ORNL/TM-2005/109

DISTRIBUTED ENERGY PROGRAM **REPORT**

EXPLORING DISTRIBUTED ENERGY ALTERNATIVES TO ELECTRICAL DISTRIBUTION GRID EXPANSION

In Southern California Edison Service Territory

December 2005

By

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U.S. Department of Energy
Energy Efficiency and Renewable Energy
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Gas Technology Institute
Distributed Energy Resources Center
GTI Projects: 20067, 15064, 15472, 15437

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Gas Technology Institute (GTI) would like to thank our sponsors: the U.S. Department of Energy, Gas Research Institute, American Electric Power Company, and GTI's Distributed Generation Collaborative Program, consisting of American Electric Power, Alagasco, California Energy Commission, City Public Service, Keyspan Energy, Memphis Light Gas and Water, Public Gas Investment Pool, and Questar Corporation.

We would also like to thank the members of our steering committee who provided expert advice by way of in-kind support for the study: Consolidated Edison Company, First Energy, and especially Southern California Edison, who allowed its distribution circuits to be the case studies for the project and provided abundant data to support the research. Other participants on the steering committee included Energetics Inc, Distributed Utility Associates, California Energy Commission, National Energy Technology Laboratory, and Oak Ridge National Laboratory.

Finally, we would like to thank our contracted organizations for their professional services: Virginia Polytechnic Institute, Redwood Power Company, Energetics, and especially American Electric Power for providing an advanced energy system demonstration on one of its distribution system circuits.

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EXECUTIVE SUMMARY

Distributed energy (DE) technologies have received much attention for the energy savings and electric power reliability assurances that may be achieved by their widespread adoption. Fueling the attention have been the desires to globally reduce greenhouse gas emissions and concern about easing power transmission and distribution system capacity limitations and congestion. However, these benefits may come at a cost to the electric utility companies in terms of lost revenue and concerns with interconnection on the distribution system. This study assesses the costs and benefits of DE to both consumers and distribution utilities and expands upon a precursory study done with Detroit Edison (DTE)[1], by evaluating the combined impact of DE, energy-efficiency, photovoltaics (a use of solar energy), and demand response that will shape the grid of the future.

This study was funded by the U.S. Department of Energy (DOE), Gas Research Institute (GRI), American Electric Power (AEP), and Gas Technology Institute's (GTI) Distributed Energy Collaborative Program (DECP). It focuses on two real Southern California Edison (SCE) circuits, a 13 MW suburban circuit fictitiously named Justice on the Lincoln substation, and an 8 MW rural circuit fictitiously named Prosper on the Washington Substation. The primary objectives of the study were threefold:

1. Evaluate the potential for using advanced energy technologies, including DE, energy-efficiency (EE), demand response, electricity storage, and photovoltaics (PV), to reshape electric load curves by reducing peak demand, for real circuits.
2. Investigate the potential impact on guiding technology deployment and managing operation in a way that benefits both utilities and their customers by:
    a. Improving grid load factor for utilities.
    b. Reducing energy costs for customers.
    c. Optimizing electric demand growth.
3. Demonstrate benefits by reporting on a recently installed advanced energy system at a utility customer site.

This study showed that advanced energy technologies are economical for many customers on the two SCE circuits analyzed, providing certain customers with considerable energy cost savings. Using reasonable assumptions about market penetration, the study showed that adding distributed generation would reduce peak demand on the two circuits enough to defer the need to upgrade circuit capacity. If the DE is optimally targeted, the deferral could economically benefit SCE, with cost savings that outweigh the lost revenues due to lower sales of electricity. To a lesser extent, economically justifiable energy-efficiency, photovoltaic technologies, and demand response could also help defer circuit capacity upgrades by reducing demand.

High electricity prices and state policy and incentives have already resulted in accelerated customer investment in advanced energy technology in California. Figures ES-1 and ES-2 show how DE, EE, and PV technologies, if only deployed moderately on the SCE circuits within the

[1] John Kelly, Tim Kingston, Jay Wrobel, Economic Potential of CHP In Detroit Edison Service Area: The Customer Perspective, ORNL/TM-2003/251, June 2003

next ten years, can greatly reduce peak loads. Demand response strategies, such as thermostat setback and light dimming, can be leveraged to further manage up to 8% of the circuit peak load.

