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CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report

Submitted To:

California Public Utilities Commission
Energy Division

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Executive Summary

1.1 Introduction

This report summarizes the findings of the first cost-effectiveness evaluation of the California Self-Generation Incentive Program (SGIP). The SGIP is a statewide[1] program developed by the California Public Utilities Commission (CPUC) to provide incentives for the installation of certain renewable and clean distributed generation (DG) technologies serving all or a portion of a facility's electric needs. DG technologies involved in the SGIP include photovoltaic (PV) systems, reciprocating internal combustion (IC) engines, micro-turbines (MT), fuel cells, and wind turbines.

The purpose of this study is to assess the cost-effectiveness of the program at the 2004 program year stage of implementation. It should be recognized that the cost-effectiveness results in this study are based on SGIP-specific projects and incentive structures. As such, the results may not be reflective of the current performance or costs of DG technologies or those employed in other settings. Similarly, care should be taken in trying to gauge the performance or cost-effectiveness of DG technologies in general from these results.

Cost-effectiveness is assessed based on a recently developed cost-effectiveness analysis framework report[2] using metered project performance information from the Program Year 2004 Impacts Report. In accordance with that framework, cost-effectiveness is evaluated from three perspectives:

- Participants (project owners within the SGIP),
- Nonparticipants (ratepayers), and
- Society as a whole.

The Participant Test evaluates the benefits and costs of the SGIP from the perspective of participants. From this perspective, the participant's costs of owning and operating the SGIP

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1 Available in the service territories of Pacific Gas & Electric, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric.

2 Itron, Inc., *Self-Generation Incentive Program: Framework for Assessing the Cost-Effectiveness of the Self-Generation Incentive Program*, prepared for the California Public Utilities Commission, March 2005.

system are compared against the retail energy costs that would have been incurred by the participant had they continued to obtain all of their electricity from a utility company.

The Nonparticipant Test evaluates the costs and benefits of the SGIP from the perspective of utility customers that did not participate in the SGIP. This test is sometimes called the Ratepayer Impact Measure (RIM) Test because its principal objective is to measure what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

The Societal Test evaluates the costs and benefits of the SGIP from the perspective of all members of society. This test is a variant of the total resource cost (TRC) Test typically used by the CPUC in evaluating demand-side management programs. The TRC Test assesses program cost-effectiveness from the combined perspective of all utility customers (participants and nonparticipants).[3] Typically, only a TRC test or a Societal test is conducted to examine this type of cost-effectiveness perspective. However, a TRC test is included as Appendix F to the report to provide additional information to the societal perspective.

It is important to note that results of any cost-effectiveness evaluation are directly related to the underlying analysis framework. In this case, the SGIP-specific framework was meant to be implemented in the near term to conduct an initial assessment of the program's cost-effectiveness. A number of issues, including classification and valuation of benefits and costs within the different tests, have surrounded discussion of the framework. However, the framework development and implementation schedule did not permit the opportunity to reach consensus and closure on some of these issues. Consequently, findings and conclusions made in this report could change significantly with modifications in the framework and should be viewed in that context.

A number of benefit and cost components are used in conducting cost-effectiveness tests. Section 3 describes how the components used in the evaluation are calculated. Sections 4 through 6 provide more detailed discussion of what components are used in each of the tests.

The Commission issued interim ruling R.04-03-017 adopting general policies and principles for cost-benefit methods for evaluating DG facilities.[4] Among the adopted policies and principles were the following:

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[3] The Societal Test differs from the TRC in that the Societal Test ignores tax credits, considers externalities that impact society as a whole, and makes use of a societal discount rate that is usually lower than the private discount rate employed in the TRC test.

[4] California Public Utilities Commission, *Interim Opinion Adopting Cost-Benefit methodology for Distributed Generation,* R.04-03-017, September 6, 2005

- DG projects should be analyzed using a societal test, a non-participant test and a participant test,
- The avoided costs presented by E^3 and adopted in D.05-04-025 for energy efficiency projects should be applied to DG projects, with some modifications, until the Commission has adopted avoided costs for DG facilities in that proceeding,
- The impacts of DG projects on market prices should be included as a benefit in the societal model,
- All relevant environmental benefits should be included in the cost-benefit models, whether or not their impacts result from regulation or compliance with state or federal laws,
- Tax incentives, standby charge exemptions, and Self-Generation Incentive Program (SGIP) incentives should be considered benefits to DG projects in the participant tests and costs in non-participant tests, and
- The value of DG projects in terms of "market transformation" should be considered in R.04-04-025.

The framework and treatment of benefits and costs in this evaluation are consistent with the interim ruling with the following exceptions:

- Environmental benefits included in the evaluation were limited to CO_2 and NOx (e.g., excluded environmental benefits that could be accrued from reduced waste disposal), and
- Did not include market transformation impacts.

Table 1-1 on the following page shows how the various benefit and cost components are allocated in the three tests of this cost-effectiveness evaluation.

Table 1-1: Cost and Benefit Components for Each Test

Test	Costs	Benefits
Societal	External environmental costs from operating SGIP facilities	Avoided grid generation costs (avoided electricity costs)
	System installed costs (Includes: emission controls, interconnection, and emission offsets)	Avoided T&D capital deferral costs
	System O&M costs	Reliability net benefits
	SGIP administration costs	Reduced line losses
	DG fuel costs	External environmental benefits ■ CO_2 (only for grid generated electricity) ■ NO_x and CO_2 for avoided natural gas (from host site boilers)
	System removal less salvage value	Market Price (elasticity) Impacts
		Avoided host site natural gas fuel costs (from waste heat recovery)
Participant	System installed costs (Includes: emission controls, interconnection, and emission offsets)	Reduced electricity bills (deferred retail rate electricity)
	System O&M costs	Host site natural gas fuel costs (from waste heat recovery)
	DG fuel costs	Incentives from SGIP & other programs
	Nonbypassable Charges	Tax credits
		Depreciation benefits

Table 1-1: Cost and Benefit Components for Each Test (continued)

Test	Costs	Benefits
Nonparticipant	*Electricity ratepayer costs*	*Electricity ratepayer benefits*
	■ SGIP costs ■ Decreased sale of electricity to participants ■ Reduced electric T&D revenue	■ Avoided grid generation costs ■ Avoided T&D capital deferral costs, and reduced line losses ■ Reliability net benefits ■ Price (elasticity) benefits
	Gas ratepayer costs	*Gas ratepayer benefits*
	■ SGIP costs ■ Decreased revenues from transportation of fuel for boilers ■ Increased utility cost of transportation of fuel for natural gas-fired SGIP systems	■ Increased revenues from transportation of fuel for natural gas-fired SGIP systems ■ Decreased cost of transportation of fuel for host-site boilers

Due to the nature and scope of a statewide cost-effectiveness assessment, certain items have not been considered. Among the items not covered by this cost-effectiveness evaluation are market transformation impacts, energy security benefits, effects of increased power quality, and site-by-site assessments of costs attributable to the program. Including these items in future analyses could significantly alter the results.

1.2 Results

Results of the preliminary SGIP cost-effectiveness evaluation are summarized in Table 1-2. These results indicate that the SGIP, as a portfolio of projects, is cost-effective from the participant perspective, but cost-effectiveness declines significantly when viewed from the nonparticipant, TRC, or societal perspectives. Within technology classes, cogeneration systems maintain a higher benefit-to-cost ratio than do PV systems in the Nonparticipant, TRC, and Societal tests. This gap is narrowed in the Participant test. Moreover, IC cogeneration systems maintain a relatively high benefit-to-cost ratio across all perspectives. The highest benefit-to-cost ratio (1.58) estimate is calculated for biogas systems viewed from the participant perspective.

These results are not unexpected in light of the emerging status of most of the SGIP technologies, with their associated high capital costs. As technologies mature, installed capital costs are likely to decrease and therefore drive up benefit-to-cost ratios. For example, system average costs for PV systems installed in the SGIP for the 2004 reporting year are significantly higher than current PV system costs in other settings. Similarly, viewed from a portfolio perspective, growth of SGIP-incentivized distributed generation systems may continue to add benefits to the electricity system overall, including greater potential for deferred T&D and increased ability to meet localized and system peak demand. Consequently, it may be useful to view these early cost-effectiveness results of the SGIP as a starting point from which parties can begin to shape the future direction of the program.

Table 1-2: Program Benefit-Cost Ratio Results[5]

	Perspective/Test (Base Case)			
Technology	**Society**	**TRC**	**Nonparticipants**	**Participants**
PV	0.27	0.23	0.25	0.88
Biogas	0.74	0.61	0.33	1.58
Cogeneration (all)	0.72	0.63	0.56	1.05
IC Engine	0.75	0.65	0.57	1.08
Microturbine	0.54	0.48	0.55	0.81
Total (Wtd.Avg.)	**0.59**	**0.50**	**0.48**	**1.02**

Results in Table 1-2 can be viewed as comprising a base case. In particular, the results exclude possible net benefits related to electric system transmission and distribution (T&D) cost savings. The rationale for this exclusion in the base case is discussed in the SGIP Cost-Effectiveness Framework Report.[6] In addition, the results reflect maintenance costs and performance factors that are based on available metered operating performance during their early years and therefore these parameters may be considered conservative. For this reason an *Optimistic case* was developed for each technology that includes the T&D benefits, as well as other more favorable assumptions about system performance and maintenance costs. The base case (lower bound) and optimistic case (upper bound) benefit-cost ratios for the societal and participant perspectives are illustrated in box plot format in Figure 1-1.

Several important observations can be made in reviewing the bracketed results. First, the benefit-cost ratio for the portfolio of SGIP projects increases by over 33 percent under the Optimistic case, suggesting that performance and cost factors considered under the Optimistic case may provide benefits across the range of SGIP technologies. Second, biogas

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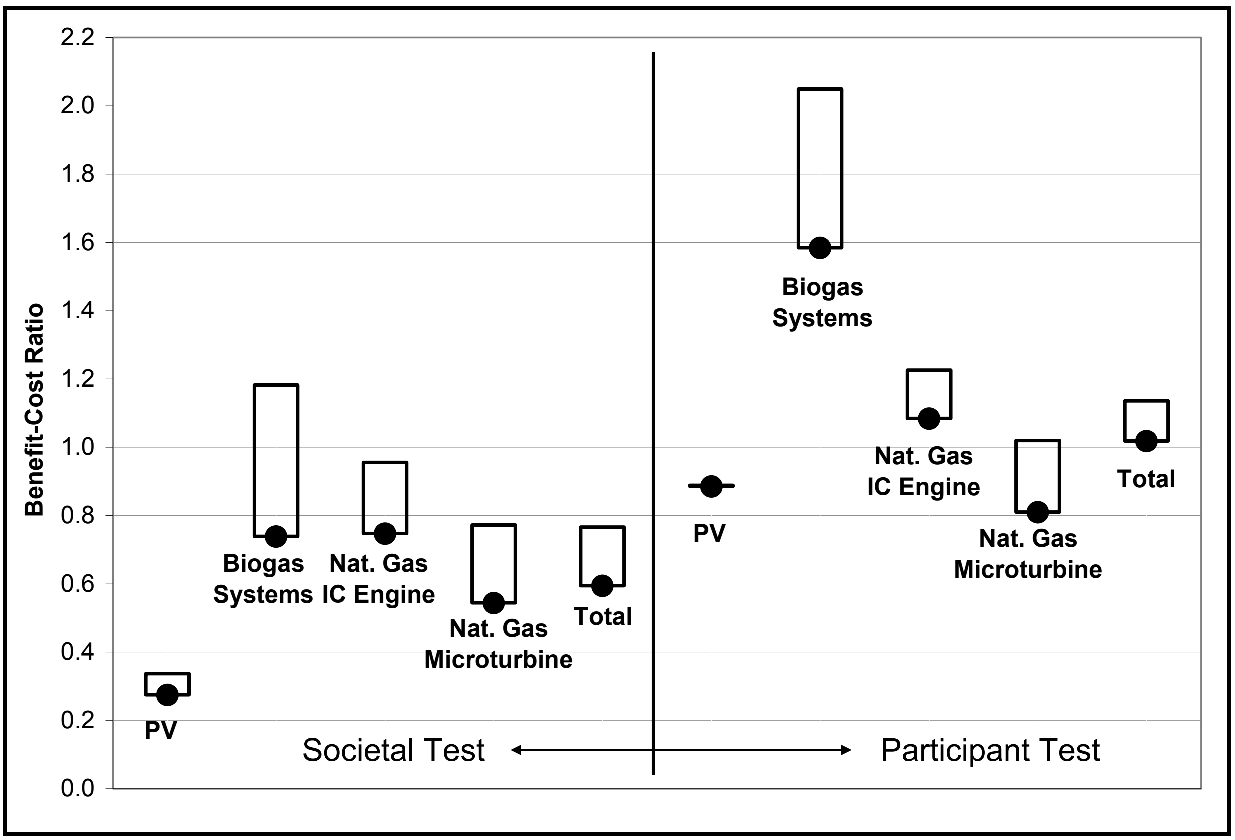
[5] The framework considers only three tests: societal, non-participant and participant. A TRC test is included here only to provide additional information and perspective.

[6] It should be noted that contradictory provisions in part exclude T&D benefits from accruing to SGIP DG projects. In D.03-02-068, one of the conditions DG systems must meet to provide T&D benefits is the requirement that the DG system be accompanied by "contractual physical assurances". However, in D.01-03-07, DG projects that have contracts to provide distribution support are ineligible to receive SGIP incentives.

systems have the most significant changes in value from Base to Optimistic cases and are the only technology for which Optimistic case benefit-cost ratio estimates exceed one from the societal perspective. These high and wide benefit-cost ratio ranges for biogas systems may be due to relatively high capacity factors, captive renewable fuel supplies (which eliminates their need to purchase fuel, and, more importantly, avoids volatility in fuel prices experienced with natural gas), and a relatively modest increase in installed system costs over natural gas-fueled systems. Lastly, natural gas microturbines are the only technology for which the switch from Base to Optimistic assumptions results in participant test results moving from less than one to greater than one. This increase in benefit-cost ratio for microturbines is largely due to assumptions in the Optimistic case that decreased maintenance costs will occur with maturing of the technology, as identified in Appendix A.

Figure 1-1: Societal and Participant Test Benefit-Cost Ratios – Sensitivity Analysis



The principal question motivating this evaluation can be simply stated as: "*Is the SGIP cost-effective?*" The simplest answer to that question is: "*For this present group of operational projects, not during the 2004 timeframe*" because the benefit-cost ratios from the societal and nonparticipant perspectives for the group as a whole are substantially less than one. However, lifecycle economic analyses—particularly from the societal perspective—are not simple. Important elements of complexity that must inform interpretation of these results include:

- Certain societal benefits were not included because they were too difficult to quantify. These benefits include demonstration and market inducement effects, energy security benefits, and, for PV systems, power quality benefits (e.g., the ability of PV inverter systems to reduce disturbances in voltage and frequency).
- For certain participants, cogeneration provides increased electrical power reliability, which can be an important electric customer benefit for some industries that was not included in the analysis.

Several key factors limit the accuracy of quantitative results, as well as qualitative conclusions that can be drawn at this time. These limiting factors include:

- For cogeneration systems, availability of metered overall system performance data—particularly useful recovered heat data—is limited to a relatively small sample of operational systems.
- SGIP systems typically have a 20-year facility economic life, however; necessarily in all cases less than two years' operating experience was available upon which to base estimates of life-cycle economic performance.
- There appears to be a trend toward incorporating heat recovery chillers into cogeneration systems, which may lead to increased average heat recovery rates and improved system economics.
- The natural gas prices faced by cogeneration system owners during periods of the analysis period were quite high and variable, causing an unusual spread between electricity rates and gas prices. This is especially important in that volatility in natural gas prices is not necessarily reflected in electricity prices (i.e., most cogeneration facilities purchasing natural gas have market-based contracts that require them to pay (e.g., "see") higher natural gas prices which are not being reflected in electricity retail rates). SGIP systems that do not purchase or displace natural gas (e.g., PV, biogas, and wind systems), but receive value based on avoided electricity generation costs are affected to a similar, but lesser degree by this spread.
- There is a high degree of uncertainty regarding future retail electricity and natural gas prices. The electricity price projection used in this analysis is much lower than the historic trend for the past 20 years.

Moreover, it is important to recognize that the current results represent only a snapshot in time. Given the substantive changes likely to occur with future SGIP systems (e.g., increased efficiency of microturbines, better air pollution control for IC engines, and lower costs of PV system components), the level of program cost-effectiveness may change significantly.

1.3 Conclusions and Recommendations

Conclusions

Notwithstanding the limitations of this analysis noted above, several conclusions about the program's cost-effectiveness can be drawn based on this initial assessment:

1. The SGIP appears to be cost-effective with respect to participants, but there is a noticeable drop in cost-effectiveness for the nonparticipants or society as a whole.
2. Biogas systems have among the highest benefit-to-cost ratios in the Participant, TRC, and Societal tests.
3. Cogeneration and biogas systems generally have higher benefit-to-cost ratios than PV systems from a societal perspective.
4. Within cogeneration systems, IC engine-based systems are more cost-effective than microturbine systems.
5. If electric system T&D benefits are included, and several other favorable scenario assumptions are made, the cost-effectiveness of the SGIP is markedly improved. However, the cost-effectiveness of the program is still doubtful from the nonparticipant and societal test standpoint when viewed at the 2004 year stage in the program's development.
6. Major uncertainties with regard to future energy prices and long-term system performance make an absolute definitive cost-effectiveness determination impossible at this time.

Program Recommendations

In light of the cost-effectiveness results to date, the CPUC's Energy Division and other program stakeholders should consider the potential costs and benefits that could result from the following targeted analyses:

- Investigate the relationship between climate zone and cost-effectiveness of the program and the various SGIP technologies. In particular, determine whether the SGIP is more cost-effective in hot inland areas, where there may be increased distribution system daily peak load and annual demand growth. Similarly, determine and identify what differences exist between the cost-effectiveness of SGIP technologies in these areas, and how significant increases in different technologies (e.g., PV or other renewable-fueled systems) may impact the Program's cost-effectiveness.
- Examine the relationship between those geographical areas where local electricity transfer congestion poses a problem and assess the cost effectiveness of using various SGIP technologies in those areas of T&D congestion. Sensitivity analyses

could indicate future impacts of deploying additional SGIP within these congested areas and assess the cost-effectiveness under the different framework tests.

- Conduct sensitivity analyses to assess the impacts of improved performance or reduced capital and/or operating costs on the cost-effectiveness of the SGIP and its eligible technologies. Among the components that could be considered are improved heat recovery rates for chillers on cogeneration technologies; PV battery backup and DC output circuits that allow continued operation of such items as lighting or computers in commercial businesses; variations in natural gas prices, adoption of new air pollution control equipment on IC cogeneration projects; and the incorporation of selected new technologies to the program.
- Discrepancies between natural gas prices and realized electricity prices mask a precise assessment of the cost-effectiveness of the SGIP and program-deployed generation technologies. Future cost-effectiveness evaluations should employ electricity price projections (or sensitivity analyses) that allow for a more market-dynamic response.
- The Energy Division should investigate the discrepancies between the reduction in PV component costs that have been occurring over the past twenty years, the lack of PV system price reductions through the first four years of the SGIP, and explore available pathways to address these apparent discrepancies.

2

Introduction

The California Self-Generation Incentive Program (SGIP) is a statewide[1] program developed by the California Public Utilities Commission (CPUC) to provide incentives for the installation of certain renewable and clean distributed generation technologies serving all or a portion of a facility's electric needs. This preliminary SGIP cost-effectiveness evaluation is the latest report in the ongoing assessment of the SGIP. Prior program evaluation activities addressed system performance characteristics (i.e., impact evaluation), and effectiveness of program implementation processes (i.e., process evaluation).

The first step of the preliminary cost-effectiveness evaluation was to develop a SGIP-specific analysis framework.[2] The framework outlines how the most important cost and benefit elements of the analysis will be treated. The framework proposes to assess program cost-effectiveness from the perspectives of three key stakeholders:

- Society;
- SGIP Participants, and
- Nonparticipants (or Ratepayers).

This report utilizes this analytic methodology to assess SGIP cost-effectiveness.

2.1 Background

Assembly Bill 970 (Ducheny, 2000), signed into law on September 6, 2000, required the CPUC to initiate certain load control and distributed generation program activities. The SGIP was adopted by the CPUC on March 21, 2001 under Decision D.01-03-073. Since July 2001, the SGIP has been available to provide financial incentives for installation of new qualifying electric generation equipment that can meet all or a portion of the electric needs of an eligible customer's facility. The SGIP is available to electric and/or gas customers of Southern California Edison, Pacific Gas and Electric, Southern California Gas Company, and

1 Available in the service territories of Pacific Gas & Electric, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric.

2 Itron, Inc., *Self-Generation Incentive Program: Framework for Assessing the Cost-Effectiveness of the Self-Generation Incentive Program*, prepared for the California Public Utilities Commission, March 2005.

San Diego Gas and Electric. The SGIP was authorized an annual statewide allocation of $125 million for program years 2001 through 2004. Assembly Bill 1685, signed into effect on October 12, 2003, extended the SGIP through December 31, 2007. The SGIP was designed utilizing information available in 2001 regarding likely distributed generation (DG) costs and expected benefits. Since then, cost and operational data collected from SGIP projects in real-time provide an opportunity to assess actual program costs and benefits, and to recommend refinements to program design and evaluation techniques.

The cost-effectiveness framework developed by Itron is the result of a number of CPUC decisions, rulings, and hearings. In Decision 01-03-073, the CPUC directed the Energy Division to retain a consultant to study and develop recommendations concerning cost-effectiveness assumptions used to evaluate energy efficiency, demand response, or distributed generation projects and programs. A subsequent decision, D.03-04-055, refined the scope of work to update the avoided costs and externality adders presently used to evaluate energy efficiency programs. These avoided costs and externality adders constitute some, but not all, of the required inputs to the Standard Practice Manual[3] (SPM) cost-effectiveness tests. Energy and Environmental Economics, Inc. (E^3) prepared and submitted a report to the CPUC in January 2004 addressing avoided costs and externality adders. The E^3 report was finalized on October 25, 2004. In R.04-03-017, the CPUC expressed its intention to develop an overall DG cost-benefit methodology. The CPUC directed that such an approach would, to the extent possible, consider other cost-effectiveness tests, such as those described in the E^3 report, the SPM, and input assumptions from the E^3 report. In addition, the August 6, 2004 Assigned Commissioner's Scoping Memo directed parties to propose cost-benefit methodologies in testimony due in October 2004.

The SGIP-specific cost-effectiveness framework developed by Itron is based largely on the SPM, the E^3 report approach, E^3 findings relative to avoided costs and externalities, and testimony provided by parties relative to distributed generation cost-effectiveness evaluation. Itron made this framework publicly available in March 2005. The framework was distributed to the interested parties for comment.[4]

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[3] *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, Governor's Office of Planning and Research, July 2002.

[4] On September 6, 2005, the CPUC issued interim ruling R.04-03-017. Both the framework and the treatment of costs and benefits within this evaluation are consistent with the adopted policies and principles with few exceptions.

2.2 Purpose

This report provides the first cost-effectiveness assessment of the SGIP. The findings in this report are intended to:

- Establish an updated cost-effectiveness reference point based on information that was not available at the time the SGIP was originally conceived and designed (e.g., updated forecasts of avoided costs and retail electricity rates, actual self-generation system installed and operating costs),
- Assess the influence of certain parameters (e.g., self-generation system capacity factor) on the estimate of program cost-effectiveness; and
- Illuminate the economic market drivers of DG from the perspective of SGIP participants.

2.3 General Approach

The March 2005 framework report served as the overall guide for this Preliminary Cost-Effectiveness Evaluation analysis. Due to the preliminary nature of this analysis, its scope is largely focused on assessment of solar photovoltaic (PV) systems and cogeneration systems fueled by natural gas. These technologies account for 95% of the operational SGIP system capacity as of the end of 2004, and 98% of the incentives (distributed or reserved) corresponding to these projects. Information for biogas-fueled systems has been included, but is limited to a relatively small number of systems.

The principal data elements identified in the framework are summarized briefly below. Detailed discussion of these data elements and their use in the preliminary cost-effectiveness analysis is included in subsequent sections of this report.

SGIP System Data

Data obtained through program applications and site inspections include system type, system size, technology type, fuel type, eligible system installed cost, SGIP incentive magnitude, and startup date.

