both in terms of relative contributions to the cost of delivered wholesale generation and their propensity towards spatial and temporal dispersion. The effects of the fourth category are expected to be small both in terms of magnitude and impacts on the locational and temporal variations of ACs. Moreover, the benefits from any avoided costs would be limited to the participant(s) in the EE and SG programs (since the costs of CAISO's services are not avoidable for the rest of ratepayers).

(ii)-(b) Transmission Infrastructure Costs:
These costs encompass charges for existing transmission plant cost recoveries and to pay for future system expansion and upgrading needs. If a self-generator were able to avoid existing plant charges, the avoided costs will be shifted to remaining customers. Since utilities usually have special tariff provisions to ensure such unintended consequences of SG installations are minimized, we will not be concerned with this category of transmission costs. Our focus is instead on transmission system expansion and upgrading that may or may not be reduced by investing in localized resources.

Deferring transmission projects by investing in distribution-level measures such as EE, SG and DG technologies is unlikely to be successful for the following reasons:

The lumpiness problem: Transmission investments often involve moving power over high-voltage networks on a large scale measuring in the hundreds if not thousands of MWs. This leads to two difficulties. First, the network nature and the size of transmission projects discourage assigning them to any particular planning area or areas. Secondly, the size and the logistics of carrying out the investments in localized resources that would be needed to ensure effective deferment of targeted transmission project(s) may require imposing draconian government measures.

The moving target problem: Grid upgrades are driven by many factors that often interact in complex and unpredictable ways both physically and in the regulatory arena. In many cases, the sponsoring utility has little control over key developments in the planning process and has to act in partnership with other(s) to enhance project success. This environment is prone to complicate significantly an already difficult situation for planning and implementing large-scale area and utility-wide investments in localized resources. The uncertainties and associated risks can be substantial.

The strategic value problem: Certain transmission investments are partially motivated by long-term strategic considerations that cannot be addressed by investing in localized resources.

(iii) Distribution Service:
Unlike the transmission stage, there are no CAISO charges to contend with at the distribution level. Here, we are mainly concerned with the deferability of distribution system investments using SG installations. Deferring distribution upgrades by investing in EE and SG programs is not as tenuous as in the case of transmission projects. The much smaller carrying capacities of distribution circuits reduce the lumpiness problem. The moving target issue is also not as severe. And strategic investment considerations are not as common as in the case of transmission planning. Nevertheless, deferring distribution upgrades and earning AC credits for EE and SG programs cannot be systematically achieved on large scales except in rare cases. A more probable path to success is to pursue high value applications, picking the lowest hanging fruits first and proceeding progressively to the next eligible locations. In over 25 utility studies of DG applications, we have found that the most economic cases involved distribution circuits requiring immediate upgrading to serve very slow growing loads.

In principle, we want to avoid using an approach to configure incentives (or part of incentives) by using area-wide deferral AC values. This approach may produce inefficient and inequitable SG investments. Granting deferral credits to anyone who wishes to participate may lead to 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 programs but do not offer comparable distribution upgrading deferral savings would be rewarded inequitably under area-wide postage stamp approaches.

4. SGIP Moving Forward

4.1 Review of Advanced Technologies

Effective January 1, 2008, the eligible technologies for incentive funding under the SGIP will be limited to fuel cells and wind distributed generation technologies.[14] 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[15] specifically provides for adding new technologies to the program, and has established guidelines for doing so.[16] In a study of distributed generation (DG) technologies performed by Arthur D. Little for EPRI in 1999,[17] the list included microturbines (MTs), combustion turbines (CTs), reciprocating internal combustion engines (ICEs), Stirling engines, several fuel cell technologies, and energy storage. The DG update performed by TIAX LLC for EPRI in 2005[18] confirmed this list as the only foreseeable candidate technologies. As MTs, CTs, and ICEs were formerly SGIP eligible, and fuel cell technologies remain eligible, our focus turns to the Stirling engine and energy storage. These are discussed in the following subsections. A brief discussion of renewable fuels is also included as it was thought that engine and turbine technologies operating exclusively on renewable fuels could see renewed interest and restored eligibility.

4.1.a 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.[19] As the minimum size for currently incented SGIP systems is 30 kW per site, multiple Stirling engine generators would be needed to qualify. These multi-generator systems are largely unproven and likely quite costly.

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[14] Assembly Bill No. 2778, September 2006.

[15] Self Generation Incentive Program Handbook, May 16, 2008 - REV 1 http://www.pge.com/includes/docs/pdfs/b2b/newgenerator/incentive/2008_sgip_handbook-r1-080516.pdf.

[16] Self Generation Incentive Program Modification Guideline (PMG), July 1, 2006, Revision 2, http://www.pge.com/includes/docs/pdfs/b2b/newgenerator/incentive/program_modification_guideline.pdf.

[17] Casten, S., Assessment of Distributed Energy Resource Technologies, EPRI Report TR-114180, December 1999, http://www.epriweb.com/public/TR-114180.pdf.

[18] Teagan, W.P., Technology Review and Assessment of Distributed Energy Resources: Distributed Generation, EPRI Report 053828, October 2005.

[19] Ibid.

4.1.b Energy Storage

As shown in the avoided cost analysis discussed in Section 3.5.c, 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 should be considered a candidate for the SGIP. Studies have been performed on hybrid PV-battery storage[20] and FC-battery storage systems,[21] 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 (CAES), super-conducting magnetic energy storage (SMES), pumped hydro, super capacitors, and hydrogen generation and storage. However these alternate storage technologies are generally not appropriate for consideration as SG technologies. Pumped hydro and CAES are utility scale storage technologies having usual capacities in the several tens to several hundreds of MW range. Flywheel, SMES, 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 SG 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 that could find ready use in SG applications:[22,23]

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

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[20] Energy Storage: Role in Building-Based PV Systems, TIAX LLC, Report to U.S. DOE under Contract DE-AD26-06NT42833, March 2007.

[21] Zogg, R., and S. Casten, Preliminary Assessment of Battery Energy Storage and Fuel Cell Systems in Building Applications, Arthur D. Little, Report to the National Energy Technology Laboratory, U.S. DOE under Contract GS-23F-8003H, August 2000.

[22] Rastler, D., and B. Steeley, Electric Power Research Institute's Distributed Generation and Energy Storage Program, presentation to the California Energy Commission Integrated Energy Policy Report Workshop on Emerging Technologies for the Integration of Renewables, July 31, 2008, http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-31_workshop/presentations/Distributed_Energy_Resources_to_Increase_System_Renewables-Steeley.pdf.

[23] Teagan, W. P., Technology Review and Assessment of Distributed Energy Resources, Distributed Energy Storage, TIAX LLC, Final Report to EPRI, January 2006.

4.1.c Alternative and Renewable Fuels

As noted above, the changes in the SGIP, effective January 1, 2008, limit incentives to fuel cells and wind generation technologies. Thus, even renewable fuels can only be used in conjunction with a fuel cell technology to be SGIP eligible. It is possible, however, that the formerly eligible engine and turbine technologies 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 transesterification 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