Figure ES-1
Overall Impact of DE, EE, and PV
On the SCE Suburban Circuit

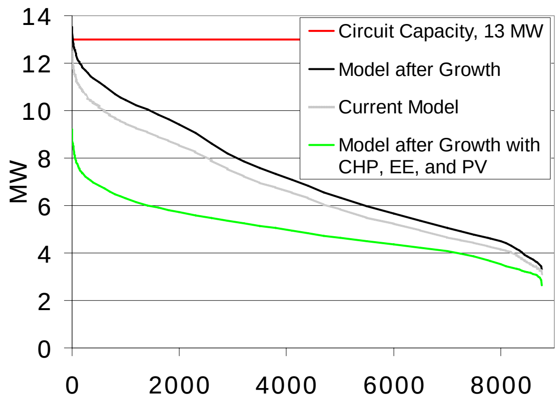
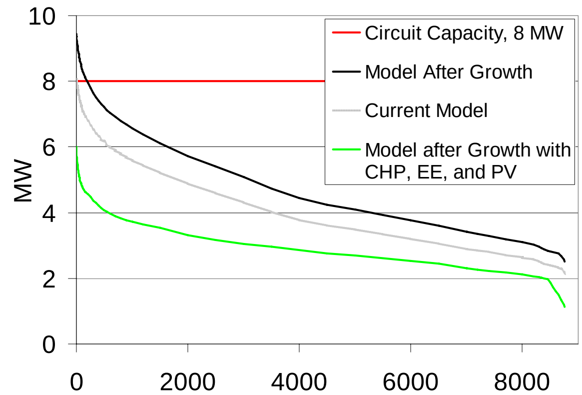
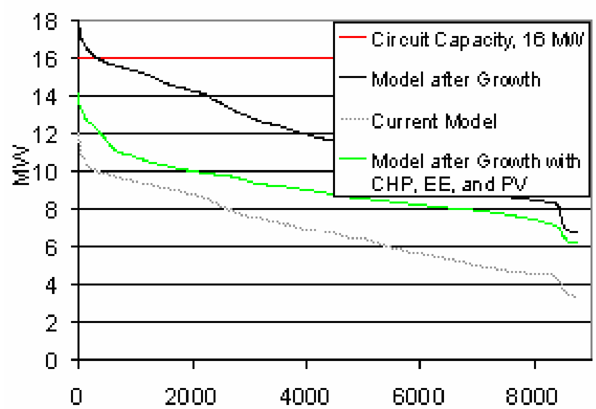


Figure ES-2
Overall Impact of DE, EE, and PV
On the SCE Rural Circuit



The SCE circuits, already exhibiting a slow rate of load growth, are susceptible to a reduction in electricity sales revenue should customers respond to current market conditions by investing in advanced energy technologies. Therefore, a desirable scenario for the utility would be to encourage advanced energy investments that would reduce the demand enough to defer circuit expansion, but maintain the existing level of energy sales. In contrast to the SCE circuits, the DTE circuit, evaluated previously and shown in Figure ES-3, had very fast load growth and customer investment in advanced energy technologies was predicted to be significantly lower. In that case, advanced energy investments would not have been sufficient to defer circuit expansion; so that reductions in the utility's future electricity sales revenue were not counterbalanced by any savings in circuit expansion costs.

Figure ES-3
Overall Impact of DE, EE and PV
On the DTE Suburban Circuit



Results from the more recent SCE study clearly reveal the potential for targeting private investment in technology with policy and incentives on areas of the grid that will become constrained due to electric load growth. Through appropriate policy and targeted incentives, utilities and policy makers could influence the amount of DE, EE, and PV that is deployed on selected circuits and tailor ideal scenarios such that energy consumption and demand is sufficient to defer circuit expansion without an adverse effect on the utility's net revenues. California and other states have aggressively implemented successful and innovative policies that can increase the deployment of load shaping technologies by targeting and influencing private investment. Those policies and some adopting states include:

- Waiving standby charges for capacity-constrained areas of the system (California and New York).
- Focusing incentives on capacity-constrained areas (Connecticut).
- Applying and optimizing stepped electric demand charges or time-of-use electric rates that increase as electric load increases during the day (New York, Illinois, Texas, and California). California and Texas have implemented three-tier demand charges.
- Implementing off-peak electric rates that are below the cost of operating DE (Illinois, Michigan, and Minnesota).
- Implementing reduced natural gas rates for on-peak DE (New York).

Distributed generation systems could be owned by the utility or by its customers, with the choice depending on the specifics of each circuit and each installation. Portable electricity generation, using natural-gas-fired machines, or energy storage, can be used to meet the peak demand to defer distribution system upgrades. By implementing portable peak shaving systems, utilities could:

- Provide additional time for more robust distribution upgrades.
- Provide additional time for private investment in technology to be effective.
- Relocate DE systems to other grid locations to provide further cost deferrals. This portability can make the DE system economically attractive, even if the deferred savings at one particular location are less than the initial installed cost of the DE.

Benefits of portable DE were realized in a demonstration project conducted by AEP. AEP deferred a major capital investment in transmission cost for one year by using a 600 kW portable generator. The deferral was financially attractive to the utility and provided system planners with sufficient time to implement a plan to upgrade the station facilities.