Avoided Cost Data

When program participants generate their own power, their utility companies avoid costs that would otherwise have been incurred to procure and deliver that electric power using conventional means. The avoided electric cost values for each electric utility vary from hour to hour during the year and are a function of many factors. Substitution of self-generation in place of conventional central station generation technologies also results in changes in air pollutant emission rates, which may have economic consequences. Avoided electric and environmental cost forecasts and associated models developed by E^3 [5] and approved by the CPUC in D.05-04-024 are used to calculate avoided electricity generation benefits and avoided external environmental benefits in this assessment for the Nonparticipant and Societal tests.

Metered Performance Data

The principal source of information on the performance of the DG systems subsidized by the SGIP is the data archive compiled by Itron in conjunction with its on-going SGIP monitoring program and data collection for the recently filed Fourth-Year Program Impact Report. Metered data for a sample of operational projects were available. The metered data include electric net generator output, fuel consumption, and useful recovered thermal energy (heat). In some instances (e.g., electricity and heat), data are provided on an hourly basis throughout the year. Fuel data are more typically collected on a monthly basis.

Utility Tariff Data

Forecasts of retail prices for both gas and electricity rely on current tariffs as a starting point. Retail electric prices were escalated based on revenue requirement forecasts developed by the utilities. Retail gas rates were used to value both purchased generator input fuel and avoided purchases of natural gas resulting from recovered waste heat.

Data from Secondary Sources

While key DG system-eligible initial costs and first-year performance information is available at the site-specific level, the life-cycle basis of this analysis requires incorporation of additional cost and performance data from secondary sources. For example, cogeneration system prime movers require a major overhaul periodically, and some PV power inverters may require replacement while PV module power output is expected to degrade slowly. Values assumed for these types of data elements are based on secondary sources.

Other Assumptions

Influential assumptions are embedded in many of the data elements identified above. Other assumptions having a direct bearing on the cost-effectiveness evaluation results include those related to such factors as inflation rates, debt service (loan) interest rates, private and social discount rates, and treatment of tax rates, credits, and depreciation.

[5] Energy and Environmental Economics, Inc., *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, prepared for the California Public Utilities Commission, October 25, 2004. Available at www.ethree.com/cpuc_avoidedcosts.html.

2.4 Variation from the Standard Practice Manual

The Standard Practice Manual was originally developed in February of 1983 to provide official guidelines for evaluating the cost-effectiveness of conservation and load management programs from a variety of perspectives. Perspectives in the 1983 SPM included participants, nonparticipants, all ratepayers, society, and the utility. The SPM was revised in 1987-88. Primary changes between the 1983 and 1987 SPM included: renaming of the "Nonparticipant" Test to the "Ratepayer Impact Test (RIM)," renaming of the "All Ratepayer" Test to the "Total Resource Cost (TRC)" Test, and treatment of the "Societal" Test as a variant of the TRC. The SPM was again revised in 2001 to reflect cumulative changes in the natural gas and electric industries. Among the changes made in the 2001 SPM include renaming of the "Utility" Test to the "Program Administrator" Test, definition of self-generation as a type of demand-side management, and expanded description of externalities in the Societal Test. In developing an SGIP-specific framework, Itron started with the concepts in the 2001 SPM and tailored them to the specific needs and aspects of self-generation technologies and systems. In general, this involved identifying the specific benefits and costs to be incorporated into each of the tests in order to apply them to self-generation. Itron considered a broad range of sources in developing the SGIP-specific framework including:

- Economic studies of distributed energy resources, with specific emphasis on the assessment of distributed generation options, the SPM, and cost-benefit analysis
- Public comments to the CPUC and the California Energy Commission on the assessment of DG technologies and market development programs
- The E^3 avoided cost study

As a result of this approach, the SGIP-specific framework differs from the SPM in containing more detail than the tests in the SPM and in being tailored to the needs of evaluating distributed generation programs. An overview of each test, a description of the cost and benefit components used in the test, and how it differs from the SPM is contained in each of the following sections. Appendix D provides a listing of framework equations used for each test. Appendix E provides a listing of the cost and benefit components used by Itron for each SGIP technology under each of the test perspectives.

2.5 Report Organization

An Executive Summary, which provides a high-level overview of the key objectives and findings of this preliminary cost-effectiveness evaluation, is presented in Section 1 of this report. The remainder of the report has been organized as described below:

- **Section 3** describes the data and assumptions used to estimate the effects of the SGIP on the component variables used in the three test perspectives.
- **Section 4** presents the cost-effectiveness results with respect to the Societal Test.
- **Section 5** presents the cost-effectiveness results with respect to the Participant Test.
- **Section 6** presents the cost-effectiveness results with respect to the Nonparticipant Test.
- **Appendix A** contains additional detail regarding the modeling of PV, biogas, and cogeneration system performance for the "typical meteorological year".
- **Appendix B** contains details of the utility avoided cost forecasts.
- **Appendix C** contains detailed retail energy price forecasts.
- **Appendix D** contains details of the framework methodology.
- **Appendix E** contains detailed results for individual benefit and cost elements.
- **Appendix F** presents the cost-effectiveness results with respect to the Total Resource Cost Test.

3

Cost and Benefit Components

This section describes how the components used to evaluate SGIP cost-effectiveness are calculated. Program cost-effectiveness is evaluated from three perspectives. Many components of the economic cost and benefit analyses are common to more than one perspective. Thus, to avoid repetition, the component cost-benefit data, methods, and assumptions are described in this section. The applicability of these cost-benefit components is explained in Sections 4 to 6, in which the costs and benefits are summarized for each of the three primary perspectives (society, SGIP participants and nonparticipants). Appendix F contains an explanation of a fourth test; the Total Resource Cost (TRC) Test.[1] .

The discussion of the cost-benefit components is organized as follows:

- Equipment Purchase and Maintenance
- Electricity Production and Savings
- Natural Gas Consumption and Savings
- SGIP Administration and Incentives
- General Financial Assumptions

3.1 Equipment Purchase and Maintenance

Equipment Purchase

SGIP project costs are provided by program applicants through the program application process. This project cost information is available in aggregate in Itron's 2004 Program Impact Report.[2] These costs include the cost of generation equipment and pollution control equipment (where applicable). Reported SGIP DG system costs are summarized by technology type in Table 3-1. These totals include the costs for design, installation, and manufacturers' warranty in addition to hardware costs. Note that capital costs for SGIP systems may reflect the effect of incentive levels.

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[1] The TRC Test looks at the combined participants plus nonparticipants perspective.

[2] Itron, Inc., *CPUC Self-Generation Incentive Program Fourth-Year Impact Report,* prepared for Southern California Edison and the Self Generation Incentive Program Working Group, April 15, 2005

Table 3-1: SGIP DG System Costs

Technology	SGIP DG System Cost Total (MW)	Avg. ($/W)	Total ($ MM)
PV	31.0	$8.30	$257.2
Biogas	3.2	$2.81	$9.1
Cogeneration	68.8	$2.07	$142.7
– Microturbine	6.4	$2.69	$17.1
– Engine	62.5	$2.01	$125.6
Total	**103.1**	**$3.97**	**$409.0**

The equipment purchase price data summarized in Table 3-1 are based on equipment and systems eligible for SGIP incentives. In developing the SGIP-specific framework, Itron used a net-to-gross ratio for allocating costs and benefits attributable to the program. The net-to-gross ration represents the percentage of distributed generation technology that would not have been installed in the absence of the program. Itron assumed that for PV and cogeneration systems, 100% of the benefits can be attributed to the program. In some instances, distributed generation technology components were purchased and installed by project applicants even though the components were not eligible for SGIP incentives. Examples include new waste heat recovery absorption/adsorption chillers; battery backup with DC connection for some PV systems; and improved reactors for biogas systems. There are a significantly large number of new waste heat recovery chiller systems being installed, and relatively few installations of PV systems with battery backup and biogas systems with improved biogas reactors within the program. As a result, Itron made a simplifying assumption to consider only the additional costs and benefits associated with waste heat recovery chillers in the evaluation of SGIP cost-effectiveness. The net impact of this assumption was an improvement in cost-effectiveness of those cogeneration systems employing new waste heat recovery chillers.

The benefits of the newly installed heat recovery chillers were estimated based on the assumption that they were installed in lieu of new standard-efficiency electric chillers. Substitution of heat recovery chiller capacity for electric chiller capacity yields electricity savings that are discussed in a later section of this chapter. These electricity savings correspond to a cost adder for the heat recovery chiller. Chiller purchase price estimates obtained from independent sources are summarized in Table 3-2. The additional cost adder of new heat recovery chillers installed in lieu of new electric chillers is estimated equal to $350 per Ton of chilling[3].

[3] 1 ton of chilling is equivalent to 12,000 Btu per hour of cooling

Table 3-2: New Chiller Costs

Technology	Assumed Cost ($/Ton)
Electric chiller	$350
Heat recovery chiller	$700

Equipment Maintenance

DG systems must be maintained if they are to continue operating reliably and efficiently throughout their life. Maintenance activities generally are of either the variable or the fixed variety. Examples of variable maintenance include engine tune-up and PV module washing. Fixed maintenance items, such as PV system inverter replacement and microturbine prime mover replacement, occur much less frequently but may involve considerable expense. Estimates of variable maintenance costs used in the preliminary cost-effectiveness evaluation analysis are summarized in Table 3-3.

The Base Case variable maintenance costs were developed from interviews with SGIP participants. Some owners of PV systems did not wash their PV modules, some utilized their own staff to wash PV modules periodically, and some hired outside firms to periodically wash the PV modules. The value indicated for PV module washing costs represents a weighted average based on the interviews.

In the case of engines and microturbines the interview respondents reported the expectation that maintenance costs would be lower in the future. To help gauge the influence of uncertainty on estimates of SGIP cost-effectiveness, information from secondary sources was used to estimate Optimistic Case variable maintenance costs for microturbines and engines.[4] In the case of engines, scheduled overhauls are included in the variable maintenance cost.

Table 3-3: Variable Maintenance Costs (Cents/kWh)

Technology	Base Case	Optimistic Case
PV	0.4	0.2
Microturbine	2.6	0.6
Engine	2.0	1.0

Assumed fixed maintenance events and estimated costs are presented in Table 3-4. All of the SGIP systems are assumed to have economic lives of 20 years. In the case of PV, inverters are assumed to require replacement half way through their economic life. The equipment life

[4] Gas-Fired Distributed Energy Resource Technology Characterizations, joint project of the Gas Research Institute (GRI) and the National Renewable Energy Laboratory (NREL), October 2003.

assumed for microturbines is 10 years, which explains the replacement event occurring half way through the cogeneration system economic life.

Table 3-4: Fixed Maintenance Costs

Technology	Maintenance Event	Frequency	Cost (% of Initial DG System Cost)	
			Base	Optimistic
PV	Inverter replacement	10 years	20%	10%
Microturbine	Microturbine replacement	10 years	60%	30%

Equipment Salvage Value

While the economic life of SGIP PV systems is assumed to be 20 years, the PV modules are assumed to retain some economic value at the end of the system economic life. In the preliminary cost-effectiveness evaluation the salvage value of PV modules is assumed equal to 10% (in real terms) of the initial PV system cost.

3.2 Electricity Production and Savings

All SGIP DG systems produce electricity for use by the host facility. In some cases the waste heat from cogeneration systems is used to substitute for site energy needs that would otherwise be met using electricity. Electrical usage displaced in this manner is valued at the retail price or the avoided cost of electricity, depending on the test perspective. Valuation of electricity production and savings (i.e., displacement) entails two steps. First, available metered data are used to estimate electricity production and savings (kWh) for each hour of a typical meteorological year (TMY). Next, information about retail prices and utility avoided costs is used to calculate estimates of the economic value corresponding to the hourly kWh values.

TMY 8760-Hour Electricity Production and Savings (kWh)

Available metered data are used to estimate electricity production and savings (kWh) for each hour of a typical meteorological year (TMY). These TMY data sets were produced for each year of each SGIP system's economic life. Use of metered data to develop TMY data sets for PV systems and cogeneration systems is summarized below.

PV Systems

The power output of PV systems depends on the weather. Weather occurring during any particular period of time may deviate from the long-run average (i.e., climate). To ensure that PV system performance information included in the lifecycle cost-effectiveness analysis is representative of climate the available metered power output data collected from SGIP PV systems were adjusted using TMY data. This weather normalization adjustment process also yielded PV system performance information that was used to estimate power output of SGIP PV systems for which no metered power output data were available. The analysis accounted for effects of PV system orientation, location, and size. Details of the PV system power output analytic methodology are contained in Appendix A.

Cogeneration and Biogas Systems

The power output of cogeneration and biogas systems depends on many factors. To ensure that power output performance information included in the lifecycle cost-effectiveness analysis is representative of long-run average performance expectations it was necessary to adjust the available metered data collected from SGIP systems. The adjustments accounted for two factors. The first factor adjusts capacity factor due to the uncommonly high natural gas prices occurring during the fourth quarter of 2004.[5] This capacity factor adjustment was applied only to natural gas cogeneration systems, and is described in Appendix A (see page A-3). The second factor adjusts for the likelihood that system performance will improve as owners and vendors gain operating experience. This adjustment applies both to natural gas cogeneration systems and biogas systems.[6] The net impact of these adjustments was an improvement in cogeneration and biogas system cost-effectiveness.

The fairly short observation period provides a less than ideal basis for projecting power output performance of monitored systems 20 years into the future. Projected performance of the unmonitored systems is subject to even greater uncertainty. Simply projecting the first year capacity factors into the future may underestimate lifecycle averages because system commissioning and optimization may take a year or longer. To help gauge the influence of uncertainty on estimates of SGIP cost-effectiveness an alternative set of cogeneration system performance data was developed from the available metered data.

For each system the three months exhibiting the best performance were identified and used to calculate average capacity factors and heat recovery rates that were subsequently assumed for all other months. Weighted average results are summarized in Table 3-5.

[5] Due to high natural gas prices, a number of SGIP cogeneration facilities would not operate their systems during non-peak conditions or when they could not use the electricity on-site. As such, this reduced the capacity factor below the technical rating.

[6] Capacity factors for natural gas cogeneration and biogas systems employed in the SGIP are significantly below the 70% plus capacity factors typically observed for these technologies. Interviews with SGIP applicants indicated that lack of experience with microturbine and biogas engine technologies resulted to some degree of reduced capacity factor. As a result, a capacity factor adjustment took this learning curve into account. This adjustment was not made to PV or wind systems as the intermittent nature of the resource was believed to have a substantially greater impact on capacity factor.

Table 3-5: Cogeneration and Biogas System Capacity Factor Scenarios

Technology Type	Base Case	Optimistic Case
Biogas	40%	43%
Natural Gas Microturbine	53%	55%
Natural Gas Engine	47%	49%

Details of the cogeneration and biogas system power output modeling methodology are contained in Appendix A.

Electricity Retail Value

The retail value of the electricity generated by SGIP-sponsored facilities is the product of the amount of generation produced by program-supported facilities and the unit-value of that generation. Despite the relatively short duration of data collection (usually less than one year), the electric net generator output (ENGO) data for the sampled projects contain sufficient detail to permit accurate evaluation of the retail value of the electricity based on time of day. This is important because the value of electricity is based not only on the quantity of energy but also the time period in which it is used.

Utility rate structures for medium to large commercial and industrial facility are based on the time period in which the usage occurs because it is more expensive to provide electricity during peak demand periods. Both the utility-billed energy charges (cost per kWh) and demand charges (cost per kW) are based on time of use. Electric tariffs used as the basis for this cost-effectiveness evaluation are listed in Table 3-6.[7]

Table 3-6: Electric Tariffs

Utility	Electric Tariff
PG&E	E-19: Medium General Demand-Metered Time-of-Use Service
SCE	TOU-8: Time-of-Use – General Service – Large
SDG&E	AL-TOU-DER: General Service – Time Metered – Distributed Energy Resources

Calculation of retail value of electricity generated by SGIP cogeneration systems includes effects of certain nonbypassable charges applied to departing loads. The Public Purpose Programs Charge (PPPC) and the Nuclear Decommissioning Charge (NDC) apply to all cogeneration systems; the DWR Bond Charge (DWR-BC) applies only to cogeneration

[7] These rates apply to facilities that have a demand of 500kW or more. Some of the SGIP sites have lower demand capacities. However, these three rates provide a reasonable first approximation. Retail electric rates for smaller capacity sites would be somewhat higher than the tariffs selected.

systems larger than 1 MW in size. To estimate the charges in future years these values were escalated using the assumed general rate of inflation.

Nonbypassable charges affecting cogeneration systems are presented in Table 3-7 in nominal dollars.

Table 3-7: Cogeneration System Nonbypassable Electric Charges (Cents/kWh)

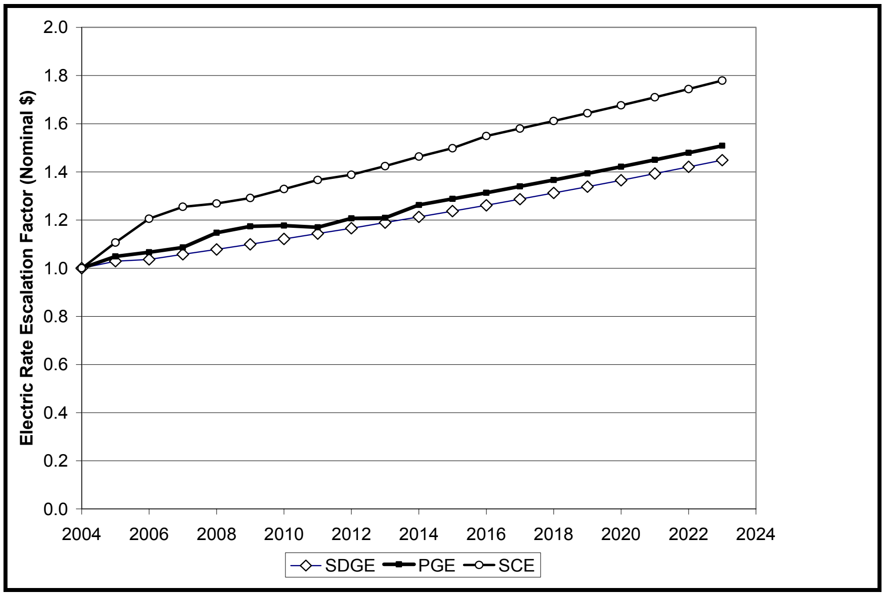
Electric Utility Tariff	Public Purpose Programs Charge (PPPC)	Nuclear Decommissioning Charge (NDC)	DWR Bond Charge* (DWR-BC)
PG&E E-19	0.472	0.035	0.459
SCG TOU-8	0.518	0.054	0.459
SDG&E AL-TOU-DER	0.576	0.056	0.459

*DWR-BC applies to systems larger than 1 MW.

Computing the retail value of energy saved by DG is straightforward using the ENGO data. Estimating the demand charge saving is more difficult without access to the revenue meter data for the entire site demand and without detailed knowledge of the planned facility operation. To get around this problem, it was assumed that the DG equipment would be used during the peak demand or partial peak demand periods. By identifying the monthly minima for these periods, the demand charges saving could be estimated.

The revenue requirement forecasts submitted by the electric utilities to the CEC in connection with the 2005 Integrated Energy Policy Report (IEPR) proceeding were used as the basis for projecting future retail electricity prices. The revenue requirement forecasts were transformed into escalation factors that were then applied to the January 2004 rates corresponding to the tariffs listed in Table 3-6. Because the utilities' revenue requirement forecasts only extend through 2016 the remaining years were assumed to have zero additional escalation in real terms. Results of the electric retail rate projection are depicted graphically in Figure 3-1. In real terms the rates of PG&E and SDG&E are projected to remain relatively unchanged through the study period, while those of SCE are expected to increase by approximately 20%. Electric rate escalation factors in Figure 3-1 are expressed in nominal dollars and therefore include effects of the 2% general inflation rate assumption. Details of the electric retail rate analysis are included as Appendix C.

Figure 3-1: Summary of Electric Retail Rate Projections



Electric Utility Avoided Costs

When DG systems produce electricity or yield electricity displacement the electric utility avoids having to provide power it would otherwise have had to deliver. The "avoided cost" of electricity refers to the value of this power. As with the retail value, avoided cost has both energy and a demand component. Both components are included in the E^3 Avoided Cost Model. The hourly avoided generation cost data were combined with estimated hourly generation profiles in the preliminary cost-effectiveness evaluation analysis.

The E^3 model computes avoided costs by year and hour of year for each of the three SGIP electric utilities. For each hour a marginal generator type and vintage is assumed based on load factors and on the mix of generation equipment likely to be used at that time. Off-peak hours are typically served by efficient, clean, base-loaded generation units. During peak hours less efficient and more polluting units are also brought into service.

The E^3 model includes both the energy costs and the T&D (transmission and distribution) costs for each hour for years 2006 through 2023. The T&D costs are used only for the hours when the utility is at or close to its peak capacity. As such, these costs are very sensitive to the time of generation and are highly variable.

Avoided Generation Costs

The E^3 avoided generation cost forecasts are used to value the energy benefits of SGIP systems. The avoided costs reflect the hourly marginal costs of utility generation. They thus also reflect the value to society and to utility ratepayers corresponding to reduced electricity demand resulting from operation of SGIP systems. In addition to cost elements such as fuel and pollution management costs[8], the energy component of avoided costs from E^3's model also includes several additional factors discussed in the Framework Report. These factors include: reliability net benefits, reduced line losses, and price effects. Each of these factors is discussed briefly below.

Reliability Net Benefits. In the E^3 model, reliability net benefits are defined as the cost of providing ancillary services for a given load. As noted in the Framework Report, these effects are reflected in E^3's Electricity Avoided Cost model as a 0.3 cents per kWh adder to the energy component of avoided costs. Thus they are included in the present analysis wherever avoided electricity costs are calculated. Reliability effects on the grid, as noted in the Framework report, are counted in a limited sense.

Reduced Line Losses. Line losses are eliminated for locally consumed on-site generation. This benefit of DG is accounted for in the E^3 generation avoided costs.

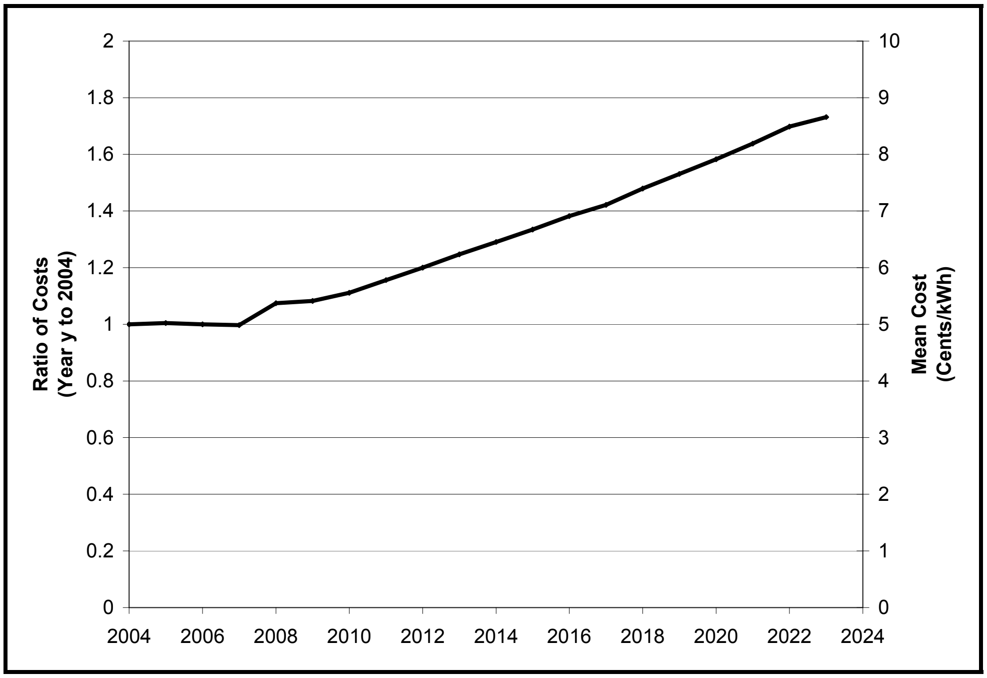
Price Effects. By reducing electricity demand for all ratepayers, it can be argued that the SGIP program produces positive price externalities by lowering the price elasticity for electricity. But as noted in Section 4.2.8 of the Framework Report this would only be true if the electricity system were not in long-run equilibrium. The E^3 analysis assumes that the system is in log-run equilibrium starting in 2008. Prior to that time, a small (0.3%) adder is included in avoided costs. After that time, the adder is zero. These effects were included in the framework's proposed analytic methodology and they are included in the preliminary cost-effectiveness evaluation analysis.

The electric energy avoided cost data are summarized at a very high level in Figure 3-2, which illustrates the trend for costs in a similar format as was used for electricity prices in Figure 3-1. The avoided cost data for each year shown in Figure 3-2 represent means of all of the hourly values for all climate zones, electric utilities, and zones. As such, they provide a very general indication of the projected trend for electric energy avoided costs. On the right-hand axis the mean avoided costs are expressed in units of cents/kWh (2004 \$). During the period 2004 through 2023 the per-kWh avoided costs are projected to increase by approximately 70%. The discrepancy between projected avoided costs and projected retail rates pinpoints a problem that surfaced in operation of natural gas-fired cogeneration facilities. In particular, volatility in natural gas prices is not realized in retail rates. Consequently, SGIP cogeneration facilities faced with unusually high natural gas prices in the fourth quarter of 2004 elected to shut down their facilities during non-peak hours as they

[8] Generation of electricity using conventional means results in creation of certain gaseous and particulate pollutants that must be managed. Principal means of management include ownership and operation of air pollution control systems, and purchase of air pollutant emissions offsets on the open market.

were unable to recoup the prices paid for natural gas in the lower electricity retail rate savings.

Figure 3-2: Summary of Electric Energy Avoided Cost Projections



Avoided Transmission and Distribution Costs

E^3 provides forecasts of avoided T&D costs by utility, climate zone, division, voltage level, hour, and forecast year. These costs are meant to be discounted savings from deferrals of T&D investments. Due to information availability constraints there is some question as to the applicability of the E^3 T&D avoided cost data to the evaluation of the SGIP.[9] In light of this the framework includes this parameter as a benefit of the program, but sets these benefits equal to zero for purposes of calculating primary estimates of SGIP cost-effectiveness. However, to provide potentially useful information to the regulatory process results are also calculated for a scenario that includes the E^3 T&D avoided costs in the estimation of T&D benefits.

Other Factors

Possible economic impacts (e.g., employment, income, tax revenues), national security impacts, and power quality impacts of DG were discussed in the Framework Report. However, these factors were not included in the framework's proposed analytic methodology and they are not included in the preliminary cost-effectiveness evaluation analysis.

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[9] Moreover, as D.01-03-073 precludes SGIP projects from entering into contracts for distribution services, Itron has assumed that these benefits are set to zero in the cost-effectiveness evaluation.

3.3 Natural Gas Consumption and Savings

The volume of natural gas affected by the program consists of both the fuel used for cogeneration and the volume of gas saved as a result of utilization of useful recovered heat. As with electricity, natural gas is valued both in terms of it retail value and the costs avoided/incurred by the gas utility or society as a consequence of changes in overall gas delivery. These cost elements are used in the cost-effectiveness tests as appropriate for each test perspective.

TMY 8760-Hour Natural Gas Consumption and Savings

Natural gas consumption of microturbines and engines is a function of power output and electrical conversion efficiency. Modeling of cogeneration system power output was discussed above in Section 3.2. In most cases where power output data were available metered natural gas consumption data collected by utility companies were also available. In cases where metered natural gas consumption data were not available the gas usage was estimated using typical electrical conversion rates indicated by the available metered data.

Estimates of natural gas savings resulting from utilization of recovered heat were calculated based on available metered heat recovery rates. The quantity of metered heat recovery data remains small however. In cases where metered heat recovery data were not available the heat recovery rate was estimated using typical heat recovery rates indicated by the available metered data. In most cases heat recovered from cogeneration systems reduced fuel consumption of natural gas boilers. An assumed boiler efficiency of 75% was assumed to translate heat recovery rates into natural gas savings estimates.

Natural Gas Avoided Costs

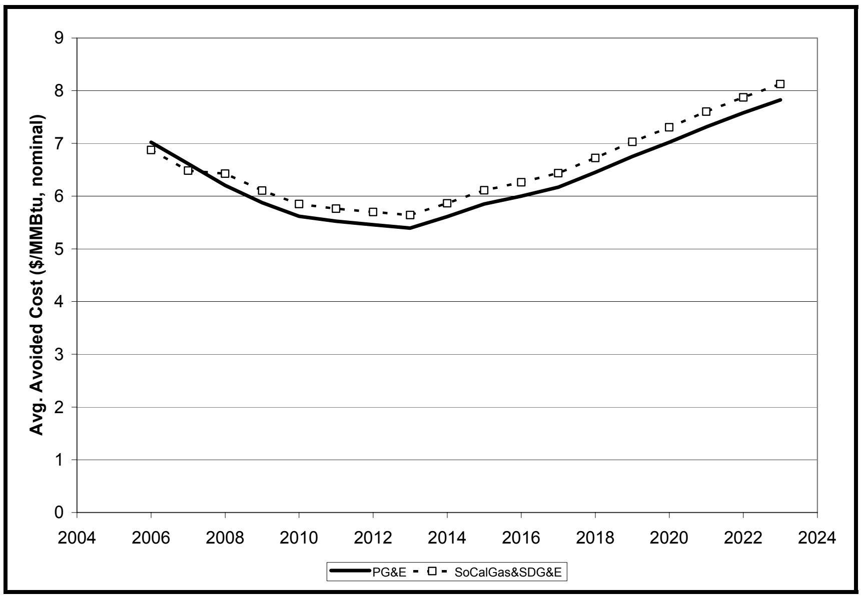
Total natural gas costs comprise a commodity component and a T&D component.[10] The basis of natural gas avoided costs depends on the test perspective. For this study all natural gas is assumed to be purchased under non-core tariffs. Under these tariffs the customer buys the commodity component of natural gas from some source other than the gas utility company. From the utility company's perspective, and thus from the perspective of its ratepayers, natural gas avoided costs are limited to the transportation component of natural gas costs. From society's perspective, natural gas avoided costs include both the commodity and transportation components.

[10] The workbook also treats an environmental component for NOx and CO2, however in our analysis we are treating this component outside of the E^3 workbook because we need to treat a variety of technologies not included among the end uses included in the E^3 workbook.

Estimated values of the transportation component of natural gas avoided costs are based on a simplifying assumption. Specifically, the costs faced by natural gas utility companies to transport fuel used in SGIP systems are assumed to be equal to the marginal costs faced by natural gas utility companies to transport fuel to their commercial core customers. Gas transportation marginal costs for commercial core customers were obtained from E^3. These costs are assumed to escalate at the general rate of inflation (2%).

The variability exhibited by total natural gas avoided cost values across years is summarized in Figure 3-3. Data currently available from E^3 extend from 2006 onward, whereas for purposes of this cost-effectiveness analysis 2004 is assumed to be the first year of SGIP system operation. In this analysis the nominal 2006 data were also used for 2004 and 2005.

Figure 3-3: Annual Average Natural Gas Avoided Cost from Society's Perspective by Year



Natural Gas Retail Value

Price forecasts for natural gas purchased by electricity generators are included in the E^3 electricity avoided cost model. These same price forecasts are applicable to SGIP cogeneration systems. Details of the application of the price forecasts are included as Appendix C.[11]

[11] In preparing this report, it became apparent that discrepancies between natural gas prices and retail rate electricity were negatively impacting natural gas-fired SGIP facilities. Differences between the magnitude of natural gas price forecasts and projected electricity retail rates suggest future discrepancies could occur with similar negative impacts. See Appendix A for additional discussion on the relationship between natural gas prices and the SGIP natural gas-fired cogeneration capacity factors.

3.4 SGIP Administration and Incentives

The program's implementation and evaluation costs are included in the cost-effectiveness analysis. Implementation costs comprise two components: incentives and administration. Incentives corresponding to the SGIP systems included in this preliminary cost-effectiveness evaluation are summarized in Table 3-8.

Table 3-8: Incentives Paid and Reserved

Technology	Incentives Paid/Reserved Total (MW)	Avg. ($/W)	Total ($ MM)
PV	29.6	$3.4	$101.2
Biogas	3.2	$0.78	$2.5
Cogeneration	42.2	$0.58	$24.6
– Microturbine	37.1	$0.56	$20.9
– Engine	5.1	$0.72	$3.7
Total	**71.8**	**$1.75**	**$125.8**

Expenditures for program administration cover such factors as salaries and facilities, and costs incurred by program administrators to hire subcontractors involved with program design and implementation (e.g., engineering firms performing field work and providing engineering review services). Program administrators report these costs to the CPUC on a regular basis. Through the end of 2004 the total of these costs for the four program administrators totaled $9.4 million.

Program evaluation costs include those incurred by program administrators individually to hire electric meter installation subcontractors, and those incurred jointly to cover the costs of the principal program evaluation subcontractor. Through the end of 2004 the total of these costs for the four program administrators totaled $3.1 million.

The simplest treatment of total program administration and evaluation costs ($12.5 million) would be to allocate the total across all active and complete projects based on project size. This approach results in an estimate of per-kW program administration cost equal to $47.75/kW. Cogeneration projects require engineering review of waste heat utilization worksheets, and the metering for cogeneration projects costs more than the metering for PV projects. On the other hand, the average size of PV projects (138 kW) is smaller than the average size of cogeneration projects (481 kW), and some costs (e.g., creating and maintaining files, driving to a site to verify system installation) are relatively independent of project size. Given these considerations, the possible benefits of more rigorous allocation analysis were deemed inconsequential and the $47.75/kW result was used in the analysis.

3.5 General Financial Assumptions

For simplicity several assumptions are made regarding the timing of the system installation and the financial arrangements. The systems are assumed to be paid for and installed in year zero. In year 1 the system is assumed to be fully operational and to receive the incentive payment. Federal and state tax credits are assumed to be received in year one.[12] For Participant Test purposes, after-tax costs and benefits are assumed to be the relevant measure. For this purpose it was assumed that the marginal tax rate for participant system owners is 34% federal and 8% state, for an effective marginal tax rate of 39.3%.

The assumption regarding general inflation rates, cost escalation rates, social and private discount rates and loan rates are all assumed to be interrelated. An inflation rate equal to 2% is assumed. Assuming this inflation and a real social discount rate of 3% yields a nominal social discount rate of 5.1%.[13] The real discount rate applicable to the other three perspectives is assumed to be 6% in real terms. Discount rates assumed for the analysis are summarized in Table 3-9.

Table 3-9: Discount Rates Assumed in the Analysis

Test	Discount Rate (%, nominal)
Societal Test	5.1%
Total Resource Cost Test	8.1%
Participant Test	8.1%
Nonparticipant Test	8.1%

The loan term for financed equipment is limited to the typical expected life of the generating source. The capital cost of equipment is assumed to be financed by a loan that covers the entire capital cost less incentive payments.

O&M costs for SGIP projects are assumed to escalate at the general inflation rate. It is assumed that the costs of major non-routine maintenance events (such as replacement of PV inverters after 10 years) are expensed[14] in the year they occur.

[12] In effect, the system owner carries the capital costs offset by the incentive and the tax credits during year zero.

[13] The nominal discount rate is calculated as (1+inflation rate) x (1+real discount rate) – 1.

[14] This implies that the equipment owner has sufficient profits to offset these expenses. If this were not the case, the deduction would be carried forward into future years.

4

Societal Test

4.1 Introduction

The societal test evaluates the costs and benefits of the SGIP from the perspective of all members of society. The reason for adopting a Societal perspective is that it is consistent with the Commission's desire to use this type of methodology to assess resource options, one of which (DG) is promoted through the SGIP. A distinguishing characteristic of the societal test is its inclusion of economic impacts of air pollutant emissions that are not tied directly to the delivery or purchase of energy. Environmental externalities covered by this analysis include oxides of nitrogen (NOx) and carbon dioxide (CO_2). The societal test also includes consideration of adders for reliability, marginal transmission and distribution effects and other social externalities. Section 4.2 discusses differences between the Standard Practice Manual and the SGIP-framework relative to the societal test. Section 4.3 discusses the components and methods used to evaluate societal benefits. Societal cost variables and measurement methods are presented in Section 4.4. The last section provides a summary of SGIP cost-effectiveness evaluation results from the perspective of all members of society.

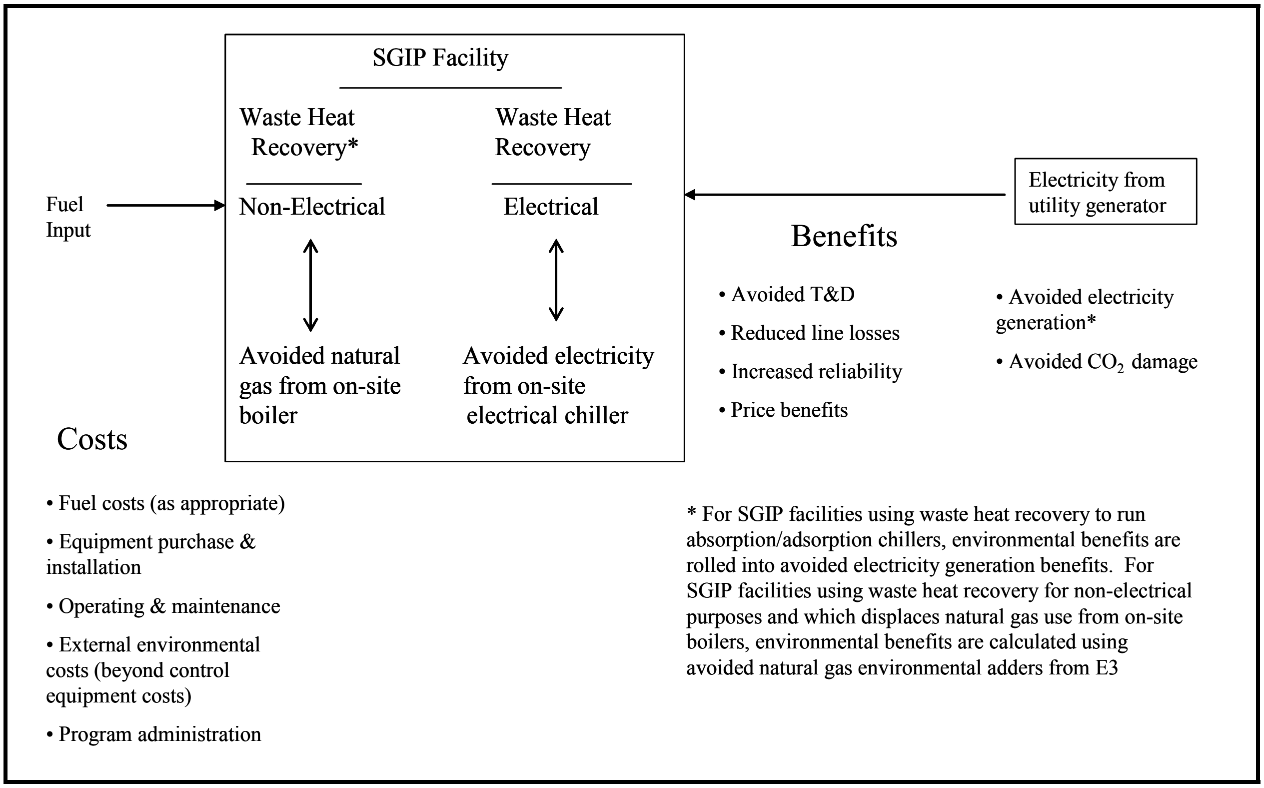
4.2 Variations from the SPM

The Itron framework report details the reasoning behind, and the development of, an SGIP-specific societal test, and contains more detailed discussion of the components. In general, the societal test is a variant of the CPUC's Total Resource Cost (TRC) Test. The perspective of the Societal Test differs from that of the standard TRC in three ways:

- The Societal Test ignores tax credits, which are benefits to participants but costs to other taxpayers,
- The Societal Test considers a series of "externalities," which affect society as a whole, and
- The Societal Test makes use of a societal discount rate, which is generally lower than the private discount rate employed in the TRC test.

Figure 4-1 shows the general relationship between benefits and costs for an SGIP cogeneration facility from the societal perspective.

Figure 4-1: Relationship Between Costs and Benefits in Societal Test



4.3 Societal Benefits

The benefit components included in the societal test are listed below. Several of these benefits also apply to one or more of the other tests. To avoid repetition in these cases discussion of the evaluation data, assumptions, and analysis pertaining to these common benefits is included in Section 3 of this report.

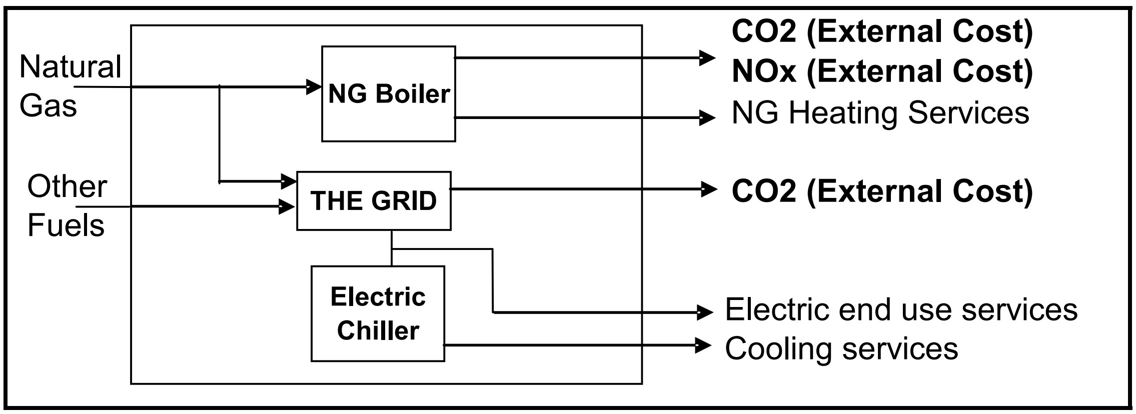
- Avoided generation costs (see Section 3.2)
- Avoided/deferred transmission and distribution capital costs (see Section 3.2)
- Reliability net benefits (see Section 3.2)
- Reduced line losses (see Section 3.2)
- External environmental benefits (see discussion below)
- Price effects (see Section 3.2)
- Waste heat use benefits of combined heat and power applications (see Section 3.3).

Only the external environmental benefits are discussed in detail in this section. Methods used to treat the remaining benefit categories were discussed previously and can be found in Section 3.2 and Section 3.3.

External Environmental Benefits

External environmental benefits refer to reductions in pollution-related costs that are excluded from transactions between utility companies and utility customers.[1] Operation of SGIP systems results in decreased use of conventional fuels and energy technologies to deliver heating, cooling, and electric end-use[2] energy services. These energy services, the conventional fuels and technologies, and resulting external environmental costs are depicted graphically in Figure 4-2 and Figure 4-3.[3] Avoidance of external environmental costs attributable to operation of SGIP systems represents an economic benefit from the perspective of society.

Figure 4-2: Summary of Energy Services and Avoided External Environmental Costs - Conventional Energy Services Delivery Model



Avoided External Environmental Costs – The Grid. All SGIP systems produce electricity that would otherwise have been provided by an electric utility company through the grid. When reliance on the grid is reduced, the air pollution emissions associated with grid generation are also reduced. To the extent that the reduced emissions are not internalized by the marketplace, these impacts should be valued and included in a societal test. This has been a fairly standard practice in California for the assessment of energy efficiency options. However, utility generation units are typically required to provide emission offsets for residual emissions of some pollutants. To the extent that the costs of generation reflect the costs of these offsets, these costs are internalized by the market and need not be considered separately as an additional benefit. Such offsets are currently required for NOx, and PM-10

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1 External costs stand in contrast to internal environmental costs that are accounted for in costs incurred by conventional generators and prices paid for grid-supplied power. Internal environmental costs are included in the market component of E^3s avoided electric cost model, as described in Section 3.2.

2 Including electric resistance heating applications.

3 PM-10 is not shown as an emission from natural gas boilers. The E^3 avoided cost model for natural gas consumption end uses excludes PM-10 as a significant pollutant because the levels of PM-10 emissions are so low that they would be inconsequential to the overall consumption emission analysis. PM-10 was treated identically in this cost-effectiveness analysis (including when the natural gas consumption end use was a microturbine or internal combustion engine).

emissions, but not for CO_2. As a result, the framework report specifies inclusion of environmental externalities for only emissions of carbon dioxide associated with grid generated electricity.

The E^3 model estimates the marginal economic impacts of carbon dioxide emissions. These estimates are used in the societal test cost-effectiveness evaluation to value CO_2 reduction benefits. The E^3 economic value of this environmental externality ranges from $8.00 per ton of reduced CO_2 in 2004 to $20 per ton of reduced CO_2 in 2023. As indicated in the E^3 report, the dollar per-MWH values for reduced CO_2 vary from hour to hour with changing characteristics of the marginal generation unit.[4]

Avoided External Environmental Costs – Natural Gas Boilers (at Host Sites). Many SGIP participants installing cogeneration systems use recovered heat to provide onsite heating services that would otherwise have been provided by a natural gas boiler. By utilizing waste heat the air pollution that would have been emitted by natural gas boilers is avoided. The societal costs associated with these emissions are not accounted for in the price of natural gas; they are external costs and therefore are accounted for separately in the cost-effectiveness evaluation. The E^3 avoided cost gas model is used to estimate the economic benefits from these avoided emissions. As with grid emissions, these estimates are based on avoided emission impacts that remain after required control devices were taken into account.

The E^3 model considered emissions from three size classes of natural gas boilers: residential units (generally less than 30,000 Btu per hour); small commercial boilers less than 100 million Btu per hour; and large industrial boilers greater than 100 million Btu per hour in rating. Using a heat rate of 14,000 Btu/kwhr for a typical SGIP generation unit provides an upper limit electricity generating capacity of 7 MW. As most SGIP facilities are sized below 7 MW, the cost effectiveness analysis used the values for small commercial natural gas fired boilers (<100 MMBtuh) with uncontrolled emissions out of the E^3 model. The CO_2 and NO_x emissions rates for such a boiler were estimated by E^3 in their Avoided Gas Cost Model[5], as were the avoided costs per unit of pollutant weight. The avoided environmental externalities resulting from decreased use of gas boilers are summarized in Table 4-1 on a per-million Btu (MMBtu) basis (higher heating value input). Note that for SGIP facilities that use waste heat recovery absorption/adsorption chillers, environmental benefits resulting from displaced electricity are captured in the avoided electricity generation calculations.

[4] For example,E^3 notes that CO_2 values ranged from approximately $3/MWhr to $8/MWhr depending on heat rate

[5] The E^3 avoided cost model for natural gas consumption end uses excludes PM-10 as a significant pollutant because the levels of PM-10 emissions are so low that they would be inconsequential to the overall consumption emission analysis. PM-10 was treated identically in this cost-effectiveness analysis (including when the natural gas consumption end use was a microturbine or internal combustion engine).

Table 4-1: Small Gas Boiler Environmental Externalities (2004[6])

Pollutant	Emission Rate (Pound/MMBtu)	Unit Value ($/lb)	Value ($/MMBtu)
NO_x	0.098	3.500	0.343
CO_2	117	0.004	0.468

Summary of Societal Benefits

The societal benefits of the program (*SocietalBenefits*) are specified as the sum of societal benefits associated with individual technologies ($SocietalBenefits_i$):

$$(1)\quad SocietalBenefits = \sum_{i=1}^{N} NTG_i \times (AvoidedElectricCosts_i + WasteHeatBenefits_i)$$

where $AvoidedElectricCosts_i$ represents avoided electric costs associated with technology *i*, $WasteHeatBenefits_i$ reflects total waste heat benefits associated with technology *i*, and NTG_i is a net-to-gross ratio assumed for the technology in question. This net-to-gross ratio reflects the fraction of benefits that are actually attributable to the program, and is defined as the percentage of distributed generation of the technology in question that would not have been installed in the absence of the SGIP. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for both PV and cogeneration systems.

4.4 Societal Costs

The cost components used in the societal test are listed below. Several of these costs also apply to one or more of the other tests. To avoid repetition in these cases discussion of the evaluation data, assumptions, and analysis pertaining to these common costs is included in Section 3 of this report.

- External environmental costs from cogeneration system operations (see discussion below).
- System purchase, operation, and maintenance costs (see Section 3.1)
- SGIP Program Administration costs (see Section 3.4)

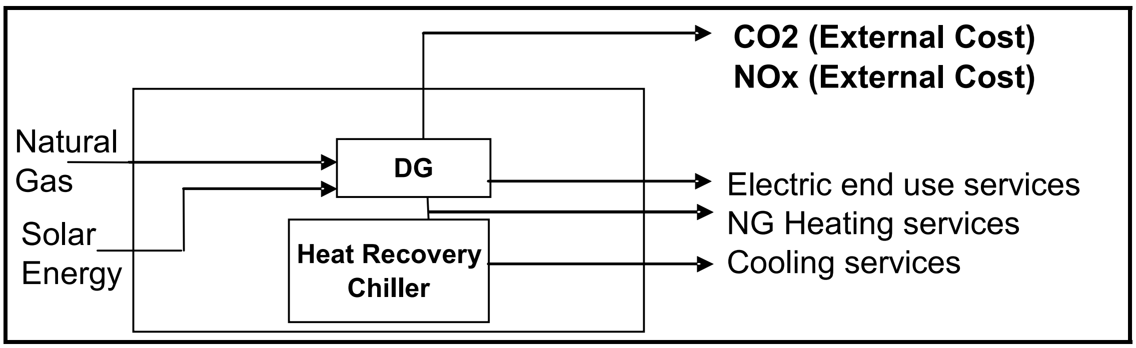
Only the external environmental costs are discussed in detail in this section. Methods used to treat the remaining cost categories were discussed previously and can be found in Section 3.1 and Section 3.4.