SUMMARY OF KEY FINDINGS

- **Using customer-owned advanced energy technologies on the Justice and Prosper circuits to defer circuit expansion could be an economical choice for SCE, depending on the marginal T&D upgrade cost estimates and the amount of load reduced on the circuit due to customer-owned technologies.**
- **SCE's historical data indicates that adding a 13 MW circuit to the Lincoln substation to relieve load on the Justice circuit, costs about $746,000 or $57/kW. Taking into account additional revenue from load growth and assuming a new circuit is needed, a capital investment of $746,000 for a new 13 MW circuit is the most economical long-term investment for the utility, if substantial deployment of customer-owned advanced energy technologies does not occur.**
- **If customers on the Justice and Prosper circuits install advanced energy technologies at capacities predicted in this study to be economical, SCE would incur substantial revenue loss. The losses would be compounded if the customers install the technologies and SCE installs an ultimately unnecessary circuit that effectively becomes a stranded asset.**
- **One of the premises of promoting customer-owned advanced energy technologies on selected circuits for load relief is that those circuits with the greatest upgrade costs would be chosen. This is especially important because transmission and distribution expansion cost estimates are reported to range from less than $100/kW to well over $3,000/kW.**
- **If a new 13 MW circuit that cost $2 million ($154/kW) or more is required to relieve load on the Justice circuit, customer-installed technologies could be an economical solution for SCE to defer the need for the new circuit. However, the amount of load reduction from the technologies would have to be considerably less (about 50% less) than the load reduction predicted in this study. Furthermore, the deployment of the technologies would have to be gradual so that load reduction is at nearly the same pace as base load growth.**
- **Through appropriate electricity price signals and targeted incentives, utilities could influence the amount of advanced energy technology deployed on selected circuits, thereby governing load reduction as necessary and economical.**
- **Transmission and distribution (T&D) capacity expansion investments may become stranded resources in the study area if moderate deployment of advanced energy technologies and the corresponding load reductions occur so that the capacity is not used.**
- **DE technologies alone or EE technologies alone could provide enough demand reduction to defer an upgrade to the Justice circuit. However, PV technologies alone would not provide enough demand reduction to defer an upgrade to Justice.**
- **DE technologies alone could provide enough demand reduction to defer an upgrade to the Prosper circuit. However, EE technologies alone or PV technologies alone would not provide enough demand reduction to defer an upgrade to Prosper.**
- **There are several factors that make DE resources an economic choice in this area. First, the utility rates are significantly greater than the operating cost of DE systems during on-peak periods. Second, the state of California offers significant incentives that effectively reduce the capital cost of installed DE resources. Third, the interconnection requirements are well established by California's Rule 21.**
- **The average installed cost allowance needed to attain a 5-year payback return for a typical CHP installation on both circuits is $900/kW. The generally higher average installation cost (roughly $1,300/kW after existing incentives) of the DE technologies considered in this study is the primary factor limiting greater customer adoption.**

- **If adding a 13 MW circuit to a substation costs about $746,000, as SCE's historical data indicates, the annual carrying cost would be $90,000/year with a 12% fixed charge rate. For the expected growth rate on the two circuits considered, this cost could be deferred for a year with a much smaller DE installation of less than 200 kW. Disregarding utility revenue growth, the utility's annual deferral avoided cost would be more than $450/kW of installed DE.**
- **As required by the California PUC, SCE must issue an RFP for DE to meet capacity requirements at specified locations. If SCE sets the value of the deferral benefit at $400/kW of installed DE, the $1,300/kW installation cost used in this study would be reduced to $900/kW. The reduction would improve customer adoption of DE and provide SCE with greater possibilities for deferring the targeted circuit upgrades.**
- **There are several dairy farms on the Prosper circuit. The dairy economics, based upon California's incipient agricultural emissions regulations, are extremely favorable to DE. The emissions regulations can be met by using methane-producing digester systems that offset traditional fuel costs.**
- **For the average dairy farm on the Prosper circuit, a CHP/digester installation could cost up to $5,900/kW and still provide a 5-year payback. Dairy power projects have very good economic potential and could be environmentally beneficial. However, the market seems to be relatively untapped.**
- **A compelling economic case can be made for using utility-owned portable generation and energy storage devices to defer the two circuit upgrades.**
- **Thermostat setback and light dimming are two demand response strategies that could be viable options for locally targeted demand reduction (2% to 3% of peak demand) on the two circuits. These demand response strategies combined with others could be leveraged to manage up to 8% of the circuit peak load.**
- **Voltage flicker, one of the most significant concerns utilities have with respect to circuit reliability and power quality, would not be an issue with any of the proposed DE penetration scenarios on the Justice Circuit.**
- **The probability that two thirds of the proposed 4,200 kW of distributed generation in this study will be available from the CHP systems on the Justice circuit, is 98.6%.**
- **The average installed cost allowance to attain 5-year payback returns for EE installations on both circuits is between $\$3.9/ft^2$ and $\$7.4/ft^2$. The average premium for USGBC green buildings is $\$3/ft^2$ to $\$5/ft^2$.**
- **The average installed cost allowance needed to attain a 5-year payback return for a PV installation on both circuits is $1000/kW. The higher installation cost used for the study (i.e. $1,800/kW - including incentives) is the primary factor limiting greater customer adoption. Without incentives, the installation cost for PV is estimated to be $9,000/kW.**
- **The proposed California Air Regulatory Board (CARB) 2007 emissions requirements are causing concern among the DG community. Some reviewers contend that reciprocating engine systems, the dominant DE technology for installations smaller than 5 MW, will not be able to meet the proposed emissions requirements until 2010 and that the market penetration for such systems will therefore be negligible. However, other sources indicate that lean-burn engine systems are currently available that satisfy the CHP system emissions requirements, if not the power only requirements.**

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Additional notes are annotated with roman numerals throughout this report and are listed in the Notes Section.

BACKGROUND

California and other states have aggressively implemented successful and innovative policies that can increase the deployment of load shaping technologies by targeting and influencing private investment. Those policies and some adopting states include:

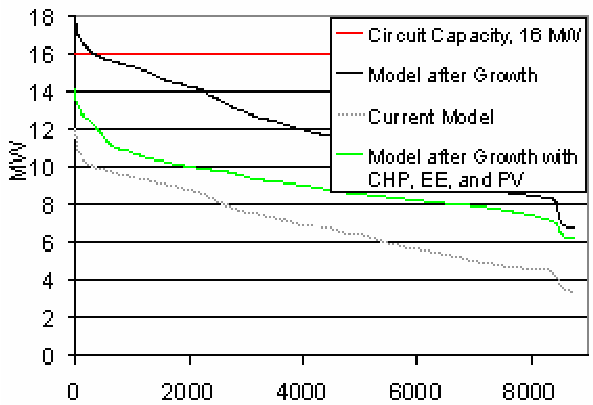
- Waiving standby charges for capacity-constrained areas of the system (California and New York).
- Focusing incentives on capacity-constrained areas (Connecticut).
- Applying and optimizing stepped electric demand charges or time-of-use electric rates that increase as electric load increases during the day (New York, Illinois, Texas, and California). California and Texas have implemented three-tier demand charges.
- Implementing off-peak electric rates that are below the cost of operating DE (Illinois, Michigan, and Minnesota).
- Implementing reduced natural gas rates for on-peak DE (New York).

In light of these activities, DOE commissioned two studies to assess the costs and benefits of Distributed Energy (DE) technologies to consumers and distribution utilities and to better understand the effect of DE, energy-efficiency, and photovoltaics (a use of solar energy) on the grid at the circuit level. The initial case study of a DTE Energy (DTE) radial circuit in Ann Arbor, Michigan explored DE market penetration based on local customer economics, the resulting impact on that particular circuit, and the possible effect on future load growth on the circuit.[1] The second case study, reported herein, focuses on two Southern California Edison (SCE) radial circuits near Los Angeles. It expands upon the goals of the first study to: evaluate the potential to reshape electric load curves, improve energy utilization efficiency in ways that benefit both utilities and their customers, and demonstrate the benefits by reporting on an advanced energy system recently installed at a utility customer site.

The initial case study, in cooperation with DTE, analyzed a 16 MW grid circuit to determine if there were economic incentives to use DE systems that would forestall a near-term need to increase grid circuit capacity. Increasing circuit capacity would have enabled the circuit to meet consumer's energy demands at all times, but it would not have improved the circuit's load factor. The analysis spanned 12 years, to a planning horizon of 2015, but the demand for power was expected to exceed the grid circuit capacity within one year. The analysis was based on economics and gave no financial credit for improved power reliability or mitigation of environmental impacts.

The study revealed that a combination of distributed energy, renewable energy and other energy efficient technologies along with demand response could have delayed and possibly avoided the circuit capacity expansion, as shown in Figure 1. However, based on current technology and business rules, the study revealed that DE penetration on the selected circuit was not expected to forestall the need to upgrade the grid circuit capacity unless DE economics improved and interconnection barriers were removed. Currently, a variety of economic, technical, business-practice, and regulatory barriers can discourage DE investment in the U.S. market.[2] In particular, DTE and other Midwest and Southeast on-peak and off-peak electric rates are relatively low, minimizing operational savings. Before the initial case study was completed, the utility expanded the capacity of the circuit to 22 MW, which significantly decreased the circuit's overall load factor.

Figure 1 - Overall Impact of DE, EE and PV on the DTE Suburban Circuit



The current case study, in cooperation with SCE, built upon the lessons learned during the initial study while leveraging an expert steering committee to provide a broad scope of practical advice. The committee included GTI, four utilities, four government agencies, and four consulting firms. The committee members included:

1. Utilities
   a. Southern California Edison
   b. American Electric Power
   c. Consolidated Edison
   d. First Energy
2. Government Agencies
   a. U.S. Department of Energy (DOE)
   b. Oak Ridge National Laboratory (ORNL)
   c. National Energy Technology Laboratory (NETL)
   d. California Energy Commission (CEC)
3. Consulting
   a. Energetics Inc.
   b. Distributed Utility Associates
   c. Virginia Polytechnic Institute
   d. Redwood Power
      i. Equity Office Partners
      ii. MPE Consulting
      iii. XNERGY

This analysis spanned 10 years, to a planning horizon of 2015, but the demand for power was expected to exceed each of the circuit capacities within one to two years. As with the initial study, this analysis is based on the economics of today's markets and thus gives no financial credit for improved power reliability or mitigation of environmental impacts.

Before this study was completed, the utility relieved one of the overburdened circuits by transferring a very large industrial facility to a nearby circuit. This solution served the utility well but is not always a viable option.