6 Table 4-1 presents avoided emissions values for 2004 only. These values, as estimated in the E^3 avoided cost gas model, increase over the period of analysis.

External Environmental Costs

Increased external environmental costs corresponding to operation of SGIP systems tends to offset the above-described benefits resulting from decreased reliance on the conventional energy services delivery model. These external environmental costs are depicted graphically in Figure 4-3.[7] The economic impacts of these emissions are not accounted for in the price of natural gas; they are external costs and therefore are accounted for separately in the cost-effectiveness evaluation for the societal perspective. Only SGIP systems that do not consume conventional fuels, such as PV or wind systems, do not incur these external environmental costs.

Figure 4-3: Summary of Energy Services and External Environmental Costs - DG Energy Services Delivery Model



Section 4.3 includes a discussion of the use of the E^3 Natural Gas Avoided Cost model to estimate the economic benefit attributable to reducing natural gas boiler use. A similar approach was used to estimate external environmental costs attributable to DG equipment operation.

The emission factors assumed for cogeneration systems are presented in Table 4-2. The emission rate values were obtained from manufacturers' specifications, California Air Resources Board distributed generation certification emissions standards (NOx), and a study of distributed generation completed by the National Renewable Energy Laboratory (CO_2).[8] Depending on the technology and the timing of delivery of energy services, cogeneration systems could create external environmental costs exceeding the air pollution control cost savings resulting from avoided grid generation.

7 This general model encompasses PV systems and cogeneration systems. When applied to PV systems, natural gas input is zero, air pollutant emissions are zero, and only electric end use services apply.

8 DER Benefits Studies: Final Report. National Renewable Energy Laboratory (NREL), June, 2003.

Table 4-2: Cogeneration System Environmental Externalities (2004)

Pollutant	Unit-Electricity Emission Rate (Pound/MWh) MT	ICE	Unit-Weight Value ($/lb)	Unit-Electricity Value ($/MWh) MT	ICE
NO_x	0.5	3	3.500	1.75	10.5
CO_2	1600	1300	0.004	6.4	5.2

The forecast values of the cost of air pollutants from the E^3 model were combined with estimates of DG air pollutant emissions characteristics to estimate the environmental cost incurred by society as a result of increased use of SGIP DG systems.

Summary of Societal Costs

In summary, societal costs include installed equipment costs (*InstCost*), operating and maintenance costs (*OMCost*), external environmental costs (*EnvCost*), and program administrative costs (*AdminCost*). The present value of societal costs is given by:

$$(2)\quad SocietalCosts = \sum_{i=1}^{N} NTG_i \times (InstCost_i + OMCost_i + EnvCost_i) + AdminCost_i$$

Note that costs associated with participant activity are multiplied by the net-to-gross ratio to account for the fact that some of these costs could have been incurred in the absence of the program. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for all projects. Program administrative costs are all attributable to the program and are thus not multiplied by *NTG*.

Both installation costs and program administration costs are assumed to be incurred in the year of the program; O&M costs and external environmental costs occur over the lifetime of the DG, and the societal discount rate is used to discount annual results back to present values.

4.5 Societal Test Results

Two figures of merit are used to summarize results of the societal test: net societal benefits and the benefit-cost ratio. The net societal benefits of the SGIP are calculated as the difference between societal benefits and societal costs:

$$(12)\quad Net\ Societal\ Benefits = SocietalBenefits - SocietalCosts$$

As indicated in Section 1, both a Base Case and Optimistic Case were developed for each of the tests. The Optimistic Case includes T&D benefits as well as other favorable assumptions about system performance and maintenance costs. Societal Test net benefits results of the cost-effectiveness evaluation for the Base Case are presented in Table 4-3. These results are based upon the available information from the operational projects under the SGIP as of December 31, 2004. This is the same reference point used for the program's PY2004 Impact Evaluation Report.

Table 4-3: Societal Test – Base Case Net Benefits Results Summary (Net present value, millions 2004 $)

Technology	NPV Benefits ($million)		NPV Costs ($million)	Net NPV Benefits ($million)	
	No T&D	T&D		No T&D	T&D
PV	$62	$75	$227	($165)	($152)
Biogas	$11	$11	$14	($4)	($3)
Cogeneration (all)	$402	$431	$558	($156)	($127)
IC Engine	$362	$389	$485	($123)	($96)
Microturbine	$40	$42	$73	($33)	($31)
Total	**$475**	**$517**	**$800**	**($325)**	**($283)**

A breakdown of Base Case net present value benefits is presented in Table 4-4.

Table 4-4: Societal Test – Breakdown of Base Case Benefits (Net present value, millions 2004 $)

Element	PV	Biogas	ICN	MTN
Avoided Electricity Costs	$46	$7	$269	$27
Avoided T&D Costs	$12	$1	$27	$2
Avoided Electricity CO2 Costs	$5	$1	$28	$3
Waste Heat Benefits NOx	$0	$0	$0	$0
Waste Heat Benefits CO2	$0	$0	$6	$1
Avoided (Host Site) Fuel Costs	$0	$3	$59	$9
Salvage Value of Equipment	$11	$0	$0	$0
Total (Excl. T&D)	**$62**	**$11**	**$362**	**$40**
Total (Incl. T&D)	**$75**	**$11**	**$389**	**$42**

A breakdown of Base Case net present value costs is presented in Table 4-5. Fuel costs for PV are zero, and initial system costs account for 86% of total costs. The periodic maintenance cost represents replacement of inverters mid-way through the life of the system. For the cogeneration technologies initial system costs account for less than 30% of total costs, while fuel is the largest cost element.

Table 4-5: Societal Test – Breakdown of Base Case NPV Costs (millions 2004 $)

Element	PV	Biogas	ICN	MTN
System costs	$195	$9	$119	$15
Maintenance Costs - Annual	$2	$4	$73	$11
Maintenance Costs - Periodic	$29	$2	$0	$7
DG NOx Costs	$0	$0	$0	$0
DG CO2 Costs	$0	$0	$24	$3
DG Fuel Costs	$0	$0	$267	$37
Program Administration	$1	$0	$3	$0
Total	**$227**	**$14**	**$485**	**$73**

The influence of T&D benefits on societal test results is indicated in Table 4-3 and Table 4-4. Including T&D benefits increases total net present value benefits of the evaluated group of projects by a total of 9% ($36 million). The influence of several other key factors was examined by calculating societal test results for an alternative, optimistic case.

Characteristics differentiating the base and optimistic cases are presented in Table 4-6.

Table 4-6: Comparison of Base and Optimistic Cases[9]

Technology	Factor	Base Case	Optimistic Case
PV	Annual O&M (Cents/kWh)	0.4	0.2
	Periodic O&M (% of System Cost)	20%	10%
Biogas	Annual O&M (Cents/kWh)	3.1	1.5
	Capacity Factor (%, Weighted Avg.)	40%	43%
ICN	Annual O&M (Cents/kWh)	2.0	1.0
	Capacity Factor (%, Weighted Avg.)	47%	49%
MTN	Annual O&M (Cents/kWh)	2.6	0.6
	Periodic O&M (% of System Cost)	60%	30%
	Capacity Factor (%, Weighted Avg.)	47%	55%
Cogeneration Heat Recovery	Heat Recovery Rate (MBtu/kWh, Avg.)	3.3	5.0

[9] Capacity factors are not provided for PV in table 4-5 as there was no change assumed for PV capacity factor between the base and optimistic case.

Societal Test net benefits results of the cost-effectiveness evaluation for the Optimistic Case are presented in Table 4-7. For cogeneration systems the higher capacity factors increase costs for fuel purchases as well as benefits (e.g., electric energy production).

Table 4-7: Societal Test - Benefits Results (Optimistic Case)

	NPV Benefits ($million)		NPV Costs	Net NPV Benefits ($million)	
Technology	**No T&D**	**T&D**	**($million)**	**No T&D**	**T&D**
PV	$62	$75	$222	($159)	($147)
Biogas	$13	$14	$12	$1	$2
Cogeneration (all)	$471	$502	$538	($67)	($36)
IC Engine	$424	$453	$474	($50)	($21)
Microturbine	$47	$50	$64	($17)	($15)
Total	**$547**	**$591**	**$771**	**($225)**	**($180)**

The societal benefit-cost ratio is calculated as:

(3) $$\text{Societal Benefit-Cost Ratio} = \frac{SocietalBenefits}{SocietalCosts}$$

Benefit-cost ratio results of the cost-effectiveness evaluation from the perspective of society are presented in Table 4-8. For all cogeneration systems, when excluding T&D benefits the optimistic cost and performance assumptions result in an 18% increase in benefit-cost ratio. The addition of T&D benefits increases the benefit-cost ratio result of PV by 25% and of cogeneration by 5%. The difference is attributable to the fact that PV system energy production occurs exclusively during daylight hours when T&D benefits occur.

Table 4-8: Societal Test – Benefit-Cost Ratio Results

	Base Case		Optimistic Case	
Technology	**No T&D**	**T&D**	**No T&D**	**T&D**
PV	0.27	0.33	0.28	0.34
Biogas	0.74	0.78	1.12	1.18
Cogeneration (all)	0.72	0.77	0.88	0.93
IC Engine	0.75	0.80	0.90	0.96
Microturbine	0.54	0.58	0.73	0.77
Total (Wtd. Avg.)	**0.59**	**0.65**	**0.71**	**0.77**

Additional discussion of the cost and benefit components, their overall impact on net present value of benefits, and the benefit-cost ratios is contained in Appendix E.

5

Participant Test

5.1 Introduction

The participant test evaluates the benefits and costs of the SGIP from the perspective of participants. From this perspective, the participant's costs of owning and operating the SGIP system are compared against the retail energy costs that would have been incurred by the participant had they continued to obtain all of their electricity from a utility company. A distinguishing characteristic of the participant test is its inclusion of the tax credit and depreciation effects.

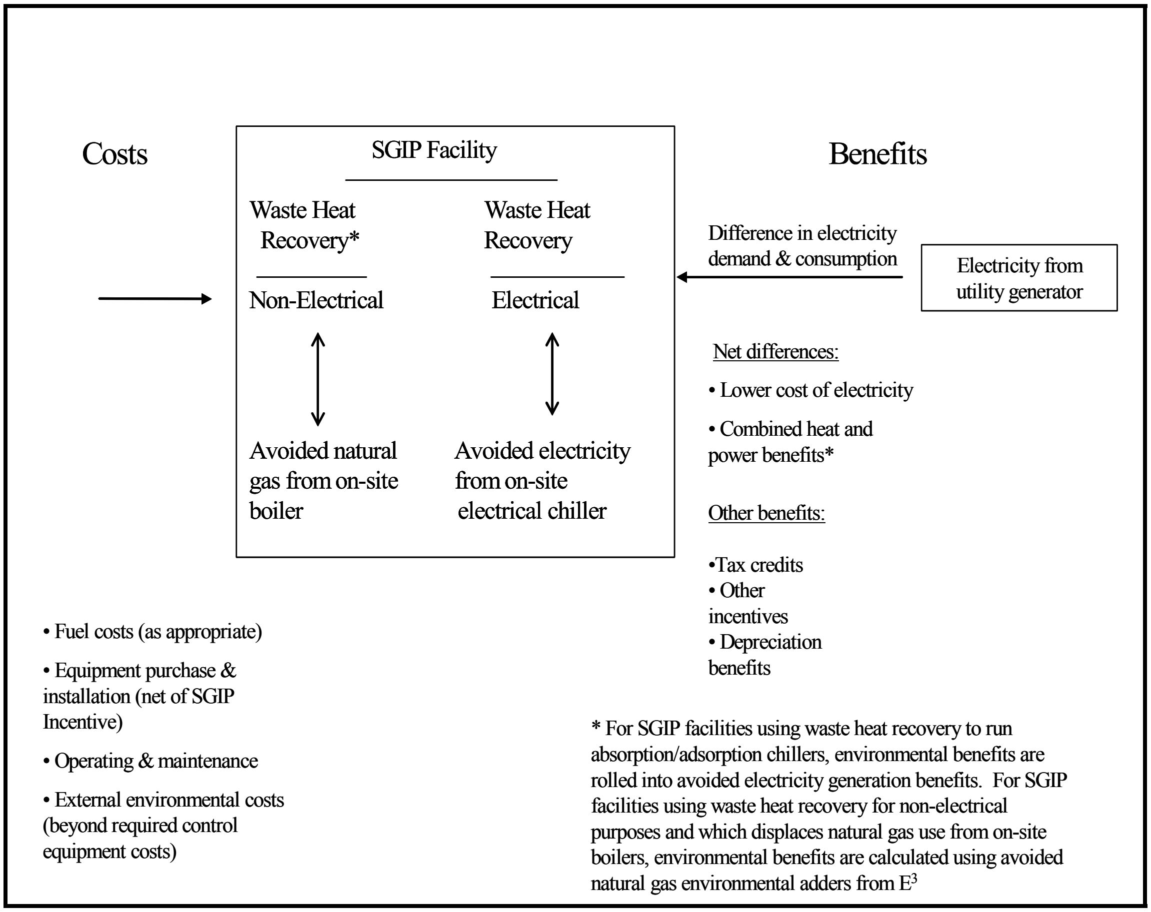
In this section, discussions of participant-perspective benefits and costs are followed by a summary of analytic methodologies pertaining specifically to the participant test. This section concludes with a summary of cost-effectiveness evaluation results from the perspective of specific groups of SGIP participants and all program participants.

5.2 Variations from the SPM

There are no discernable differences from the framework approach to the participant test and that used in the SPM. Within the SPM, the participant test is the measure of the quantifiable benefits and costs to the customer due to participation in the program. Benefits in the SPM and the framework participant test both include reduction in the customer's utility bill, any incentive paid by the utility or third party, and any received federal, state or local tax credits. Similarly, costs in the SPM and framework participant test include all out-of-pocket expenses incurred as a result of participating in the program, plus any increases in the customer's utility bill. These costs include the cost of any equipment or materials purchased, including sales tax and installation; any on-going operation and maintenance costs; any removal costs (minus the salvage value of the equipment); and the value of the customer's time in implementation of the system.

Figure 5-1 shows the general relationship between benefits and costs for an SGIP cogeneration facility from the participant perspective.

Figure 5-1: Relationship Between Participant Test Benefits and Costs



5.3 Participant Benefits

The benefits included in the Participant Test are listed below. In many cases these benefits also apply to one or more of the other tests as well. In these instances the discussion of the evaluation data, assumptions, and analysis is included in Section 3 of this report. To avoid repetition these discussions are not repeated here.

- Lower cost of electricity (*see Section 3.2*)
- Combined heat and power (*see Section 3.3*)
- Other incentives (*see discussion below*)
- Tax credits (*see discussion below*)
- Depreciation benefits (*see discussion below*)

Other incentives, tax credits, and depreciation benefits are discussed in detail in this section, because these benefits are applicable only to the Participant Test. Treatment of the remaining benefit categories is discussed in Section 3.2 and Section 3.3.

Tax Credits

State and federal tax regulations include provisions for tax credits and production incentives to offset the cost of qualifying SGIP systems. Tax credits affect project economics in a manner similar to that exhibited by the SGIP rebates. Tax credits are calculated as a percentage of system cost, and the system owner is able to reduce its tax liability by an amount equal to the tax credit. Tax credits were examined only for PV system projects.[1]

Key elements of tax credit regulations include provisions governing rates and bases. Key elements of applicable state tax credit regulations are summarized in Table 5-1.[2] The state tax credit rate depends on the tax year. For purposes of estimating SGIP cost-effectiveness, the date when the PV system entered normal operations was used as the basis for assigning a tax year.

Table 5-1: State Tax Credit Provisions – PV

Element	Description
Rate (%)	■ Varies depending on tax year: a) 2001-2003: 15.0% b) 2003-2005: 7.5%
Basis ($)	■ Applies only to first 200 kW of PV system capacity ■ Tax credit rate is applied to the *lesser* of a) $4.50/Watt, or b) Cost of system after deducting value of municipal, state (e.g., SGIP), or federal incentives

Key elements of applicable federal tax credit regulations are summarized in Table 5-2. [3] The federal tax credit is not subject to a maximum PV system size limit. Another possible federal tax credit is the recently enacted Renewable Electricity Production Tax Credit. This credit applies to PV, wind, and renewable-fueled cogeneration systems. It provides a 1.9 cent per

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[1] State and federal tax credits were examined only for PV systems as there were no qualifying tax credits for non-renewable cogeneration facilities and there were too few wind and biogas facilities in the SGIP for these impacts to have much effect on cost effectiveness.

[2] Provisions of the state tax credit are outlined in California Franchise Tax Board (FTB) Form 3508, Solar or Wind Energy System Credit.

[3] Provisions of the federal tax credit are outlined in Internal Revenue Service (IRS) Form 3468, Investment Credit.

kWh production tax credit. However, producers who take advantage of this credit cannot claim the larger 10% Federal tax credit. Therefore, it is not assumed to influence the economics of SGIP systems.[4]

Table 5-2: Federal Tax Credit Provisions – PV

Element	Description
Rate (%)	2001-2005: 10%
Basis ($)	■ Applies only to first 200 kW of PV system capacity ■ Tax credit rate is applied to the <u>lesser</u> of a) $4.50/Watt, or b) Cost of system after deducting value of municipal, state (e.g., SGIP), or federal incentives

Depreciation Benefits

Depreciation benefits apply both to SGIP PV and cogeneration systems. Whereas tax credits reduce tax liability directly, depreciation allowances do so indirectly. Taxable net income (i.e., profit) is reduced by a depreciation allowance prior to determination of tax liability. The economic benefit of depreciation is thus calculated as the product of the depreciation allowance and the applicable marginal tax rate. Depreciation benefits are realized at both the state and federal levels. In the case of the latter, two types of depreciation benefits exist: additional first-year "bonus" depreciation, and the applicable five-year depreciation schedule for the qualified equipment.

Key elements of applicable federal bonus depreciation provisions are summarized in Table 5-3.[5] The federal bonus depreciation rate depends on the date when the system entered service. For purposes of estimating SGIP cost-effectiveness the date when the SGIP system entered normal operations was used as the basis for assigning a bonus depreciation rate. The basis is reduced by 50% of the value of applicable federal tax credits, but is not reduced by the value of applicable state tax credits.

[4] University of North Carolina DSIRE database: http://www.dsireusa.org/dsire/library/includes/incentive2.cfm?Incentive_Code=US13F&State=Federal&currentpageid=1

[5] Provisions of the federal tax credit are outlined in Internal Revenue Service (IRS) Form 3468, Investment Credit.

Table 5-3: Federal First-Year Bonus Depreciation Provisions – PV and Cogeneration

Element	Description
Rate (%)	■ Varies depending on tax year: a) Sep. 10, 2001 – May 4, 2003: 30% b) May 5, 2003 – Dec. 31, 2004: 50%
Basis ($)	■ Cost of system after deducting value of municipal and state incentives, and after deducting 50% of value of federal tax credit.

Key elements of applicable federal five-year depreciation regulations are summarized in Table 5-4.[6]

Table 5-4: Federal Five-Year Depreciation Provisions

Element	Description
Rate (%)	Year 1: 20.00% Year 2: 32.00% Year 3: 19.20% Year 4: 11.52% Year 5: 11.52% Year 6: 5.76%
Basis ($)	■ Cost of system after deducting value of municipal and state incentives, and after deducting 50% of value of federal tax credit, and after deducting value of one-time bonus depreciation allowance.

Other Incentives

In some instances SGIP projects received financial support from programs other than the SGIP. The program having the largest influence on the SGIP cost-effectiveness evaluation is the PV incentive program sponsored by the Los Angeles Department of Water and Power (LADWP). Support from LADWP had a significant impact on the cost-effectiveness of SGIP PV projects from the participant perspective. SGIP program administrators compiled and provided data on financial support from other sources for purposes of evaluating SGIP cost-effectiveness.

Summary of Participant Benefits

To recognize variations in participant benefits across technologies, the analysis is conducted at the technology level, and then aggregated to the program level.

[6] Provisions of the federal tax credit are outlined in Internal Revenue Service (IRS) Form 3468, Investment Credit.

That is, program-level participant benefits (*ParticpantBenefits*) are expressed as:

$$(1)\quad ParticipantBenefits = \sum_{i=1}^{N} \mathrm{Re}\, dElecBills_i + ValDispFuels_i + Inc_i + IncO_i + TC_i$$

where Inc_i represents SGIP incentives, $IncO_i$ reflects other incentives, and TC_i indicates tax credits and depreciation benefits. Reductions in electric bills are computed as the sum of reductions in energy charges (*RedEnChg*) and reductions in demand charges (*RedDemChg*). These reductions take into account the specific treatments of net metering under the SGIP, which differ across DG technologies. Note that these reductions are net of any possible charges associated with the use of DG (e.g., non-bypassable charges for cogeneration systems).

5.4 Participant Costs

The benefits included in the framework for the Participant Test are listed below. In many cases these costs also apply to one or more of the other tests. In these instances the discussion of the evaluation data, assumptions, and analysis is included in Section 3. To avoid repetition these discussions are not repeated here.

- System purchase, operation, and maintenance costs (*see Section 3.1*)

The cost elements pertaining to the participant test were discussed in Section 3.

Summary of Participant Costs

Participant costs are expressed as:

$$(9)\quad ParticipantCosts = \sum_{i=1}^{N} (InstCost_i + OMCosts_i)$$

where $InstCost_i$ is the installed cost of equipment and offsets and $OMCosts_i$ reflects O&M costs. Installed costs are assumed to be incurred in the first period, and incentives are assumed to be paid in that period as well. O&M costs are recognized to occur over time, and their present values are calculated.

5.5 Participant Test Results

Two figures of merit are used to summarize results of the participant test: net participant benefits and benefit-cost ratio.

The net participant benefits of the SGIP are calculated as the difference between participant benefits and participant costs:

(15) *Net Participant Benefits = ParticipantBenefits - ParticipantCosts*

Net benefits results of the cost-effectiveness evaluation from the perspective of participants are presented in Table 5-15.

Table 5-5: Participant Test – Base Case Net Benefits Results (Net present value, millions 2004 $)

Technology	Benefits ($million)	Costs ($million)	Net Benefits ($million)
PV	$86	$97	($11)
Biogas	$12	$8	$5
Cogeneration	$290	$277	$13
ICE	$261	$241	$20
MT	$29	$36	($7)
Total	**$389**	**$38**	**$7**

A breakdown of Base Case net present value benefits is presented in Table 5-6.

Table 5-6: Participant Test – Breakdown of Base Case Benefits (Net present value, millions 2004 $)

Element	PV	Biogas	ICN	MTN
Avoided Electricity Costs	$28	$9	$203	$21
Tax Credits	$19	$0	$0	$0
Tax Depreciation Benefits	$35	$2	$31	$4
Avoided Fuel Costs	$0	$1	$28	$4
Salvage	$4	$0	$0	$0
Total	**$86**	**$12**	**$261**	**$29**

A breakdown of Base Case net present value costs is presented in Table 5-7. Fuel costs for PV and biogas are zero. The periodic maintenance cost represents replacement of inverters mid-way through the life of the system. For the cogeneration technologies, initial system costs account for approximately 30% of total costs, while fuel is the largest cost element.

Table 5-7: Participant Test – Breakdown of Base Case Costs (Net present value, millions 2004 $)

Element	PV	Biogas	ICN	MTN
Net System costs (less Incentives)	$82	$5	$67	$9
Maintenance Costs - Annual	$1	$2	$34	$5
Maintenance Costs - Periodic	$14	$1	$0	$3
Nonbypassable Charges	$0	$0	$13	$1
DG Fuel Costs	$0	$0	$127	$18
Total	**$97**	**$8**	**$241**	**$36**

Participant Test net benefits results of the cost-effectiveness evaluation for the Optimistic Case are presented in Table 5-8.