PROGRAM OBJECTIVES

The U.S. Department of Energy (DOE) is committed to reducing America's dependence on foreign oil and developing energy-efficient technologies for buildings, homes, transportation, power systems and industry. DOE established the Distributed Energy Program because distributed energy offers solutions to many of the nation's most pressing energy and electric power problems, including blackouts and brownouts, energy security concerns, power quality issues, tighter emissions standards, transmission bottlenecks, and the desire for greater control over energy costs.

Distributed energy technologies have received much attention for the energy savings and electric power reliability assurances that may be achieved by their widespread adoption. Fueling the attention has been the desire to globally reduce greenhouse gas emissions and concern about easing power transmission and distribution system capacity limitations and congestion. However, these benefits may come at a cost to the electric utility companies in terms of lost revenue and concerns with interconnection on the distribution system. It is important to assess the costs and benefits of DE to both consumers and distribution utilities and to understand the effect of DE, energy-efficiency, and photovoltaics on the grid at the circuit level.[1,3]

A number of studies have been done to estimate the market potential of DE and the possible impact on utilities, both economic and technical.[4,5,6,7,8] However, most of these studies have looked at the broad national picture, or at regional generalities. GTI, DOE, and members of the steering committee embarked on this study to determine the impact of DE on a real utility circuit, with all its real world complexities.

This case study focuses on two SCE circuits and was funded by DOE, GRI, AEP, and DECP.[i] The objectives of the study were to:

1. Evaluate the potential for using advanced energy technologies, including DE, energy-efficiency (EE), demand response, electricity storage, and photovoltaics (PV), to reshape electric load curves by reducing peak demand for real circuits.
2. Investigate the potential impact of guiding technology deployment and managing operation in a way that benefits both utilities and their customers by:
    a. Improving grid load factor for utilities.
    b. Reducing energy costs for customers.
    c. Optimizing electric demand growth.
3. Demonstrate benefits by reporting on a recently installed advanced energy system at a utility customer site.

Report Organization

The technical sections of this report are organized to cover the myriad components of the project. Because the scope of the project was so broad, the objectives of each section are listed here and are repeated at the beginning of each section.

Circuit Assessment and Selections
Strategically select two circuits for evaluation that are nearing their capacity, are conducive to advanced energy technologies, and are somewhat representative of typical SCE circuits serving the region.

Methodology
Define the technical approach and key assumptions used to model the current circuit load profiles and the circuit impact analysis; key assumptions include technologies and cost, existing market incentives, and expected customer adoption of technologies.

Baseline Circuit Analysis
Illustrate the circuit load profile models, based on aggregate TMY2 building models, as compared to the actual 2004 circuit load profiles provided by SCE.

Circuit Impact Analysis
Illustrate the impact of DE, EE, and PV technologies on the circuit load profile models given the expected customer adoption of the technologies in the next 10 years.

Utility Economics
Establish marginal transmission and distribution cost estimates and the economics for customer-owned and utility-owned DE.

Demand Response
Summarize the overall potential impact of demand response and specifically illustrate the impact of thermostat setback and light dimming on the circuits.

Advanced Energy System Demonstration
Document a successfully installed, utility-owned portable DE demonstration system used for electric demand peak shaving.

DE Interconnection under California's Rule 21
Determine whether there are any outstanding technical issues in Rule 21 that might interfere with the types of DE installations envisioned for this study.

Effects of DE Resources on the Power Distribution System
Identify, for near- and long-term DE trajectories, potential technical issues with interconnecting DE resources to the electric grid.

Circuit Flicker Analysis with DE
Examine the effects associated with the starting and stopping and system output fluctuations of the proposed DE system installations on circuit voltage flicker.

DE Availability/Probability
Illustrate the overall probability that the proposed DE systems will be available to provide load support on the electric grid when most needed.

Cost Sensitivity

Identify installation costs required to achieve successful customer adoption of advanced energy technologies and illustrate reductions in customer adoption due to higher prices.

Gas and Electricity Inflation
Provide an account of gas and electricity rate changes between 2004 and 2005 and illustrate economic sensitivity to fluctuations in gas and electricity prices.

CIRCUIT MODELING AND METHODOLOGY

Circuit Assessments and Selections

Section Objective: Strategically select two circuits for evaluation that are nearing their capacity, are conducive to advanced energy technologies, and are somewhat representative of typical SCE circuits serving the region.

The first step in this program was to select the electric distribution circuits that would be utilized for the assessment. High-voltage electricity transmission lines deliver electricity to substations, which lower voltage, provide protection and redundancy, and deliver electricity to businesses and homes via individual circuits. Each substation may have from a few to over 20 circuits.

The following assessment was conducted to choose circuits in the host utility territory for analysis. The assessment process was completed in three stages that narrowed the selections from eight circuits to four and finally two, as summarized below:

1. Preliminary Assessment (reviewed seven substations and selected eight circuits).
2. Refined Assessment (narrowed to four circuits).
3. Final Assessment (narrowed to two circuits).

Preliminary Assessments (seven substations and eight Circuits)

SCE identified seven substations in their service territory that could benefit from peak load reduction. The substations were limited to those with radial circuits that may experience power quality issues as a result of load growth.[ii] SCE then provided circuit single-line diagrams overlaid on county maps to help identify the nature of the customers served. GTI and SCE reviewed the drawings and selected eight circuits from the seven substations, for further review. Four of the eight circuits selected serve rural areas and the other four serve more urbanized suburbs of Los Angeles. The following criteria were used to make the preliminary assessment:

- Circuits with planned upgrades, or upgrades being considered, to accommodate load growth.
- Circuits representative of many other circuits in SCE's territory.
- Circuits with customers that may help SCE meet renewable energy goals.

Refined Assessment (Four Circuits)

For the refined assessment, the utility provided customer profile databases that included electrical usage information for customers on all of the circuits associated with each of the substations. The databases were used to identify customer's electrical needs and to determine their locations on the circuits.

The eight circuits selected in the preliminary assessment were representative of many circuits in the utility territory and provided numerous opportunities for peak load reduction using distributed energy, energy-efficiency, and renewable energy. To reduce the number of potential circuits from eight to four, GTI acquired specific customer load data for the selected circuits and selected:

- Circuits with many customers having loads greater than 100 kW.
- Circuits with diverse customer bases.
- Circuits with geographical diversity.

Final Assessment (Two circuits)

Using the data that the utility provided, GTI and the utility focused on the four circuits from the refined assessment and toured the communities via car to become familiar with the circuitry layouts and locations of major customer loads.

With detailed load data, and a detailed understanding of the circuit layouts, the project steering committee was then consulted to select the final two circuits for the project case studies. The committee selected two circuits identified with fictitious names (for non-disclosure purposes) as Justice and Prosper on the Lincoln and Washington substations, respectively. These circuits offered a wide variety of customers and were representative of circuits that serve both suburban and rural areas in the utility service territory. Combined, the circuits served 36 customers with peak electric loads greater than 100 kW. Appendix A summarizes each of the circuits on the substations and lists the customers with annual demands greater than 100 kW.

Substation Details

The Lincoln substation supplies power to 14 radial circuits that are interconnected to allow load-sharing among them. Despite load sharing capability, load relief is still desirable on the circuits because of the extreme growth in the area. Circuitry cabling for Lincoln is mostly buried, which can lead to higher substation upgrade costs.

The Washington substation supplies power to 18 radial circuits. The circuits on Washington are also interconnected, but the circuitry cabling is mostly above ground.

Circuit Details

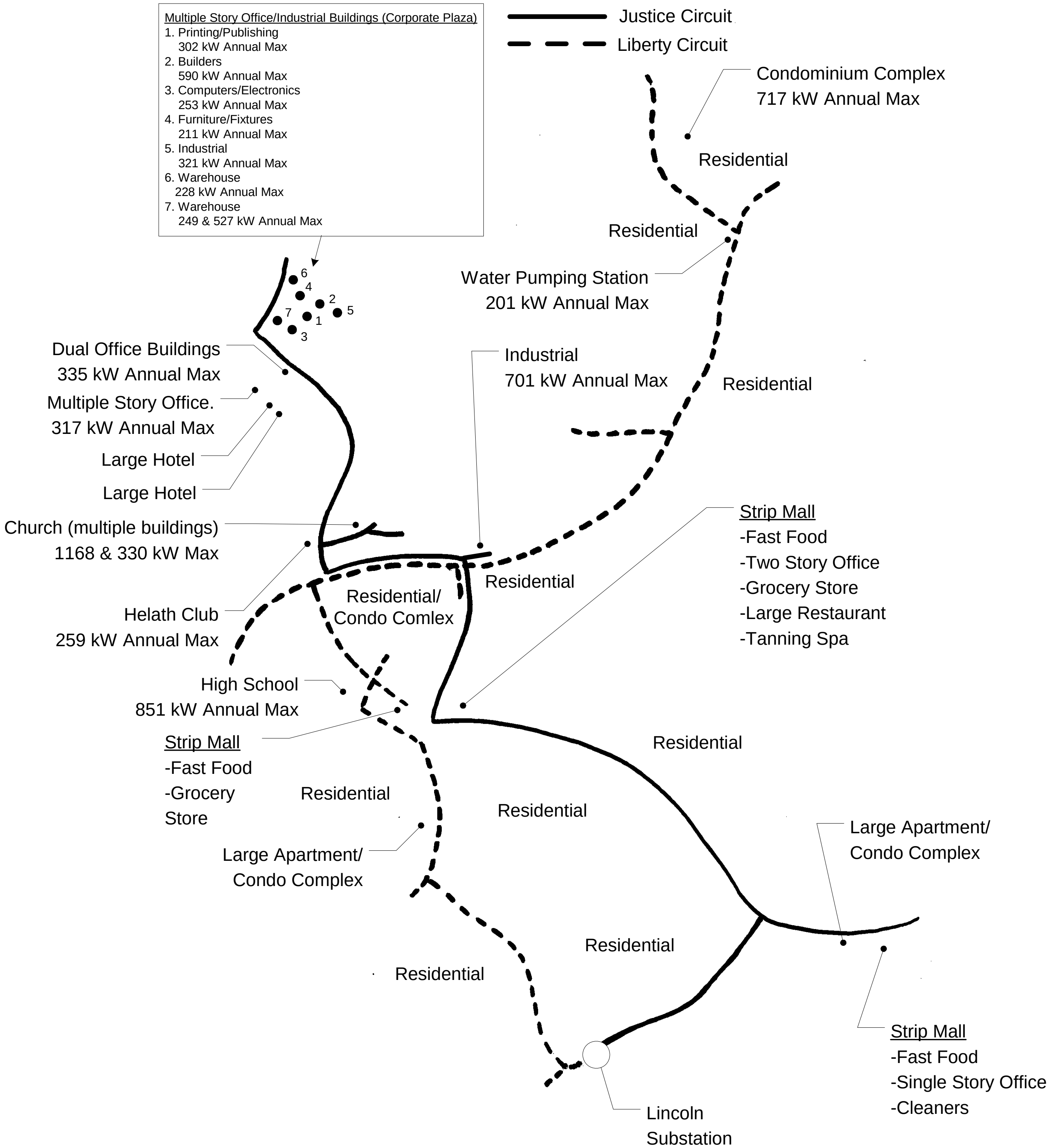
The Justice circuit on the Lincoln substation was selected primarily because it has diverse and numerous electric loads that are large enough to support economic deployment of DG. Several of the customers also have heat loads that might present good CHP applications. The Justice circuit serves a typical suburban community with a significant portion of residential electric loads and clustered commercial loads (strip malls, corporate plazas, industrial parks, etc).