Table 5-8: Participant Test – Optimistic Case Net Benefits Results Benefits (Net present value, millions 2004 $)

Technology	Benefits ($million)	Costs ($million)	Net Benefits ($million)
PV	$86	$97	($11)
Biogas	$14	$7	$7
Cogeneration	$326	$272	$55
ICE	$294	$240	$54
MT	$32	$32	$1
Total	**$427**	**$376**	**$51**

The Participant Test benefit-cost ratio is calculated as:

$$\text{(13) } \textit{Participant Benefit-Cost Ratio} = \frac{ParticipantBenefits}{ParticipantCosts}$$

Benefit-cost ratio results of the cost-effectiveness evaluation from the perspective of SGIP participants are presented in Table 5-9.

Table 5-9: Participant Test – Benefit-Cost Ratio Results

Technology	Base Case	Optimistic Case
PV	0.88	0.89
Biogas	1.58	2.05
Cogeneration (all)	1.05	1.20
– IC Engines	1.08	1.23
– Microturbines	0.81	1.02
Total (Wtd. Avg.)	**1.02**	**1.14**

Additional discussion of the cost and benefit components, their overall impact on net present value of benefits, and the benefit-cost ratios is contained in Appendix E.

6

Nonparticipant Test

6.1 Introduction

The non-participant test evaluates the costs and benefits of the SGIP from the perspective of utility customers that did not participate in the SGIP. This test is sometimes called the ratepayer impact measure (RIM) test because its principal objective is to measure what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Costs can be conceptualized as reductions in electricity revenues from participants, which would ultimately shift the burden for rate recovery to non-participants, plus program costs that would have to be covered through rates. In general, rates will go down if the change in revenues of the program is greater than the change in utility costs. Both gas and electric utilities provided support through the SGIP. Consequently, a distinguishing characteristic of the SGIP non-participant test is that it identifies and quantifies the extent to which customers of gas utilities provide financial support for installation of SGIP systems that have only electric impacts.[1]

In this section discussions of non-participant costs and benefits costs are followed by a summary of analytic methodologies pertaining specifically to the non-participant test. This section concludes with a summary of cost-effectiveness evaluation results from the perspective of utility customers that did not participate in the SGIP. Unlike the other tests discussed above in Sections 4 and 5, non-participant tests are conducted first separately for gas and electricity utility customers, then on an overall gas and electric utility ratepayer basis.

6.2 Variations from the SPM

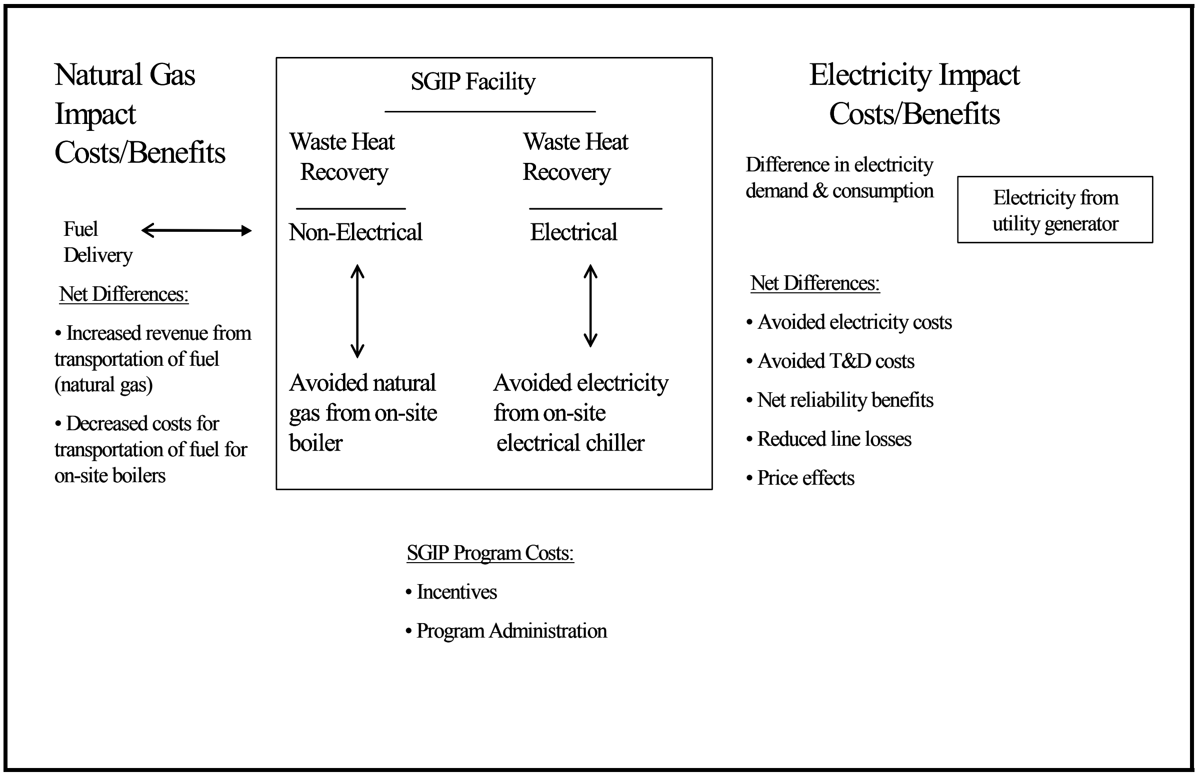
There are no significant differences from the framework approach to the non-participant test and that used in the SPM. Under the SPM and the framework, calculated benefits are the savings from avoided supply costs. These avoided costs include reduction in transmission, distribution, generation and capacity costs for those periods when load is reduced and the increase in revenues for any periods in which load is increased. Both reductions in supply

[1] This is relevant in that the non-participant test is intended to identify costs borne by ratepayers and ultimately the reasonableness of those costs. Consequently, identifying electricity benefits borne by gas ratepayers is significant in isolating out costs that might otherwise not have been borne by those ratepayers.

costs and revenue increases are calculated using net energy savings. Costs for the non-participant test in both the SPM and the framework are the program costs incurred by the utility and any other entities incurring costs involved in creating and administering the program; incentives paid to participants; decreased revenues for any period in which load has been decreased and increased supply costs for periods when load has been increased.

Figure 6-1 shows the general relationship between benefits and costs for an SGIP cogeneration facility from the non-participant perspective.

Figure 6-1: Relationship Between Benefits and Costs in Non-Participant Test



6.3 Nonparticipant Benefits

The benefits included for the non-participant test are listed below. In many cases these benefits also apply to one or more of the other tests as well. In these instances the discussion of the evaluation data, assumptions, and analysis is included in Section 3 of this report. To avoid repetition these discussions are not repeated here.

Benefits to Non-participant Electric Utility Ratepayers:

- Avoided generation costs (*see Section 3.2*)
- Avoided transmission and distribution capital costs (*see Section 3.2*)
- Reliability net benefits (*see Section 3.2*)

- Reduced line losses (*see Section 3.2*)
- Price effects (*see Section 3.2*)

Benefits to Non-participant Gas Utility Ratepayers:

- Increased revenue from transportation of fuel for gas-fired SGIP systems (*see Section 3.3*)
- Decreased costs for transportation of fuel for boilers (*see Section 3.3*)

Summary of Non-participant Benefits

The overall benefits accruing to electric ratepayers include the reductions in system costs associated with the replacement of conventional generation with DG. As with the other tests discussed above, electric ratepayer benefits are derived at the technology level, and then aggregated to the program level. That is:

$$(1) \quad ElecRatePBen = \sum_{i=1}^{N} NTG_i \times AvNPEleCosts_i$$

where NTG_i is the net-to-gross ratio associated with technology i and $AvNPEleCosts_i$ is gross avoided costs from the electric ratepayer perspective. Note that the net-to-gross ratio is required by the SPM for use in ratepayer tests.

From the perspective of gas customers, benefits (call these *GasNPBenefits*) consist of avoided fuel transportation costs associated with the use of waste heat by CHP projects (*WasteHeatBenefits*), plus increased revenues from the transportation of natural gas for gas-fired DG (*IncrGasRev*). These benefits are computed at the technology level and then summed to the program level, as given by:

$$(8) \quad GasNPBenefits = \sum_{i=1}^{N} NTG_i \times (WasteHeatBenefits_i + IncrGas\,\mathrm{Re}\,v_i)$$

Note that the use of the Net-to-Gross Ratio limits benefits to those that are attributable to the program. Waste heat benefits for each technology are estimated for the lifetime of the technology and discounted back to the present period using a discount rate equal to 8.1%.

6.4 Non-participant Costs

The costs included in the framework for the non-participant test are listed below. In many cases these costs also apply to one or more of the other tests as well. In these instances the discussion of the evaluation data, assumptions, and analysis is included in Section 3 of this report. To avoid repetition these discussions are not repeated here.

Costs to Non-participant Electric Utility Ratepayers:

- SGIP Program costs (*see discussion below*)
- Decreased revenue from sale of electricity to participants (*see Section 3.2*)

Costs to Non-participant Gas Utility Ratepayers

- SGIP Program costs (*see discussion below*)
- Decreased revenue from transportation of fuel for boilers (*see Section 3.3*)
- Increased utility costs for transportation of fuel for gas-fired SGIP systems (*see Section 3.3*)

Summary of Non-participant Costs

Electric ratepayer costs (*ElecRatePCosts*) include foregone revenues from sales of electricity ($RedElecBills_i$),[2] interconnection costs not covered by participant payments, plus electric program incentive and administration costs paid by electric customers. Electric ratepayer costs are expressed as:

$$(5) \quad ElecRatePCosts = \sum (NTG_i RedElecBills_i + IntCosts_i + IncCostE_i) + AdminCostE$$

where $IncCostE_i$ indicates electric incentives provided to technology *i*, *AdminCostE* depicts administration costs funded by electric ratepayers, and $IntCosts_i$ includes any utility interconnection costs not paid for by participants. The calculation of electric bill reductions ($RedElecBills_i$) was discussed in Section 3.

SGIP incentive and administration costs allocated to the operational projects included in the analysis are summarized in Table 6-1. In the case of SGIP projects administered by PG&E and SDREO both gas ratepayers and electric ratepayers fund the program. PG&E gas ratepayers pay 13.7% of PG&E's share[3] of program costs, while SDG&E gas ratepayer pay 21% of program costs.[4] SoCalGas and SCE are single-fuel utility companies.

2 Again, these estimated bill reductions take into account the specific treatment of net metering for qualifying technologies.

3 Public Utilities Commission of the State of California: Advice Letter 2329-G/2140-E (Pacific Gas and Electric Company ID U 39 M). July 11, 2001.

4 Public Utilities Commission of the State of California: Advice Letter 1363-E-B, March 8, 2002.

Table 6-1: SGIP Cost Summary by Ratepayer Group

	SGIP Incentives ($ MM)		
	Gas Ratepayers	Electric Ratepayers	Total
Incentives	$36.29	$102.20	$138.49
Administration	$1.78	$2.44	$4.22
Total	**$38.07**	**$104.64**	**$142.71**

6.5 Non-participant Test Results

Two figures of merit are used to summarize results of the non-participant test: net non-participant benefits and benefit-cost ratio.

The net non-participant benefits of the SGIP are calculated as the difference between non-participant benefits and non-participant costs:

(12) *Net Nonparticipant Benefits = NonparticipantBenefits - NonparticipantCosts*

Net benefits results of the cost-effectiveness evaluation from the perspective of non-participants are presented in Table 6-2 to Table 6-7. Results for the Base Case are presented in the first three of these tables.

Table 6-2: Nonparticipant Test – Net Benefits – All Ratepayers (Base Case)

Technology	Benefits ($million) No T&D	Benefits ($million) T&D	Costs ($million)	Net Benefits ($million) No T&D	Net Benefits ($million) T&D
PV	$36	$45	$144	($108)	($99)
Biogas	$5.7	$6.2	$17	($12)	($11)
Cogeneration	$253	$275	$448	($196)	($173)
ICE	$229	$249	$405	($176)	($155)
MT	$24	$26	$44	($20)	($18)
Total	**$294**	**$327**	**$610**	**($315)**	**($283)**

Table 6-2 provides estimates of the benefits, costs and net benefits to all ratepayers (electric and natural gas) from implementation of the SGIP under base case conditions. However, these same benefits can be broken out by ratepayer type to show how electricity versus natural gas ratepayers are impacted by the SGIP. Table 6-3 shows the impacts of the SGIP on only electricity ratepayers. Table 6-4 shows the impacts of the SGIP on only natural gas ratepayers.

Table 6-3: Nonparticipant Test – Net Benefits – Electric Ratepayers (Base Case)

	Benefits ($million)			Net Benefits ($million)	
Technology	No T&D	T&D	Costs ($million)	No T&D	T&D
PV	$36	$45	$130	($94)	($85)
Biogas	$5	$6	$17	($12)	($11)
Cogeneration	$230	$252	$391	($161)	($138)
ICE	$209	$229	$354	($145)	($125)
MT	$21	$23	$37	($16)	($14)
Total	**$271**	**$304**	**$538**	**($267)**	**($234)**

Table 6-4: Nonparticipant Test – Net Benefits – Gas Ratepayers (Base Case)

	Benefits ($million)			Net Benefits ($million)	
Technology	No T&D	T&D	Costs ($million)	No T&D	T&D
PV	$0	$0	$14	($14)	($14)
Biogas	$0	$0	$0	$0	$0
Cogeneration	$23	$23	$58	($35)	($35)
ICE	$20	$20	$51	($31)	($31)
MT	$3	$3	$7	($4)	($4)
Total	**$23**	**$23**	**$72**	**($49)**	**($49)**

Non-participant Test net benefits results of the cost-effectiveness evaluation for the Optimistic Case are presented in Table 6-5 to Table 6-7.

Table 6-3 and Table 6-4 show impacts of the SGIP to electricity and natural gas ratepayers under base case conditions. Table 6-5 shows the impact to all ratepayers under the optimistic case. Table 6-6 and Table 6-7 show the impacts under the optimistic case conditions separately for the electricity and natural gas ratepayers, respectively. In general, as discussed in Section 3 of this report, the optimistic case conditions involve higher capacity factors and lower O&M costs for cogeneration and biogas systems.

Table 6-5: Nonparticipant Test – Net Benefits – All Ratepayers (Optimistic)

Technology	Benefits ($million) No T&D	Benefits ($million) T&D	Costs ($million)	Net Benefits ($million) No T&D	Net Benefits ($million) T&D
PV	$36	$45	$144	($108)	($99)
Biogas	$6	$7	$18	($12)	($12)
Cogeneration	$275	$299	$480	($204)	($181)
ICE	$249	$271	$434	($184)	($162)
MT	$26	$28	$46	($20)	($18)
Total	**$317**	**$351**	**$642**	**($325)**	**($291)**

Table 6-6: Nonparticipant Test – Net Benefits – Electric Ratepayers (Optimistic Case)

Technology	Benefits ($million) No T&D	Benefits ($million) T&D	Costs ($million)	Net Benefits ($million) No T&D	Net Benefits ($million) T&D
PV	$36	$45	$130	($94)	($85)
Biogas	$6	$6	$18	($12)	($12)
Cogeneration	$247	$271	$418	($171)	($148)
ICE	$225	$246	$380	($155)	($133)
MT	$22	$24	$39	($16)	($14)
Total	**$288**	**$322**	**$566**	**($278)**	**($244)**

Table 6-7: Nonparticipant Test – Net Benefits – Gas Ratepayers (Optimistic Case)

Technology	Benefits ($million) No T&D	Benefits ($million) T&D	Costs ($million)	Net Benefits ($million) No T&D	Net Benefits ($million) T&D
PV	$0	$0	$14	($14)	($14)
Biogas	$1	$1	$0	$0	$0
Cogeneration	$28	$28	$61	($33)	($33)
ICE	$25	$25	$54	($29)	($29)
MT	$3	$3	$7	($4)	($4)
Total	**$29**	**$29**	**$76**	**($47)**	**($47)**

A breakdown of Base Case net present value benefits is presented in Table 6-8.

Table 6-8: Nonparticipant Test – Breakdown of Base Case Benefits (Net present value, millions 2004 $)

Element	PV	Biogas	ICN	MTN
Avoided Electricity Costs	$35.9	$5.3	$208.9	$21.2
Avoided T&D Costs	$9.5	$0.5	$20.6	$1.8
Increased Gas Revenues	$0.0	$0.0	$12.8	$1.6
Avoided Gas Costs (host site)	$0.0	$0.4	$7.0	$1.1
Total (Excl. T&D)	**$35.9**	**$5.7**	**$228.7**	**$23.9**
Total (Incl. T&D)	**$45.4**	**$6.2**	**$249.3**	**$25.7**

A breakdown of Base Case net present value costs is presented in Table 6-9. Fuel costs for PV are zero, and initial system costs account for 86% of total costs. The periodic maintenance cost represents replacement of inverters mid-way through the life of the system. For the cogeneration technologies initial system costs account for less than 30% of total costs, while fuel is the largest cost element.

Table 6-9: Nonparticipant Test – Breakdown of Base Case Costs (millions 2004 $)

Element	PV	Biogas	ICN	MTN
Reduced Electric Utility Sales	$46.5	$14.5	$334.0	$34.1
Increased Gas Utility Costs	$0.0	$0.0	$31.0	$4.8
Decreased Gas Utility Revenue	$0.0	$0.1	$2.7	$0.4
Incentives	$96.3	$2.5	$34.1	$4.2
Program Administration	$1.2	$0.2	$2.9	$0.3
Total	**$144.0**	**$17.2**	**$404.7**	**$43.7**

The Non-participant Test benefit-cost ratio is calculated as:

$$\text{(13) Non-participant Benefit-Cost Ratio} = \frac{NonparticipantBenefits}{NonparticipantCosts}$$

Benefit-cost ratio results of the cost-effectiveness evaluation from the perspective of SGIP non-participants are presented in Table 6-10 and Table 6-11.

Table 6-10: Nonparticipant Test – Benefit-Cost Ratio Results (Base Case)

	All Ratepayers		Electric Ratepayers		
Technology	**No T&D**	**T&D**	**No T&D**	**T&D**	**Gas Ratepayers**
PV	0.25	0.32	0.28	0.35	0.00
Biogas	0.33	0.36	0.31	0.34	1.04
Cogeneration	0.56	0.61	0.59	0.65	0.39
ICE	0.57	0.62	0.59	0.65	0.39
MT	0.55	0.59	0.58	0.63	0.39
Total	**0.48**	**0.54**	**0.50**	**0.56**	**0.32**

Table 6-11: Nonparticipant Test – Benefit-Cost Ratio Results (Optimistic Case)

	All Ratepayers		Electric Ratepayers		
Technology	**No T&D**	**T&D**	**No T&D**	**T&D**	**Gas Ratepayers**
PV	0.25	0.32	0.28	0.35	0.00
Biogas	0.34	0.37	0.31	0.34	1.37
Cogeneration	0.57	0.62	0.59	0.65	0.46
ICE	0.58	0.63	0.59	0.65	0.46
MT	0.56	0.60	0.58	0.63	0.47
Total	**0.49**	**0.55**	**0.51**	**0.57**	**0.38**

Additional discussion of the cost and benefit components, their overall impact on net present value of benefits, and the benefit-cost ratios is contained in Appendix E.

Appendix A

DG System Performance Modeling Description

A.1 Introduction

Metered data collected from a sample of operational PV and cogeneration systems were used to create 8,760-hour performance data sets intended to represent expectations regarding long-run average performance. Whereas the monitored data collected during 2003 and 2004 were used directly to calculate summary statistics reported in the impact evaluation reports, these data were subject to several modifications prior to use in the cost-effectiveness evaluation analysis. The methods used to translate monitored performance data collected from PV and cogeneration systems into typical-performance data sets used in the lifecycle cost-effectiveness evaluation are described below.

A.2 PV System Performance

Metered power output data collected from 2002 to 2004 were combined with observed weather data to develop relationships between weather and PV system power output. The observed weather parameter of principal interest is plane of array solar radiation (POASOLRAD); however, only global horizontal solar radiation data were readily available. For tilted PV systems the ratio of POASOLRAD to global horizontal solar radiation is a function of PV system configuration, hour of year, and cloud cover. A solar radiation model was used to estimate POASOLRAD values coincident with each metered power output data point.

The result of the solar radiation modeling described above is a large table containing pairs of POASOLRAD values and their corresponding PV system power output. The tables for each PV system were separated into groups based on season, hour of day, and POASOLRAD level. Table A-1 indicates the three months that are assigned to each season.

Table A-1: Basis of Season Assignments

Season	Months
Spring	March, April, May
Summer	June, July, August
Fall	September, October, November
Winter	December, January, February

The general form of the PV performance modeling is illustrated in Table A-2. These are actual data for one of the SGIP PV systems for the summer season of 2004 for the hour from noon to 1 P.M. (PDT). There are 90 PV system power output values, one for each day during this three-month period.

Table A-2: General Form of PV Performance Models

(A) SOLRAD (W/sq.m.)	(B) System Power Output (kW power output per kW of PV system size)
400 - 450	0.17
501 - 550	0.50
701 - 750	0.63, 0.67, 0.67
751 - 800	0.67, 0.67, 0.67, 0.67, 0.67, 0.63, 0.63, 0.67, 0.63, 0.67, 0.63, 0.63, 0.63, 0.67
801 - 850	0.73, 0.77, 0.73, 0.73, 0.70, 0.70, 0.73, 0.67, 0.70, 0.70, 0.70, 0.70, 0.70, 0.67, 0.70, 0.70, 0.67, 0.70
851 - 900	0.80, 0.77, 0.73, 0.73, 0.77, 0.77, 0.80, 0.77, 0.77, 0.80, 0.77, 0.77, 0.77, 0.73, 0.77, 0.73, 0.73, 0.73, 0.73, 0.73, 0.77, 0.73, 0.73, 0.77, 0.73, 0.77, 0.73, 0.77, 0.73, 0.73, 0.70, 0.73, 0.70, 0.73, 0.73, 0.67, 0.70, 0.70, 0.70
901 -950	0.73, 0.73, 0.77, 0.73, 0.77, 0.80, 0.77, 0.73, 0.70, 0.73, 0.77, 0.77, 0.73, 0.73, 0.70, 0.67

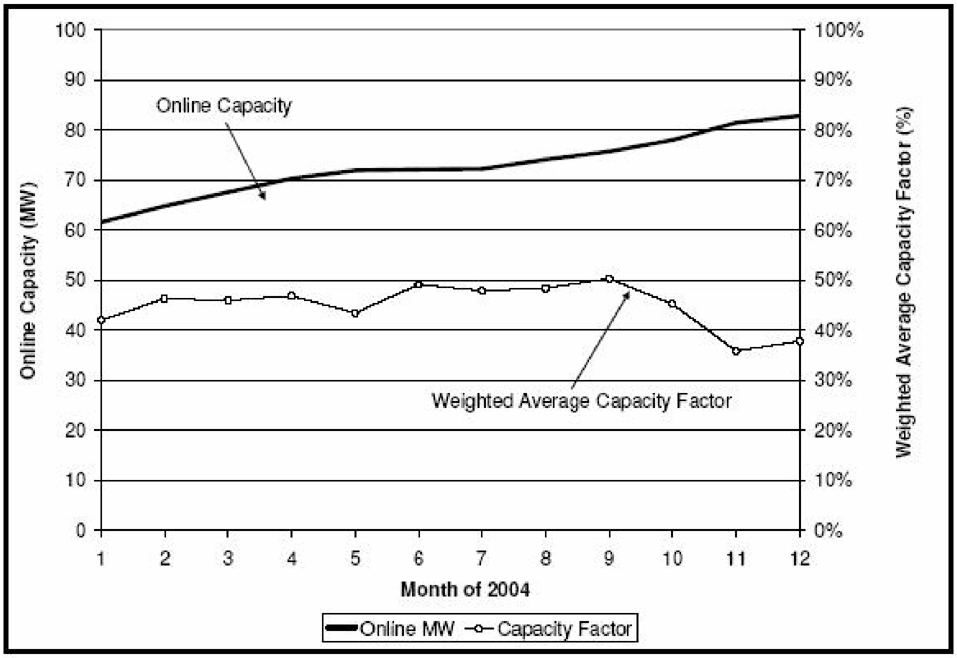
The next step in the analysis entailed estimation of POASOLRAD for each hour of an average year representative of long-run average climate, as expressed by data for a typical meteorological year (TMY). Existing 8760-hour TMY weather data sets for 12 climate zones in California served as the starting point. An 8760-hour TMY weather data set was then created for each of the operational PV systems based on facility location. Next, the orientation of each PV system was used to translate global horizontal solar radiation into estimates of the corresponding POASOLRAD. Finally, a PV system power output value was randomly selected (from Column B in Table A-2) based on POASOLRAD value.

The methodology described above was used to estimate hourly PV system power output during year one of the analysis. PV system power output for future years was estimated based on the assumption of a 0.5%/yr PV system power output degradation. This factor roughly corresponds to degradation rates embedded in PV module warranties.

A.3 Natural Gas Cogeneration System Performance

The power output of cogeneration systems depends on many factors, including facility operating schedules and the price of natural gas. The power generation characteristics of the sample of metered SGIP cogeneration systems during 2004 were summarized in the annual impact evaluation report. Monthly weighted-average capacity factors are summarized in Figure A-1 along with the monthly project on-line capacity trend.

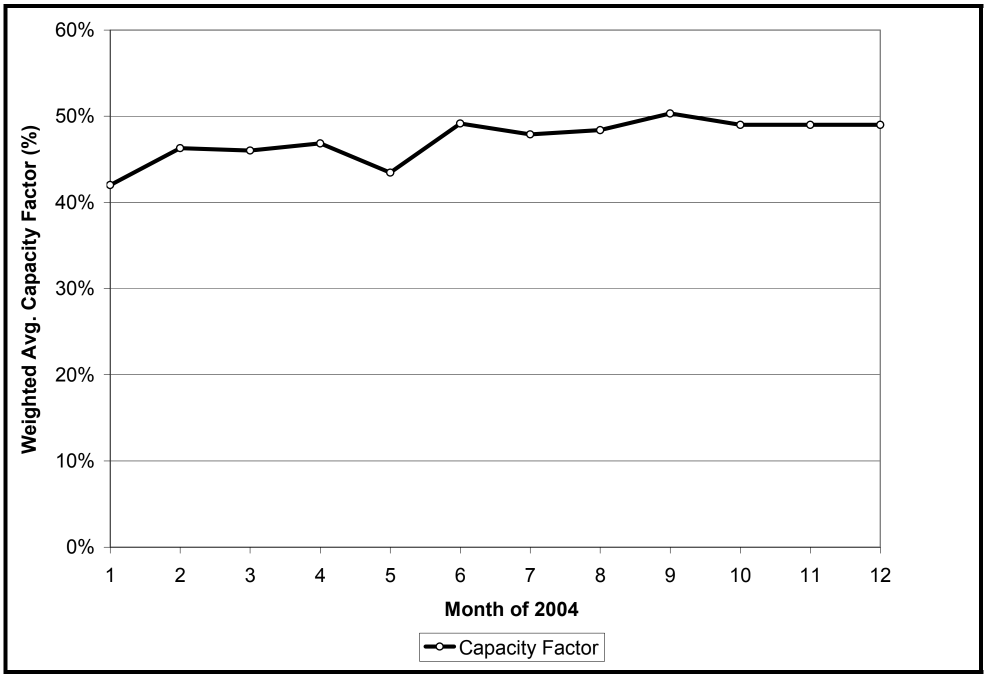
Figure A-1: Level 3/3-N/3-R On-Line MW and Average Capacity Factor (2004)



To ensure that cogeneration system performance included in the lifecycle cost-effectiveness analysis was representative of future SGIP distributed generation systems, it was necessary to adjust the available metered power generation data collected during 2004 from SGIP cogeneration systems. Interviews conducted with cogeneration system owners in early 2005 indicated that the drop-in weighted average capacity factor late in the year was due in part to abnormally high natural gas prices in Q4-2004 (i.e., facilities opted not to run cogeneration systems when natural gas prices exceeded electricity savings). A situation where natural gas prices are not reflected in electricity prices is not expected to repeat every year. Consequently, Q4-2004 metered power output data were excluded from the normalization analysis in cases where a substantial difference was observed between Q3 and Q4 project-specific capacity factor. Results of this adjustment are presented in Figure A-2, which reflects the upward adjustment of capacity factors during the fourth quarter as compared to those based on raw metered data and summarized in Figure A-1.

Metered power output data were available for approximately 40% of the total cogeneration system capacity on-line during 2004. These available metered data were used to calculate hourly ratios considered to be more representative of actual power output per unit of rebated system capacity. For periods where no metered data were available for an operational cogeneration system, estimates of power output were calculated as the product of these hourly ratios and the rebated capacity of the unmetered cogeneration system.

Figure A-2: Natural Gas Cogeneration System Base Case Capacity Factors



In addition to the value of electricity produced directly by SGIP facilities, it is necessary to consider the value of electricity savings from the substitution of recovered waste heat for uses that would otherwise require electricity. Typically, these uses involve substitution of an absorption chiller (using waste heat) for an electrical chiller. Less common applications include the use of recovered heat for applications otherwise requiring electrical resistance heating. The basis for estimates of electric savings attributable to absorption chillers is described in the following equation:

$$\begin{bmatrix} Chiller \\ Electric \\ Savings \end{bmatrix}_{sdh} \text{kWh} = \left[HEAT\right]_{sdh} \text{MBtu}_{\text{hot}} \times \left[COP_{HRAC}\right] \frac{\text{MBtu}_{\text{cold}}}{\text{MBtu}_{\text{hot}}} \times \left[EFF_{elec}\right] \frac{kWh}{Ton \cdot Hr} \times \frac{1\ Ton \cdot Hr}{12\ MBtu_{cold}}$$

Where:

Chiller Electric = Electric savings for system s on day d during hour h
Units: kWh

Savings$_{sdh}$

$HEAT_{sdh}$	=	Recovered heat delivered to the absorption chiller for system *s* on day *d* during hour *h* Units: Thousands of Btu (i.e., MBtu) Source: Metered data
COP_{HRAC}	=	Efficiency of heat recovery absorption chiller. Value: 0.6 Units: $MBtu_{cold}/MBtu_{hot}$ Basis: Assumed
EFF_{elec}	=	Efficiency of new standard-efficiency electric chiller Value: 0.6 Units: kWh/Ton·Hr Basis: Assumed

The relatively short observation period in this preliminary cost-effectiveness assessment provides a far from ideal basis for projecting power output and heat recovery performance of monitored systems 20 years into the future. Projected performance of the unmonitored systems is subject to even greater uncertainty. Many projects have recently resolved (or are still in the process of resolving) system start-up and shakedown problems; in these instances the currently available metered data may underestimate future performance. As noted in the Fourth-Year Impact Assessment, many cogeneration interview respondents anticipated that their projects would have higher capacity factors in the future. There are other instances of cogeneration system abandonment; it is possible that cogeneration systems observed to be operational in 2004 could be abandoned in the future or experience extended periods of down time due to mechanical or electrical component or system failure.

To help gauge the influence of this uncertainty on estimates of SGIP cost-effectiveness an alternative set of ENGO and Recovered Heat data was developed from the available metered data. First, monthly capacity factors (%) and heat recovery rates (MBtu/kWh) were calculated for each project where monitored data were available. The three months exhibiting the highest average capacity factor were identified and used to calculate average capacity factors and heat recovery rates that were subsequently assumed for all other months. Results of this analysis are summarized in Table A-3. On a capacity-weighted average basis the Optimistic Case annual capacity factor is 15% higher than the Base Case. The Optimistic Case annual Heat Recovery is 19% higher than the Base Case.

Table A-3: Cogeneration System Performance Scenarios

Season	Base Case	Optimistic Case
Capacity Factor (%)	47%	54%
Heat Recovery (MBtu/kWh)	3.3	3.9

Appendix B

Utility Avoided Cost Forecasts

B.1 Introduction

Utility avoided cost data forecasts play a critical role in the cost-effectiveness evaluation. Electric and gas avoided cost data prepared by Energy and Environmental Economics, Inc. (E^3) were obtained and incorporated into the analysis. The avoided cost data exhibit considerable variability. The data and their variability are summarized below.

B.2 Electric Avoided Costs

Electric avoided cost data developed by E^3 were used for purposes of evaluating cost-effectiveness from the societal and nonparticipant (i.e., ratepayer) perspectives:

Filename: cpucAvoided26.xls
Download location: www.ethree.com/CPUC/

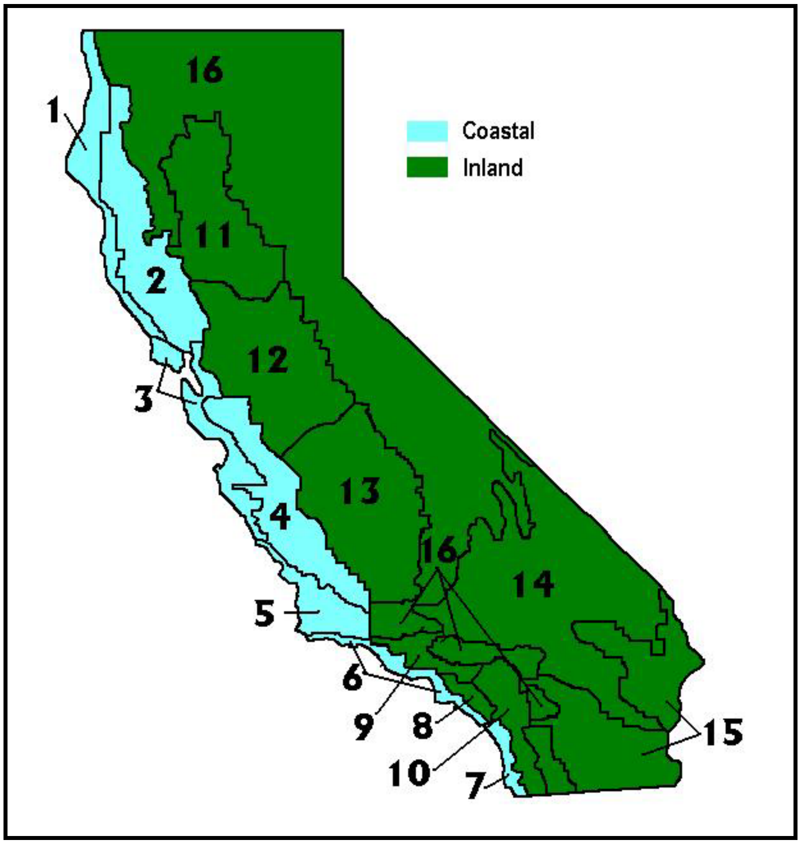
The workbook's 'Export Output to File' function was used to generate files containing electric avoided cost data for PG&E, SCE, and SDG&E. During the export process the secondary voltage level was selected. Resulting data files include nominal values for three avoided cost components: market (i.e., commodity/generation), environmental (i.e., CO_2), and transmission and distribution (T&D). An assumed inflation rate of 2% is embedded in the nominal data. Hourly electric avoided cost data exhibit considerable variability. Variability exhibited by the market and CO_2 components across utility companies is summarized for 2006 in Table B-1.

Table B-1: 2006 Annual Average Electric Avoided Cost by Utility – Market and CO_2 Components (Cents/kWh, nominal)

Component	PG&E	SCE	SDG&E
Market	7.4	7.6	7.6
CO2	0.5	0.5	0.5

The T&D values vary depending on climate zone/region.[1] A climate zone map is presented in Figure B-1.

Figure B-1: Climate Zones Map



Variability exhibited by the T&D component of electric avoided costs across utilities and climate zones for 2006 is summarized in Table B-2.

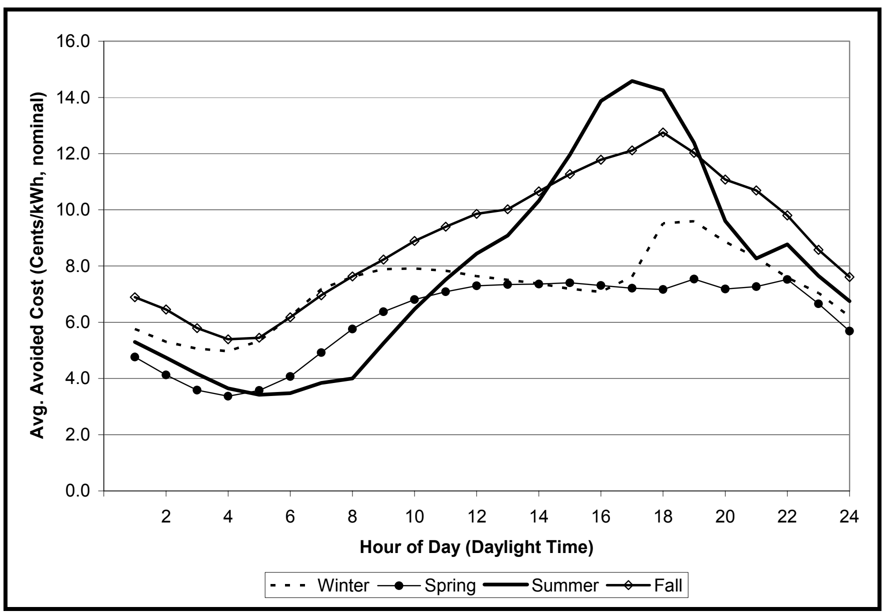
[1] The strong relationship between climate zone and T&D cost variation is explained by E3 as the influence of time dependent value of the avoided cost and that temperature alone can in fact be tied directly to hourly T&D allocation factors.

Table B-2: 2006 Annual Average Electric Avoided Cost by Utility and Climate Zone – T&D Component (Cents/kWh, nominal)

PG&E		SCE		SDG&E	
CZ1:	0.62	CZ6:	0.45	CZ7:	1.07
CZ2:	0.55	CZ8:	0.41	CZ10:	1.07
CZ3A:	0.16	CZ9:	0.49	CZ14:	1.07
CZ3B:	0.57	CZ10:	0.59	CZ15:	1.07
CZ4:	0.46	CZ13:	0.54		
CZ5:	0.45	CZ14:	0.57		
CZ11:	0.66	CZ15:	0.59		
CZ12:	0.58	CZ16:	0.67		
CZ13:	0.40				
CZ16:	0.70				
Minimum	0.16	Minimum	0.41	Minimum	1.07
Median 0.56		Median 0.56		Median 1.07	
Maximum	0.70	Maximum	0.67	Maximum	1.07

The dependence of the market component upon season and hour of day is summarized in Figure B-2, and is reflective of the dependence of avoided cost on temperature.[2] Average values range from less than 4 to more than 14 cents/kWh. Summertime values peak in the afternoon during the hour from 4:00 to 5:00 p.m. (PDT).

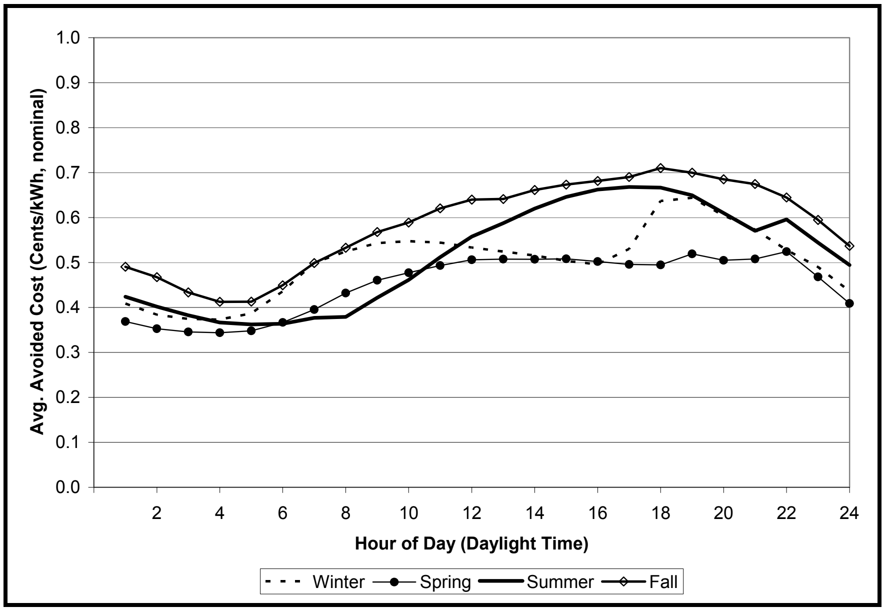
Figure B-2: 2006 Annual Average Electric Avoided Cost by Season and Hour of Day – Market Component (Cents/kWh)



The variability exhibited by the CO2 component is summarized in Figure B-3.

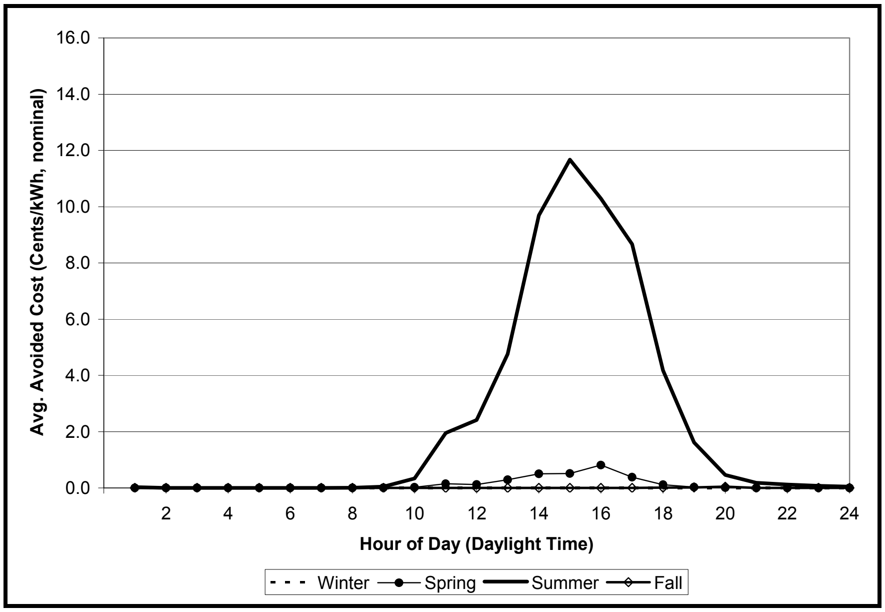
[2] For example, higher air conditioning loads will be driven by increasing daily temperatures as well as higher seasonal temperature swings.

Figure B-3: 2006 Annual Average Electric Avoided Cost by Season and Hour of Day – CO_2 Component (Cents/kWh)



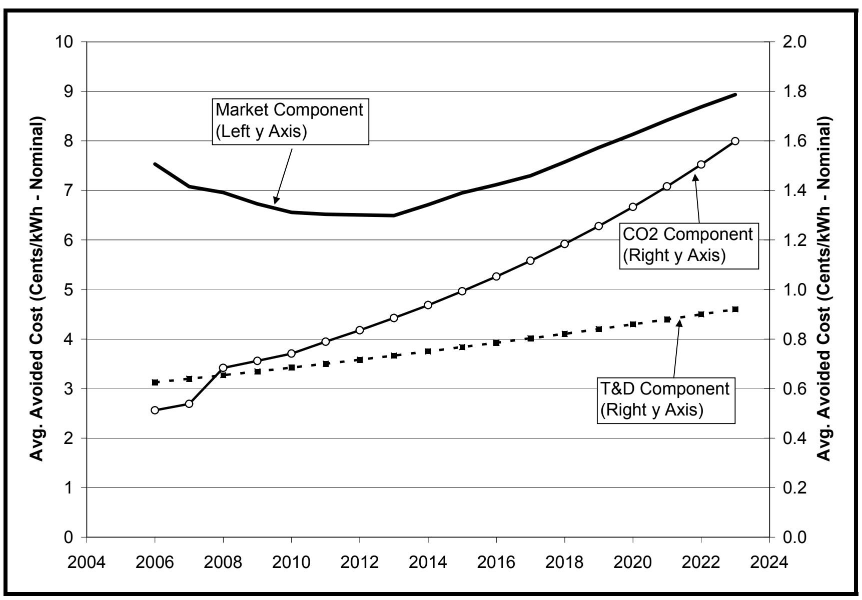
The dependence of the T&D component upon season and hour of day is summarized in Figure B-4. Average values range from 0 to nearly 12 cents/kWh. The average value in the summertime peaks in the afternoon during the hour from 2:00 to 3:00 p.m. (PDT). Seasonal averages for particular seasons tell only part of the T&D avoided cost variability story. Values for particular seasons and hours of the day also exhibit considerable variability. For example, for all of the individual summertime hours from 2:00 to 3:00 p.m. (PDT) the mean value is 11.7 cents/kWh, but individual values range from 0 to 1430 cents/kWh.

Figure B-4: 2006 Annual Average Electric Avoided Cost by Season and Hour of Day – T&D Component (Cents/kWh)



The variability exhibited by electric avoided cost data across years is summarized in Figure B-5. Data currently available from E^3 extend from 2006 onward, whereas for purposes of this cost-effectiveness analysis 2004 is assumed to be the first year of SGIP system operation. In this analysis the nominal 2006 data were also used for 2004 and 2005.

Figure B-5: Annual Average Electric Avoided Cost by Year (Cents/kWh)



B.3 Natural Gas Avoided Costs

Natural gas avoided cost data developed by E^3 were used for purposes of evaluating program cost-effectiveness:

Filename: gasModel9.xls
Download location: www.ethree.com/CPUC/

Total natural gas costs comprise a commodity component and a transportation component.[3] For this study all natural gas is assumed to be purchased under non-core tariffs. Under these tariffs the customer buys the commodity component of natural gas from a source other than the gas utility company. From the utility company's perspective, and thus from the perspective of its ratepayers, natural gas utility avoided costs are limited to the transportation component of natural gas costs. From society's perspective, natural gas avoided costs include both the commodity and transportation components.

Data for the commodity component of natural gas avoided cost were obtained from E^3 workbook 'gasModel9.xls', worksheet 'Commodity'. These values vary based on natural gas utility company, year, and month. Estimated values of the transportation component of natural gas avoided costs are based on a simplifying assumption. Specifically, the costs faced by natural gas utility companies to transport fuel used in SGIP systems are assumed to be equal to the marginal costs faced by natural gas utility companies to transport fuel to their commercial core customers. Gas transportation marginal costs for commercial core customers are found in E^3 workbook 'gasModel9.xls', worksheet 'T&D'. These costs are assumed to escalate at the general rate of inflation (2%).

Table B-3: Natural Gas Transportation Marginal Costs for 2006

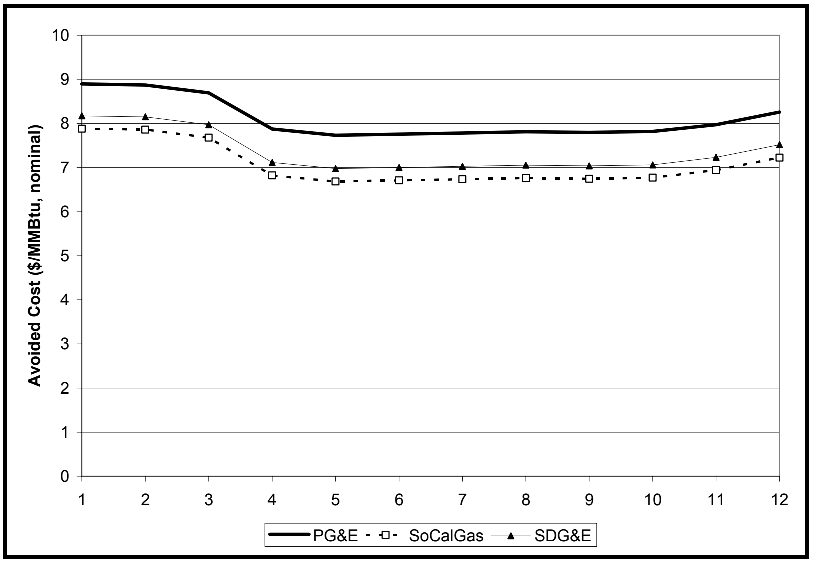
Utility Company	Cost ($/MMBtu)
PG&E	1.241
SoCalGas	0.567
SDG&E	0.858

Source: E^3 workbook 'gasModel9.xls', worksheet 'T&D'.

Resulting estimates of natural gas avoided costs from the perspective of society vary by utility company, year, and month of year. Month-to-month variability is illustrated in Figure B-6 which contains data for 2006.

[3] The workbook also treats an environmental component for NOx and CO2, however in our analysis we are treating this component outside of the E3 xls because we need to treat a variety of technologies not included among the end uses included in the E3 xls.

Figure B-6: Natural Gas Avoided Cost – Commodity + Transportation - Month-to-Month Variability for 2006



Data currently available from E[3] extend from 2006 onward, whereas for purposes of this cost-effectiveness analysis 2004 is assumed to be the first year of SGIP system operation. In this analysis the nominal 2006 data were also used for 2004 and 2005.

Appendix C

Retail Price Forecasts

C.1 Introduction

Retail electricity and natural gas price forecasts play a critical role in the cost-effectiveness evaluation. Initial electricity prices are defined based on prevailing tariffs. These initial values are extrapolated based on revenue requirement forecasts developed by electric utility companies. Natural gas retail price forecasts are included in the E^3 avoided cost models. Retail price forecasts for electricity and natural gas are described below.