The Justice circuit has 21 customer loads greater than 100 kW, including several office/light industrial buildings, a health club, and hotels (See Table 1 and Figure 2). The circuit will be overloaded if the total customer load exceeds 13 MW. SCE was concerned that the expected load growth would overload the circuit during high demand periods in the future. The estimated load growth on the circuit in the next five years is 1.3%/year.

Table 1 – Justice Circuit Customer Loads >100kW

Customer	Annual Max kW	Annual kWH
Church	1168	3,157,080
Industry	701	1,292,370
Builders	590	1,835,805
Warehouse	527	1,589,147
Dual Office Buildings	335	363,206
Church	330	1,120,789
Industrial	321	965,315
Multiple Story Office	317	1,029,996
Printing/Publishing	302	810,195
Health Club	259	1,191,244
Computers/Electronics	253	525,500
Warehouse	249	1,269,870
Warehouse	228	772,143
Furniture/Fixtures	211	466,800
Nonmetallic Minerals & Prods	198	346,052
Chemical & Allied Products	197	621,310
All Other Commercial	192	352,680
Hotels & Motels	157	193,598
All Other Commercial	148	333,360
Other Warehouses	134	3,600
Other Warehouses	102	155,220

Figure 2 –Justice Circuit Map



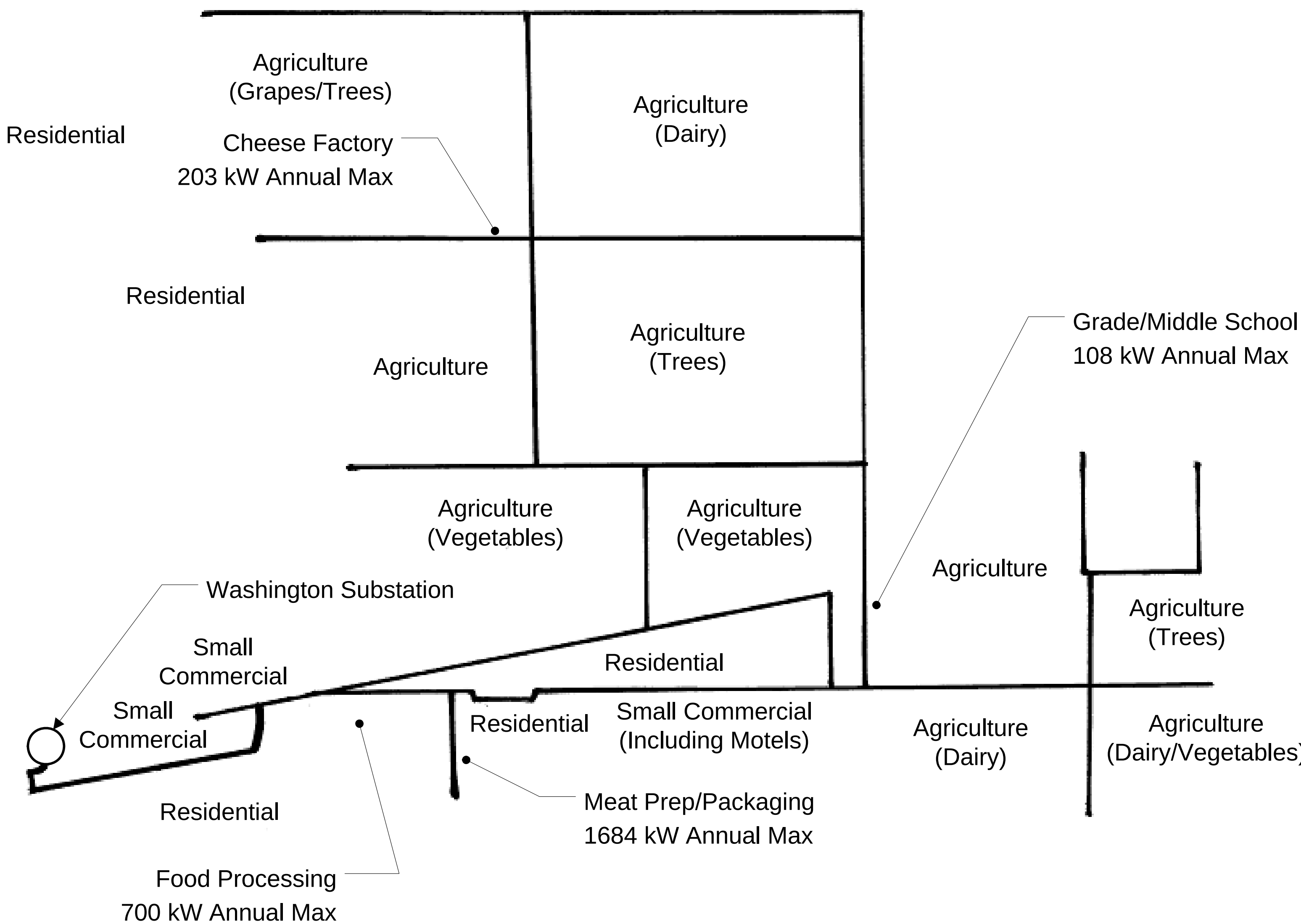
The Prosper circuit serves a fairly typical rural California farming community that offers great potential for renewable energy applications. Many of the customers with facilities for confined animals, meatpacking, and food processing potentially discard large quantities of biological waste. The waste may include animal manure, slaughterhouse remains, unused fruit and vegetable parts (seeds, skins, etc), and dairy farm wastewater. These biological wastes can be decomposed via anaerobic digestion, which would eliminate off-gas air pollution and environmental odor while producing methane, a potential energy source.[9]