C.2 Electricity

The initial electric rates used in the analysis are summarized in Table C-1.

Table C-1: Electrical Tariffs – Assumed Rates for 2004

	PG&E E-19		SCE TOU-8		SDG&E AL-TOU DER	
Time Period	**Demand $/kW**	**Energy $/kWh**	**Demand $/kW**	**Energy $/kWh**	**Demand $/kW**	**Energy $/kWh**
On-Peak-Summer	13.35	0.159	15.93	0.211	5.59	0.015
Part-Peak-Summer	3.70	0.096	3.30	0.143	N/A	0.012
Off-Peak-Summer	N/A	0.082	NA	0.101	N/A	0.011
Non-coincident-Summer	2.55	N/A	1.76	N/A	11.58	N/A
On-Peak-Winter	N/A	N/A	N/A	N/A	3.83	0.013
Part-Peak-Winter	3.65	0.102	$0.00		N/A	0.012
Off-Peak-Winter	0.00	0.082	$0.00	0.094	N/A	0.011
Non-coincident-Winter	2.55	N/A	1.76	N/A	11.58	N/A

N/A ≡ Not Applicable

The revenue requirement forecasts submitted by the electric utilities to the California Energy Commission (CEC) in connection with the 2005 Integrated Energy Policy Report (IEPR) Proceeding were used as the basis for projecting future retail electricity prices. The revenue requirement forecasts were transformed into escalation factors that were applied to the 2004 rates in Table C-1. The escalation factors are presented in Table C-2. Because the utilities' revenue requirement forecasts only extend through 2016, values for the remaining years were estimated based on an assumption of zero additional escalation in real terms.

Table C-2: Electric Retail Rate Escalation Factors

Year	Average Revenue Req't (Cents/kWh, Nominal)			Escalation Factor (Nominal)		
	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE
2004	14.35	12.96	11.28	1.00	1.00	1.00
2005	14.77	13.59	12.48	1.03	1.05	1.11
2006	14.87	13.81	13.60	1.04	1.07	1.20
2007	15.17	14.07	14.16	1.06	1.09	1.25
2008	15.46	14.86	14.31	1.08	1.15	1.27
2009	15.77	15.20	14.57	1.10	1.17	1.29
2010	16.08	15.25	14.99	1.12	1.18	1.33
2011	16.40	15.15	15.42	1.14	1.17	1.37
2012	16.73	15.63	15.66	1.17	1.21	1.39
2013	17.06	15.66	16.07	1.19	1.21	1.42
2014	17.40	16.35	16.51	1.21	1.26	1.46
2015	17.74	16.68	16.90	1.24	1.29	1.50
2016	18.10	17.01	17.47	1.26	1.31	1.55
2017	18.46	17.35	17.82	1.29	1.34	1.58
2018	18.83	17.70	18.18	1.31	1.37	1.61
2019	19.20	18.05	18.54	1.34	1.39	1.64
2020	19.59	18.41	18.91	1.36	1.42	1.68
2021	19.98	18.78	19.29	1.39	1.45	1.71
2022	20.38	19.16	19.68	1.42	1.48	1.74
2023	20.79	19.54	20.07	1.45	1.51	1.78

C.3 Natural Gas

The commodity portion of retail natural gas prices paid by operators of cogeneration systems is identical to the commodity portion of avoided costs (see Appendix B, Utility Avoided Cost Forecast). Total natural gas retail prices include this commodity component as well as a transportation charge. The E^3 electric avoided cost model includes a forecast of fuel transportation charges faced by electric generators. Operators of cogeneration systems are eligible for gas transportation service under identical tariffs. The gas transportation price forecast is included in worksheet 'Forecasts' of E^3 workbook 'gasInputs4-7-2005.xls'.

Appendix D

Framework Equations

D.1 Introduction

The purpose of this appendix is to provide a single listing of the equations used in each of the tests. It is complementary to Appendix E, which provides a single listing of the cost and benefit components used in each of the tests. The equations come directly from the March 2005 SGIP-specific framework.[1]

D.2 Societal Test

Summary of Societal Benefits

The societal benefits of the program (*SocietalBenefits*) are specified as the sum of societal benefits associated with individual technologies ($SocietalBenefits_i$):

$$(1) \quad SocietalBenefits = \sum_{i=1}^{N} NTG_i \times (AvoidedElectricCosts_i + WasteHeatBenefits_i)$$

where $AvoidedElectricCosts_i$ represents avoided electric costs associated with technology i, $WasteHeatBenefits_i$ reflects total waste heat benefits associated with technology i, and NTG_i is a net-to-gross ratio assumed for the technology in question. This net-to-gross ratio reflects the fraction of benefits that are actually attributable to the program, and is defined as the percentage of distributed generation of the technology in question that would not have been installed in the absence of the SGIP. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for both PV and cogeneration systems.

Equation (1) emphasizes the need to recognize differences in societal benefits across technologies. The analysis is done at the technology level, and then aggregated to the program level. Avoided electric costs for each technology are developed on an annual basis for each year of a lifetime that is assumed based on technology type. Annual values are then discounted back to present value. That is:

[1] Itron, "Framework for Assessing the Cost-Effectiveness of the Self-Generation Program," for the California Public Utilities Commission, March 2005

$$(2)\quad AvoidedElectricCosts_i = \sum_{t=0}^{T} \frac{AvoidedElectricCosts_{it}}{(1+d)^t}$$

Where *t* denotes the year in question, *T* is the economic lifetime assumed for the project, and *d* is a societal discount rate. For each technology, avoided electric costs are developed at the hourly level then summed to create annual values:

$$(3)\ AvoidedElectricCosts_{it} = \sum_{r=1}^{R} \sum_{h=1}^{8760} \left(DG\Delta kWh_{irh} + Dsplcd\Delta kWh_{irh}\right) \times AvCost_{irht}$$

where $DG\Delta kWh_{irh}$ is the electricity output of technology *i* in region *r*, $Dsplcd\Delta kWh_{irh}$ is the electricity savings corresponding to reduced operation of electric chillers or electric resistance heating of technology *i* in region *r*, and $AvCost_{irht}$ is the total avoided electric cost per kWh in hour *h* in year *t* in region *r* for technology *i*. This specification requires that hourly energy impacts be derived separately by technology and planning area and applied to the relevant hourly profile of avoided generation costs. The hourly energy impacts datasets were developed by Itron as part of the overall SGIP evaluation. The specific details underlying development of these datasets are included as Appendix A to this report.

The avoided electric cost rates include avoided costs of generation ($AvGCost_{hrt}$), avoided cost of transmission and distribution ($AvTDCost_{hrt}$), avoided cost of environmental externalities ($AvEnv_{ihrt}$), a reliability adder ($ReAdd_{hrt}$), and a price elasticity adder ($PEAdd_{ihrt}$). Avoided generation costs take into account line losses on displaced purchases. It should be noted again that T&D benefits are assumed to be equal to zero for the Base Case but are included in the Optimistic Case.

The equation for avoided costs is written as:

$$(4)\ AvCost_{ihrt} = AvGCost_{hrt} + AvTDCost_{hrt} + ReAdd_{hrt} + AvEnv_{ihrt} + PEAdd_{ihrt}$$

Waste heat benefits cover combined heat and power applications where recovered heat displaces natural gas use, and are computed as the present value of annual values:

$$(5)\quad WasteHeatBenefits_i = \sum_{t=1}^{T} \frac{WasteHeatBenefits_{it}}{(1+d)^t}$$

The annual values of waste heat benefits are given by:

(6) $$WasteHeatBenefits_{it} = \sum_{m=1}^{12} DisTherms_{im} \times AvGasCost_{mt}$$

where $DisTherms_{im}$ is the gas consumption displaced by technology *i* in month *m* and $AvGasCost_{mt}$ is the avoided cost of gas in month *m* and year *t*.

Summary of Societal Costs

In summary, societal costs include installed equipment costs (*InstCost*), operating and maintenance costs (*OMCost*), external environmental costs (*EnvCost*), and program administrative costs (*AdminCost*). The present value of societal costs is given by:

(7) $$SocietalCosts = \sum_{i=1}^{N} NTG_i \times (InstCost_i + OMCost_i + EnvCost_i) + AdminCost_i$$

Note that costs associated with participant activity are multiplied by the net-to-gross ratio to account for the fact that some of these costs could have been incurred in the absence of the program. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for all projects. Program administrative costs are all attributable to the program and are thus not multiplied by *NTG*.

Both installation costs and program administration costs are assumed to be incurred in the year of the program; O&M costs and external environmental costs occur over the lifetime of the DG, and the societal discount rate is used to discount annual results back to present values using:

(8) $$EnvCost_i = \sum_{t=1}^{T} \frac{EnvCost_{it}}{(1+d)^t}$$

(9) $$OMCost_i = \sum_{t=1}^{T} \frac{\left(OMCostNONFUEL_{it} + OMFuelCost_{it}\right)}{(1+d)^t}$$

Note that, for gas-fired DG applications, the fuel cost component of O&M costs is given by:

(10) $$OMFuelCost_{it} = \sum_{m=1}^{M} ThermsUse_{imt} \times AvCostGas_{mt}$$

where $ThermsUse_{imt}$ is the monthly usage of natural gas for the DG application and $AvCostGas_{mt}$ is the monthly avoided cost of gas. External environmental costs attributable to operation of SGIP cogeneration systems are given by:

$$(11)\ EnvCost_{it} = \sum_{h=1}^{8760} \left(DG\Delta kWh_{irh} \times \left(CO2_t + NOx_t \right) \right)$$

D.3 Participant Test

Summary of Participant Benefits

To recognize variations in participant benefits across technologies, the analysis is conducted at the technology level, and then aggregated to the program level. That is, program-level participant benefits (*ParticipantBenefits*) are expressed as:[2]

$$(1)\quad ParticipantBenefits = \sum_{i=1}^{N} \mathrm{Re}\, dElecBills_i + ValDispFuels_i + Inc_i + IncO_i + TC_i$$

where Inc_i represents SGIP incentives, $IncO_i$ reflects other incentives, and TC_i indicates tax credits and depreciation benefits. Reductions in electric bills are computed as the sum of reductions in energy charges (*RedEnChg*) and reductions in demand charges (*RedDemChg*). These reductions take into account the specific treatments of net metering under the SGIP, which differ across DG technologies.[3] Note that these reductions are net of any possible charges associated with the use of DG (e.g., non-bypassable charges for cogeneration systems).

$$(2)\quad RedElecBills_i = RedEnChg_i + RedDemChg_i$$

Each of these elements of bill impacts (i.e., affects on the energy bill) is computed as a present value of the associated streams of bill effects:[4]

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2 Note here that the Participant Test is based on gross, rather than net, benefits and costs. This is consistent with the SPM, which indicates that "Load impacts form Participants should be based on gross, whereas for all other tests the use of net is appropriate." (p. 27)

3 Itron assessed net metering costs based on the provisions of PUC Section 2827, which provides for net metering for customer generators with solar, wind, solar/wind hybrid, biogas digester and fuel cell systems less than 1 MW. In general, reductions in energy bills were calculated based on hourly reductions in purchases of electricity valued at the appropriate retail rates, and reductions in billing demand, valued at the appropriate demand charge component. More detailed discussion is contained in the Itron framework document.

4 It is unclear what discount rate should be used here. One could argue that participants tend to have a high time value of money, and that a relatively high discount rate should be used to bring participant benefits and costs back to present value. The SPM is silent on this issue for all of the cost-effectiveness tests, except that it suggests that a societal test, unlike other tests, should use a societal discount rate. (see p. 19) The societal

(3) $$Re\,dEnChg_i = \sum_{t=1}^{T} \frac{Re\,dEnChg_{it}}{(1+d)^{t-1}}$$

(4) $$Re\,dDemChg_i = \sum_{t=1}^{T} \frac{Re\,dDemChg_{it}}{(1+d)^{t-1}}$$

Annual reductions in energy and demand charges are computed as:

(5) $$\mathrm{Re}\,dEnChg_{it} = \sum_{i=1}^{N} \sum_{p=1}^{P} \sum_{h=1}^{8760} \Delta kWhOnSite_{ipht} \times (EnergyRate_{pht} - DLChg_{pht})$$

and

(6) $$\mathrm{Re}\,dDemChg_{it} = \sum_{i=1}^{N} \sum_{p=1}^{P} \Delta kWOnSite_{ipt} \times DemChg_{pt}$$

where $\Delta kWhOnSite_{ipht}$ and $\Delta kWOnSite_{ipt}$ indicate reductions in on-site energy use and billing demand, respectively; $EnergyRate_{pht}$ and $DemChg_{pt}$ reflect the prevailing energy and demand charges for customers on rate p; and $DLChg_{pht}$ and $SBChg_{pt}$ reflect departing load and standby charge rates, respectively.

Note that reductions in energy use reflect the provisions of net metering, if applicable, in the sense that they include any net metering credits that were ultimately used by the facility.

The value of displaced fuels for combined heat and power applications will be determined as the present value of the stream of future cash flows:

(7) $$ValDispFuels_i = \sum_{t=1}^{T} \frac{ValDispFuels_{it}}{(1+d)^{t-1}}$$

The annual value of displaced fuels will be computed as:

(8) $$ValDispFuels_{it} = \sum_{i=1}^{N} \sum_{m=1}^{12} DisTherms_{imt} PGas_{mt}$$

test is typically lower than a market rate to reflect risk pooling and spreading associated with public programs.

where $PGas_{mt}$ is the price of natural gas in month *m* and year *t*.

Summary of Participant Costs

Participant costs are expressed as:

$$(9) \quad ParticipantCosts = \sum_{i=1}^{N} (InstCost_i + OMCosts_i)$$

where $InstCost_i$ is the gross installed cost of equipment and offsets and $OMCosts_i$ reflects O&M costs. Installed costs are assumed to be incurred in the first period, and incentives are assumed to be paid in that period as well. O&M costs are recognized to occur over time, and their present values are defined as:

$$(10) \; OMCost = \sum_{t=1}^{T} \frac{\left(OMCostNONFUEL_t + OMCostFUEL_t\right)}{(1+d)^{t-1}}$$

The fuel cost component of participant O&M costs is given by:

$$(11) \qquad OMCostFuel = \sum_{t=1}^{T} \frac{FuelCost_t}{(1+d)^t}$$

where annual fuel costs are computed as:

$$(12) \; FuelCost_t = \sum_{m=1}^{M} ThermsUse_{mt} \; PriceGas_{mt}$$

where $ThermsUse_{mt}$ is the monthly usage of natural gas for the DG application and $PriceGas_{mt}$ is the monthly retail price of gas.

The non-fuel component of participant O&M costs is given by:

$$(13) \qquad OMCostNONFUEL = \sum_{t=1}^{T} \frac{MaintCost_t}{(1+d)^t}$$

where annual maintenance costs are computed as:

(14) $MaintCost_t = DG\Delta kWh_t \times Maint\_kWh_t$

where $DG\Delta kWh_t$ is the annual electric energy production for the DG application and $Maint\_kWh_t$ is the per-kWh maintenance cost for technology *i*.

D.4 Nonparticipant Test

Summary of Electric Ratepayer Nonparticipant Benefits

The overall benefits accruing to electric ratepayers include the reductions in system costs associated with the replacement of conventional generation with DG. As with the other tests discussed above, electric ratepayer benefits are derived at the technology level, and then aggregated to the program level. That is:

(1) $$ElecRatePBen = \sum_{i=1}^{N} NTG_i \times AvNPEleCosts_i$$

where NTG_i is the net-to-gross ratio associated with technology *i* and $AvNPEleCosts_i$ is gross avoided costs from the electric ratepayer perspective. Note that the net-to-gross ratio is required by the SPM for use in ratepayer tests.

The discounted value of avoided electricity costs is computed as:[5]

(2) $$AvNPEleCosts_i = \sum_{t=0}^{T} \frac{AvNPElecCosts_{it}}{(1+d)^t}$$

where $AvNPElecCosts_{it}$ represents annual avoided electric costs from the nonparticipant's view. These annual costs are computed as:

(3) $$AvNPElecCosts_{it} = \sum_{i=1}^{N} \sum_{h=1}^{8760} \Delta kWh_{irh} NPAvCost_{hrt}$$

where ΔkWh_{irh} is the hourly electricity output of technology *i* in region *r* during hour *h*, and $NPAvCost_{hrt}$ is the avoided electric cost per kWh in hour *h* in year *t* in region *r*, specified from the perspective of nonparticipants (see below).

5 Again, it is unclear which discount rate should be used for nonparticipant tests. The SPM is silent on this issue.

Elements of avoided electric costs used in the RIM, or nonparticipant test, include the avoided costs of generation ($AvGCost_{hrt}$), avoided cost of transmission and distribution ($AvTDCost_{hrt}$), an environmental adder ($EnvAdd_{hrt}$), a reliability adder ($ReAdd_{hrt}$), and a price elasticity adder ($PEAdd_{hrt}$).

Avoided costs of generation are included in this test, as is a reliability adder. These reduce revenue requirements. As was the case for the Societal Test, a zero value is assumed for T&D benefits for a Base Case assessment of the 2004 SGIP. The overall influence of this factor on program cost-effectiveness is explored with a sensitivity analysis. A price elasticity adder is included to account for price effects accruing to nonparticipants. Thus, nonparticipant avoided electricity costs are expressed as:

$$(4) \quad NPAvCost_{hrt} = AvGCost_{hrt} + AvTDCost_{hrt} + ReAdd_{hrt} + PEAdd_{hrt}$$

Summary of Gas Ratepayer Nonparticipant Benefits

From the perspective of gas customers, benefits (call these *GasNPBenefits*) consist of avoided fuel costs associated with the use of waste heat by CHP projects (*WasteHeatBenefits*), plus increased revenues from the sale of natural gas for gas-fired DG (*IncrGasRev*). These benefits are computed at the technology level and then summed to the program level, as given by:

$$(8) \quad GasNPBenefits = \sum_{i=1}^{N} NTG_i \times (WasteHeatBenefits_i + IncrGasRev_i)$$

Note that the use of the Net-to-Gross Ratio limits benefits to those that are attributable to the program.

Waste heat benefits for each technology are estimated for the lifetime of the technology and discounted back to the present period as:

$$(9) \quad WasteHeatBenefits_i = \sum_{t=1}^{T} \frac{WasteHeatBenefits_{it}}{(1+d)^t}$$

The annual values of waste heat benefits are given by:

$$(10) \quad WasteHeatBenefits_t = \sum_{i=1}^{N} \sum_{m=1}^{12} DisTherms_i \times AvGasCost_{mt}$$

where $DisTherms_{im}$ is the gas consumption displaced by technology *i* in month *m* and $AvGasCost_{mt}$ is the avoided cost of gas in month *m* and year *t*.

Revenues from the sale of natural gas as a fuel for CHP applications are written as

$$(11)\ IncrGasRev_i = \sum_{t=1}^{T} \frac{IncrGasRev_{it}}{(1+d)^t}$$

$$(12)\ IncrGasRev_{it} = \sum_{m=1}^{12} CHPTherms_{im} \times CHPGasPrice_{mt}$$

where $CHPTherms_{im}$ is the monthly use of natural gas for CHP applications using technology i and is $CHPGasPrice_{mt}$ the price of natural gas to be used in CHP applications.

Summary of Electric Ratepayer Nonparticipant Costs

Electric ratepayer costs (*ElecRatePCosts*) would include foregone revenues from sales of electricity ($RedElecBills_i$),[6] any interconnection costs not covered by participant payments, plus electric program incentive and administration costs paid by electric customers. Electric ratepayer costs can be expressed as:

$$(13)\ ElecRatePCosts = \sum (NTG_i RedElecBills_i + IntCosts_i + IncCostE_i) + AdminCostE$$

where $IncCostE_i$ indicates electric incentives provided to technology I, *AdminCostE* depicts admin costs funded by electric ratepayers, and $IntCosts_i$ includes any utility interconnection costs not paid for by participants.

Summary of Gas Ratepayer Costs

Gas ratepayer costs include foregone revenues from sales of gas for conventional applications displaced by CHP applications, as well as gas program costs.

$$(13)\ GasRatePCosts = \sum_{i=1}^{N} (NTG_i ValDispFuels_i + IncCostG_i) + AdminCostG$$

6 These estimated bill reductions will take into account the specific treatment of net metering for qualifying technologies.

where $IncCostG_i$ and $AdminCostG$ are the costs of SGIP incentives and program costs funded by gas ratepayers. The calculation of the value of displaced gas ($ValDispFuels_i$) was discussed previously. It will not be possible to disaggregate program administrative costs across technologies.

Appendix E

Detailed Results and Benefits and Cost Component Tables

E.1 Introduction

The purpose of this appendix is to provide a listing of the detailed benefit-cost results as well as the benefit and cost components used in each of the tests. It is meant to be complementary to the framework equations provided in Appendix D, and illustrate quantitatively the "inputs" and resulting "outputs" of the framework model.

E.2 Societal Test Results and Components

The societal test evaluates the costs and benefits of the SGIP from the perspective of all members of society. Benefits to society include: avoided generation costs; avoided transmission and distribution capital costs; reliability net benefits; reduced line losses; external environmental benefits from reduced grid-based generation; price effects and waste heat benefits tied to combined heat and power applications. Costs to society include: external environmental costs due to SGIP facility operation; system purchase and installation costs; operation and maintenance costs of SGIP facilities and SGIP program costs. Detailed NPV results for individual elements of the societal test analysis are presented in Section 4. Benefit and cost components making up the societal test results are presented in Table E-1 on a dollars per kilowatt-basis. These values can be viewed as "inputs" into the societal test model.

Table E-1: Societal Test - Base Case with T&D - Summary of Benefits and Cost Components ($/kW)

Benefits	PV	ICN	MTN	ICR	MTR
Avoided Electricity Costs	$1,851.94	$4,382.26	$4,565.76	$1,941.03	$2,317.83
Avoided T&D Costs	$495.03	$437.50	$394.99	$213.11	$202.73
Avoided CO2 Costs	$186.70	$460.89	$482.71	$202.42	$248.91
Waste Heat Benefits NOx	$0.00	$5.03	$7.23	$3.53	$1.71
Waste Heat Benefits CO2	$0.00	$99.39	$142.82	$69.82	$33.75
Avoided Fuel Costs (host site)	$0.00	$953.92	$1,469.92	$1,303.54	$358.38
Salvage (equipment cost)	$445.47	$0.00	$0.00	$0.00	$0.00
Total	**$2,979.13**	**$6,338.99**	**$7,063.43**	**$3,733.45**	**$3,163.31**
Costs					
System costs	$7,767.0	$1,930.8	$2,553.9	$2,461.5	$3,008.4
Maintenance Costs - Annual	$83.8	$1,193.3	$1,775.7	$1,077.6	$1,234.4
Maintenance Costs - Periodic	$1,160.4	$0.0	$1,132.8	$0.0	$1,334.3
DG NOx Costs	$0.0	$0.5	$0.1	$0.0	$0.0
DG CO2 Costs	$0.0	$388.5	$557.8	$0.0	$0.0
DG Fuel Costs	$0.0	$4,343.1	$6,208.6	$0.0	$0.0
Program Administration	$47.8	$47.8	$47.8	$47.8	$47.8
Total	**$9,059.0**	**$7,904.0**	**$12,276.6**	**$3,586.9**	**$5,624.9**
Net benefit per kW	($6,079.87)	($1,564.97)	($5,213.19)	$146.57	($2,461.60)
DG unit capacity (kW)	25,045	61,385	5,970	1,870	1,374
Benefit to Cost (B:C) Ratio	0.33	0.80	0.58	1.04	0.56

Review of these components show that avoided electricity costs comprise the single largest benefit of the program to society. Avoided fuel costs are significant for cogeneration systems fueled by natural gas, and for IC engines fueled by biogas or natural gas. T&D benefits are much smaller, but comparable across the range of technologies, with PV systems realizing the highest level of benefit.

Unsurprisingly, equipment costs represent the most significant cost component. However, the magnitude of the cost component varies considerably among the technologies. PV, at $7,767 per installed kilowatt of capacity represents a system cost that is over four times as high as the lowest cost technology (IC engines fueled with natural gas), and over 2.5 times as expensive as the next most costly technology (microturbines fueled with biogas). The impact of rising natural gas fuel costs in the latter part of 2004 is reflected in the very high DG fuel costs. The impacts of these benefit and cost components are seen in the net present value results below.

Tables Table E-2 and Table E-3 provide summary results for the base case and optimistic case societal tests, respectively. These can be viewed as “outputs” to the societal test model.

Table E-2: Summary of Societal Benefits and Cost Results (Base Case)

	NPV Benefits ($million)		NPV Costs	Net NPV Benefits ($million)	
Technology	**No T&D**	**T&D**	**($million)**	**No T&D**	**T&D**
PV	$62	$75	$227	($165)	($152)
Biogas	$11	$11	$14	($4)	($3)
Cogeneration	$402	$431	$558	($156)	($127)
ICE	$362	$389	$485	($123)	($96)
MT	$40	$42	$73	($33)	($31)
Total	**$475**	**$517**	**$800**	**($325)**	**($283)**

Table E-3: Summary of Societal Benefits and Cost Results (Optimistic Case)

	NPV Benefits ($million)		NPV Costs	Net NPV Benefits ($million)	
Technology	**No T&D**	**T&D**	**($million)**	**No T&D**	**T&D**
PV	$62	$75	$222	($159)	($147)
Biogas	$13	$14	$12	$1	$2
Cogeneration	$471	$502	$538	($67)	($36)
ICE	$424	$453	$474	($50)	($21)
MT	$47	$50	$64	($17)	($15)
Total	**$547**	**$591**	**$771**	**($225)**	**($180)**

Under the Base Case-no T&D benefits scenario, IC engines with cogeneration realize the highest NPV benefits result (again due to high avoided electricity generation costs and avoided natural gas fuel costs). However, once societal costs (i.e., high DG fuel costs) are taken into account, the net NPV benefits for IC engines drops considerably. Natural gas fueled microturbines see a similar drop for the same reason. PV systems see the largest drop, largely due to high system and periodic maintenance costs. The overall impact of the net NPV values is represented in the benefit-cost ratios. However, before addressing the benefit-cost ratios, it is important to note that the net NPV results could have been significantly different if natural gas prices had remained low (or were more accurately represented in market electricity prices) or if the system and O&M costs of PV systems were lower.

Table E-4 provides an overall summary of the benefit-cost ratios for all project types in the societal test.

Table E-4: Summary of Benefit/Cost Ratios for Societal Test

	Base Case		Optimistic Case	
Technology	**No T&D**	**T&D**	**No T&D**	**T&D**
PV	0.27	0.33	0.28	0.34
Biogas	0.74	0.78	1.12	1.18
Cogeneration	0.72	0.77	0.88	0.93
ICE	0.75	0.80	0.90	0.96
MT	0.54	0.58	0.73	0.77
Total (Wtd. Avg.)	**0.59**	**0.65**	**0.71**	**0.77**

Under the societal test-no T&D scenario, biogas-fueled systems and natural gas fueled cogeneration systems have the highest benefit-cost ratios, but these still fall below the litmus test value of 1. PV systems have a significantly lower benefit-cost ratio, indicating the negative impact of their low capacity factor (resulting in capturing less avoided electricity generation value per installed unit of power), and high system and maintenance costs. Even when T&D benefits are taken into account, the benefit-cost ratio remained significantly below the other SGIP technologies. However, it should be noted that these results reflect PV systems installed under SGIP incentive structures and in the 2004 reporting period and should not be construed as being reflective of current PV system costs or performance. From an overall program perspective, the base-case benefit-cost ratio for the portfolio of projects is relatively low (but is weighted down in part by emerging PV and microturbine technologies). Allowing for T&D benefits and increased maturity of the technologies provides a significantly higher benefit-cost ratio for the portfolio of projects. This result indicates the likelihood that the value of the SGIP to society will continue to increase significantly in the future even without special targeting of the program.

E.3 Participant Test Results and Components

The participant test evaluates the benefits and costs of the SGIP from the perspective of participants. Benefits included in the participant test include: lowered net cost of electricity; combined heat and power benefits; incentives from participating in the SGIP; tax credits and depreciation benefits and other benefits that occur from other entities but result from the participant's involvement in the program. Costs included in the participant test include: equipment purchase and installation; and operating and maintenance costs. Detailed NPV results for individual elements of the participant test analysis are presented in Section 5. Benefit and cost components making up the participant test results are presented in Table E-5 on a dollars per kilowatt-basis. These values can be viewed as "inputs" into the participant test model.

Table E-5: Participant Test – Base Case- Summary of Benefits and Cost Components ($/kW)

Benefits	PV	ICN	MTN	ICR	MTR
Avoided Electricity Costs	$1,127.05	$3,303.48	$3,463.87	$2,879.23	$2,472.55
Tax Credits	$745.43	$0.00	$0.00	$0.00	$0.00
Tax Deductions	$1,416.54	$502.61	$676.10	$660.71	$751.04
Avoided Fuel Costs	$0.00	$453.53	$699.11	$620.02	$170.31
Salvage	$152.33	$0.00	$0.00	$0.00	$0.00
Total	**$3,441.35**	**$4,259.62**	**$4,839.08**	**$4,159.96**	**$3,393.90**
Costs					
Net System Costs (Includes incentives)	$3,290.8	$1,095.1	$1,474.8	$1,450.1	$1,525.5
Maintenance Costs – Annual	$39.4	$558.5	$831.1	$504.4	$577.7
Maintenance Costs - Periodic	$558.5	$0.0	$545.2	$0.0	$642.2
Nonbypassable Charges	$0.0	$214.6	$174.4	$135.7	$128.8
DG Fuel Costs	$0.0	$2,064.6	$2,952.8	$0.0	$0.0
Total	**$3,888.6**	**$3,932.8**	**$5,978.2**	**$2,090.1**	**$2,874.3**
Net Benefit per kW	($447.28)	$326.83	($1,139.15)	$2,069.88	$519.64
DG Unit Capacity (kW)	25,045	61,385	5,970	1,870	1,374
B:C Ratio	0.88	1.08	0.81	1.99	1.18

The single largest contributor to participant benefits is deferred electricity costs (i.e., displaced retail rate electricity). There is also a significant range in the values among the technologies, with PV having a value of $1,127 per installed kW and natural gas fired microturbines having over three times that value at $3,303 per installed kW. Tax deductions are the second highest benefits to participants, with PV systems seeing the largest amount of benefit at approximately $1400 per installed kW of capacity.

System costs are the largest cost charges to participants. Note that these costs represent the actual or "net" charges to the participants (i.e., overall costs minus incentives). PV systems realize the highest costs at nearly $3300 per installed kW, which is over twice the next highest system cost (i.e., biogas-fired microturbines at approximately $1500 per installed kW). Natural gas fuel costs also represent substantial cost charges to cogeneration systems using natural gas as the primary fuel. The impacts of these benefit and cost components are seen in the net present value results in Table E-6.

Table E-6: Summary of Participant Benefits and Cost Results (Base Case)

Technology	Benefits	Costs	Net NPV Benefits
PV	$86	$97	($11)
Biogas	$12	$8	$5
Cogeneration	$290	$277	$13
ICE	$261	$241	$20
MT	$29	$36	($7)
Total	**$389**	**$382**	**$7**

In general, high system costs and overall lower deferred electricity savings tend to push the net benefit of PV systems into a negative net NPV benefit realm for participants. Although cogeneration systems enjoy lower system costs than do PV systems, high natural gas prices more than offset the difference. As a result, natural gas-fired cogeneration systems end up with modest net NPV benefit values. As a portfolio of projects, the net NPV benefit is a small but positive value.

Table E-7: Summary of Participant Benefits and Cost Results (Optimistic Case)

Technology	Benefits	Costs	Net NPV Benefits
PV	$86	$97	($11)
Biogas	$14	$7	$7
Cogeneration	$326	$272	$55
ICE	$294	$240	$54
MT	$32	$32	$1
Total	**$427**	**$376**	**$51**

Under the optimistic case, capacity factors improve and O&M costs decrease for cogeneration and biogas systems. These changes slightly improve the net NPV benefit for biogas systems, but drive up the net NPV benefits for natural gas-fired cogeneration systems by over a factor of 4. This also has the impact of increasing the overall program net NPV value by over a factor of 7.

Table E-8: Summary of Benefit/Cost Ratios for Participant Test

Technology	Base Case	Optimistic Case
PV	0.88	0.89
Biogas	1.58	2.05
Cogeneration	1.05	1.20
ICE	1.08	1.23
MT	0.81	1.02
Total	**1.02**	**1.14**

The benefit cost ratios for participants is generally good, under both the base and optimistic cases. This reflects the value of the SGIP to the participants, who realize net cost savings due to the impact of the incentives and deferred electricity or other fuel costs. As with the societal test benefit-cost ratios, it should be recognized that these results reflect a specialized set of conditions that may not be transferable to other situations and may not be indicative of the costs or benefits beyond the SGIP.

E.4 Non-Participant Test Results and Components

The non-participant test evaluates the costs and benefits of the SGIP from the perspective of utility customers that did not participate in the SGIP. This test is sometimes called the ratepayer impact measure (RIM) test because its principal objective is to measure what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Benefits in the non-participant test include reduction in transmission, distribution, generation and capacity costs for those periods when load is reduced and the increase in revenues for any periods in which load is increased. Costs include the program costs incurred by the utility and any other entities incurring costs involved in creating and administering the program; incentives paid to participants; decreased revenues for any period in which load has been decreased and increased supply costs for periods when load has been increased. Detailed NPV results for individual elements of the non-participant test analysis are presented in Section 6. Benefit and cost components making up the non-participant test results are presented in Table E-9 on a dollars per kilowatt-basis. These values can be viewed as "inputs" into the non-participant test model.

Table E-9: Non-Participant Test – Base Case – Summary of Benefits and Cost Components ($/kW)

Benefits	PV	ICN	MTN	ICR	MTR
Avoided Electric Costs	$1,432.67	$3,403.04	$3,545.16	$1,507.28	$1,799.56
Avoided T&D Costs	$379.29	$335.48	$303.67	$164.51	$155.56
Increased Gas Revenues – DG	$0.00	$208.50	$269.52	$0.00	$0.00
Avoided Gas Costs – Displaced Boiler Fuel	$0.00	$114.03	$190.59	$162.28	$46.69
Total	**$1,811.96**	**$4,061.04**	**$4,308.94**	**$1,834.06**	**$2,001.81**
Costs					
Reduced Electricity Revenues	$1,856.1	$5,440.5	$5,704.7	$4,741.8	$4,072.0
Increased Gas Delivery Costs – DG	$0.0	$504.3	$798.2	$0.0	$0.0
Decreased Gas Delivery Revenue – Displaced Boiler Fuel	$0.0	$44.4	$63.2	$58.6	$15.9
Incentives	$3,844.2	$556.2	$703.9	$656.1	$909.8
Program Administration	$47.8	$47.8	$47.8	$47.8	$47.8
Total	**$5,748.1**	**$6,593.2**	**$7,317.7**	**$5,504.3**	**$5,045.5**
Net Benefit per kW	($3,936.10)	($2,532.17)	($3,008.80)	($3,670.20)	($3,043.69)
DG Unit Capacity (kW)	25,045	61,385	5,970	1,870	1,374
B:C Ratio	0.32	0.62	0.59	0.33	0.40

As in the societal and participant tests, the single highest value benefit to non-participants is from avoided electricity generation. Similarly, because avoided electricity generation on a per kW basis tracks capacity factor, avoided electricity generation benefits are higher for cogeneration systems and lowered for PV systems. Avoided T&D costs are comparable among the PV and gas-fired cogeneration systems. On the PV side, this is largely due to the large number of installations but also reflects the higher value of peak generation delivery potentially provided by PV systems. For the cogeneration facilities, this is largely due to the relatively high capacity factors for these systems. Benefits also accrue to non-participants from the sales of natural gas to DG facilities but also from waste heat recovery that displaces additional purchases of natural gas.

In the non-participant test, the "flip-side" of avoided electricity costs are the lost revenues associated with decreased sales of grid generated electricity and net-metering of PV and biogas systems. These lost electric revenues represent the single largest cost of the SGIP to non-participants. Low capacity factor, which limited the overall value of avoided electricity generation for PV systems, now acts to limit the lost revenue from the net-metering of these systems. Conversely, cogeneration systems (with commensurately higher capacity factors and overall electricity delivery) are a significantly higher source of lost electricity revenues; representing over three times the amount of lost revenue as PV systems. Incentive payments to SGIP participants also represent a significant cost to non-participants, with PV systems representing a substantial portion of this cost. For cogeneration systems, lost revenues from avoided costs of natural gas (due to waste heat recovery system) and increased revenues from sales of natural gas to the DG cogeneration systems represent a modest cost to non-participants. How these costs and benefits impact net present values of benefits is seen below.

Table E-10: Summary of Non-Participant Benefits and Cost Results (Base Case)

	NPV Benefits ($million)		NPV Costs	Net NPV Benefits ($million)	
Technology	**No T&D**	**T&D**	**($million)**	**No T&D**	**T&D**
PV	$36	$45	$144	($108)	($99)
Biogas	$5.7	$6.2	$17	($12)	($11)
Cogeneration	$253	$275	$448	($196)	($173)
ICE	$229	$249	$405	($176)	($155)
MT	$24	$26	$44	($20)	($18)
Total	**$294**	**$327**	**$610**	**($315)**	**($283)**

Almost all of the SGIP systems end up representing substantial negative NPV benefits to non-participants. This is largely due to the lost electricity sales associated with electricity produced at the SGIP facilities and displaces electricity generated from utility facilities. However, another significant impact is due to the cost of incentives that are charged against non-participants. For natural gas-fired cogeneration systems, the impact of rising natural gas prices forced up (especially in the fourth quarter of 2004) the cost of natural gas purchases. Taking T&D benefits (from deferred construction of T&D facilities) into account provides only a marginal improvement in the net NPV benefit.

Table E-11: Summary of Non-Participant Benefits and Cost Results (Optimistic Case)

NPV Benefits ($million)			NPV Costs	Net NPV Benefits ($million)	
Technology	**No T&D**	**T&D**	**($million)**	**No T&D**	**T & D**
PV	$36	$45	$144	($108)	($99)
Biogas	$6	$7	$18	($12)	($12)
Cogeneration	$275	$299	$480	($204)	($181)
ICE	$249	$271	$434	($184)	($162)
MT	$26	$28	$46	($20)	($18)
Total	**$317**	**$351**	**$642**	**($325)**	**($291)**

Under the optimistic case, capacity factors and O&M costs are improved for cogeneration and biogas facilities. However, the increase in capacity factors simply drive up the overall electricity delivery, which results in a greater amount of lost electricity revenue. As a result, cogeneration and biogas facilities represent an even greater negative NPV benefit to non-participants under the optimistic case. PV systems, which were not assumed to have capacity factors adjusted under the optimistic case, are not affected.

Table E-12: Summary of Benefit/Cost Ratios for Non-Participant Test

	Base Case		Optimistic Case	
Technology	**No T&D**	**T&D**	**No T&D**	**T&D**
PV	0.25	0.32	0.25	0.32
Biogas	0.33	0.36	0.34	0.37
Cogeneration	0.56	0.61	0.57	0.62
ICE	0.57	0.62	0.58	0.63
MT	0.55	0.59	0.56	0.60
Total (Wtd. Avg.)	**0.48**	**0.54**	**0.49**	**0.55**

Unsurprisingly, the SGIP shows relatively low benefit-cost ratios relative to non-participants. As discussed above, this occurs largely due to the combination of lost revenues from electricity delivery, high SGIP incentives, and relatively high purchase costs of natural gas (for cogeneration facilities) and low value on T&D benefits. As noted for the societal and participant tests, these benefit-cost ratios reflect the special conditions and circumstances of the SGIP and great care should be taken in using them to assess the benefit-cost of DG systems employed in other settings.

Appendix F

Total Resource Cost Test

F.1 Introduction

The total resource cost (TRC) test evaluates the costs and benefits of the SGIP from the perspective of the utilities and their ratepayers. A distinguishing characteristic of the TRC test is that it and the Societal test are considered variants of one another. A principal difference between the two is that environmental externalities are not included in the TRC test. The TRC test also uses a higher discount rate. Section F.2 discusses the methods used to evaluate TRC benefits. Cost variables and measurement methods for the TRC test are presented in Section F.3. This section concludes with a summary of SGIP cost-effectiveness evaluation results from the perspective of the utilities and their ratepayers.

F.2 TRC Benefits

The benefits included in the TRC test are listed below. Several of these benefits also apply to one or more of the other tests. To avoid repetition in these cases discussion of the evaluation data, assumptions, and analysis pertaining to these common benefits is included in Section 3.

- Avoided generation costs (see Section 3.2)
- Avoided transmission and distribution capital costs (see Section 3.2)
- Reliability net benefits (see Section 3.2)
- Reduced line losses (see Section 3.2)
- Price effects (see Section 3.2)
- Waste heat use benefits of combined heat and power applications (see Section 3.3)
- Tax credits

Only the tax credit benefits are discussed in detail in this section because only a portion of the tax credits described in Section 3.2 is applicable to the TRC test. Methods used to treat the remaining benefit categories were discussed previously in Section 3.2 and Section 3.3.

Tax Credit Benefits

PV systems are eligible for Federal and State tax credits. Only the Federal tax credits are included in the cost-effectiveness evaluation of the SGIP.

Summary of TRC Benefits

The TRC benefits of the program (*TRCBenefits*) are specified as the sum of TRC benefits associated with individual technologies ($TRCBenefits_i$):

$$(1)\quad TRCBenefits = \sum_{i=1}^{N} NTG_i \times (AvoidedElectricCosts_i + WasteHeatBenefits_i + TCfed_i)$$

where $AvoidedElectricCosts_i$ represents avoided electric costs associated with technology *i*, $WasteHeatBenefits_i$ reflects total waste heat benefits associated with technology *i*, $TCfed_i$ are federal tax credits available for technology *i*, and NTG_i is a net-to-gross ratio assumed for the technology in question. This net-to-gross ratio reflects the fraction of benefits that are actually attributable to the program, and is defined as the percentage of distributed generation of the technology in question that would not have been installed in the absence of the SGIP. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for both PV and cogeneration systems.

F.3 TRC Costs

The cost components from Itron's framework for inclusion in the TRC test are listed below. Several of these costs also apply to one or more of the other tests. To avoid repetition in these cases discussion of the evaluation data, assumptions, and analysis pertaining to these common costs is included in Section 3.

- System purchase, operation, and maintenance costs (see Section 3.1)
- SGIP Program costs (see Section 3.4)

Summary of TRC Costs

In summary, TRC costs include installed equipment costs (*InstCost*), operating and maintenance costs (*OMCost*), and program administrative costs (*AdminCost*). The present value of TRC costs is given by:

$$(2)\quad TRCCosts = \sum_{i=1}^{N} NTG_i \times (InstCost_i + OMCost_i) + AdminCost_i$$

Note that costs associated with participant activity are multiplied by the net-to-gross ratio to account for the fact that some of these costs could have been incurred in the absence of the program. For the preliminary cost-effectiveness evaluation NTG_i is assumed equal to one for all projects. Program administrative costs are all attributable to the program and are thus not multiplied by *NTG*.

Program administration costs are assumed to be incurred in the year of the program. System loan payments and O&M costs occur over the lifetime of the DG, and the TRC Test discount rate is used to discount annual results back to present values.

F.4 Total Resource Cost Test Results

Two figures of merit are used to summarize results of the TRC test: net TRC benefits and the benefit-cost ratio. The net TRC benefits of the SGIP are calculated as the difference between TRC benefits and TRC costs:

$$(12)\ \text{Net}\ TRC\ \text{Benefits} = TRC\ \text{Benefits} - TRC\ \text{Costs}$$

TRC test net benefits results of the cost-effectiveness evaluation for the Base Case are presented in Table F-1. These results are based upon the available information from the operational projects under the SGIP as of December 31, 2004. This is the same reference point used for the program's PY2004 Impact Evaluation Report.

Table F-1: TRC Test – Base Case Net Benefits Results Summary (Net present value, millions 2004 $)

Technology	NPV Benefits ($million)		NPV Costs ($million)	Net NPV Benefits ($million)	
	No T&D	T&D		No T&D	T&D
PV	$52	$62	$229	($177)	($167)
Biogas	$8	$9	$13	($5)	($5)
Cogeneration (all)	$283	$305	$450	($167)	($145)
– IC Engine	$255	$275	$392	($137)	($116)
– Microturbine	$28	$30	$58	($30)	($28)
Total	**$343**	**$376**	**$692**	**($349)**	**($316)**

A breakdown of Base Case net present value benefits is presented in Table F-2.

Table F-2: TRC Test – Breakdown of Base Case Benefits (Net present value, millions 2004 $)

Element	PV	Biogas	ICN	MTN
Avoided Electricity Costs	$36	$5	$209	$21
Avoided T&D Costs	$9	$1	$21	$2
Avoided CO2 Costs	$0	$2	$46	$7
Waste Heat Benefits NOx	$6	$0	$0	$0
Total (Excl. T&D)	**$42**	**$8**	**$255**	**$28**
Total (Incl. T&D)	**$52**	**$8**	**$275**	**$30**

A breakdown of Base Case net present value costs is presented in Table F-3. Fuel costs for PV and Biogas systems are zero. The periodic PV maintenance cost represents replacement of inverters mid-way through the life of the system. For the cogeneration technologies, initial system costs account for approximately 30% of total costs, while fuel is the largest cost element.

Table F-3: TRC Test – Breakdown of Base Case NPV Costs (millions 2004 $)

Element	PV	Biogas	ICN	MTN
System costs	$205	$9	$123	$16
Maintenance Costs - Annual	$2	$3	$56	$8
Maintenance Costs - Periodic	$21	$1	$0	$5
DG Fuel Costs	$0	$0	$209	$29
Program Administration	$1	$0	$3	$0
Total	**$229**	**$13**	**$392**	**$58**

The influence of T&D benefits on TRC test results is indicated in Table F-1 and Table F-2. Including T&D benefits increases total net present value benefits of the evaluated group of projects by a total of 10% ($33 million). The influence of several other key factors was examined by calculating TRC test results for the optimistic case. Characteristics differentiating the base and optimistic cases are presented in Table F-4.

Table F-4: Comparison of Base and Optimistic Cases

Technology	Factor		Base Case	Optimistic Case
PV	Annual O&M	(Cents/kWh)	0.4	0.2
	Periodic O&M	(% of System Cost)	20%	10%
Biogas	Annual O&M	(Cents/kWh)	3.1	1.5
	Capacity Factor	(%, Weighted Avg.)	40%	43%
ICN	Annual O&M	(Cents/kWh)	2.0	1.0
	Capacity Factor	(%, Weighted Avg.)	47%	49%
MTN	Annual O&M	(Cents/kWh)	2.6	0.6
	Periodic O&M	(% of System Cost)	60%	30%
	Capacity Factor	(%, Weighted Avg.)	47%	55%
Cogeneration	Heat Recovery Rate	(MBtu/kWh, Avg.)	3.3	5.0

TRC test net benefits results of the cost-effectiveness evaluation for the Optimistic Case are presented in Table F-5. For cogeneration systems the higher capacity factors increase costs for fuel purchases as well as benefits (e.g., electric energy production).

Table F-5: TRC Test – Benefits Results (Optimistic Case)

Technology	NPV Benefits ($million)		NPV Costs ($million)	Net NPV Benefits ($million)	
	No T&D	T&D		No T&D	T&D
PV	$52	$62	$217	($165)	($156)
Biogas	$10	$11	$11	($1)	($0)
Cogeneration (all)	$332	$355	$429	($97)	($74)
– IC Engine	$299	$320	$378	($80)	($58)
– Microturbine	$33	$35	$51	($18)	($16)
Total	**$394**	**$428**	**$657**	**($263)**	**($230)**

The TRC benefit-cost ratio is calculated as:

$$(3)\quad \textit{TRC Benefit-Cost Ratio} = \frac{TRCBenefits}{TRCCosts}$$

Benefit-cost ratio results of the cost-effectiveness evaluation from the TRC perspective are presented in Table F-6. For all cogeneration systems, when excluding T&D benefits the optimistic cost and performance assumptions result in a 22% increase in benefit-cost ratio. The addition of T&D benefits increases the benefit-cost ratio result of PV by 17% and of cogeneration by 8%. The difference is attributable to the fact that PV system energy production occurs exclusively during daylight hours when T&D benefits occur.

Table F-6: TRC Test – Benefit-Cost Ratio Results

Technology	Base Case No T&D	Base Case T&D	Optimistic Case No T&D	Optimistic Case T&D
PV	0.23	0.27	0.24	0.28
Biogas	0.61	0.65	0.92	0.97
Cogeneration (all)	0.63	0.68	0.77	0.83
– IC Engine	0.65	0.70	0.79	0.85
– Microturbine	0.48	0.51	0.65	0.69
Total (Wtd. Avg.)	**0.50**	**0.54**	**0.60**	**0.65**