The Prosper circuit has 15 customer loads greater than 100 kW, including a meat preparation and storage facility, food processing facility, cheese factory, small school, small commercial buildings, and many dairy and other agricultural farms (See Table 2 and Figure 3). The capacity of the circuit is 8 MW. The estimated load growth on the circuit in the next five years is 1.6%/year.

Table 2 – Prosper Circuit Customer Loads >100 kW

Customer	Annual Max kW	Annual kWH
Meat Prep/Packaging	1684	9,249,380
Food Processing	700	1,975,625
Creamery	292	1,075,598
Cheese Factory	203	385,999
Agriculture	182	27,648
Agriculture	182	495,971
Agriculture	159	450,176
Food Stores/Refrig Warehouse	151	600,298
Agriculture	124	160,920
Agriculture	122	240,350
Agriculture	110	509,800
Agriculture	109	426,141
Schools	108	183,280
All Other Commercial	106	250,400
Agriculture	104	487,920

Figure 3 – Prosper Circuit Map



Methodology

Section Objective: Define the technical approach and key assumptions used to model the circuit load profiles and the circuit impact analysis; key assumptions include technologies and cost, existing market incentives, and expected customer adoption of technologies.

Building Energy Modeling

Building Energy Analyzer (BEA) computer energy modeling was used to generate hourly loads for each non-residential customer on each of the circuits.[iii] The hourly loads for the individual buildings were then summed to produce a model of the hourly circuit loads. Circuit load growth rate estimates, supplied by the utility, were used to project future load levels. BEA consists of hour-by-hour computer simulation models for various building types, heat and power generation equipment, and HVAC equipment. Within the BEA models, equipment (e.g. lighting, HVAC, etc.) and building parameters (e.g. wall material, window designs, roofing, etc.), energy rates, and geographical weather data can be defined for specific applications.

BEA forecasts and reports annual hour-by-hour heat and power loads along with hour-by-hour fuel requirements. GTI refined the software to allow aggregation of multiple building loads for utility circuit and substation load analyses. The software was also refined to optimize generator sizes and absorption cooling equipment capacities for specific building applications.

BEA uses weather data from the typical meteorological year (TMY2) data sets derived from the 1961-1990 National Solar Radiation Data Base (NSRDB).[10] The circuit models generated from the 8760 (24 hours per day 365 days per year = 8,760 hours) building model data streams are typical for weather during the TMY2 time span. Hour-by-hour weather data for 2004 could have been used in BEA in place of the TMY2 data, thereby resulting in a "2004 circuit model." However, the timeline of this study extends ten years into the future. TMY2 data, which spans 29 years, represents average and future conditions better than weather data for one specific year (2004).

Circuit load data provided by SCE are specific to 2004, and thus were used only to gauge the profile accuracy of the typical circuit models. Annual weather variations between 2004 and TMY2 were examined and found to be small, but probably contributed to some load mismatch between the two circuit curves.

Circuit Modeling- Baseline/Future

The baseline models reflect the current condition of the circuits that, as previously indicated, may require capacity expansion unless alternative energy technologies are applied. The future circuit models apply load growth expected over the next ten years to the baseline models.

Peak energy use and monthly energy use were available for all of the buildings and the hourly load data were available for the larger loads and for the circuit as a whole. These data were used to calibrate the BEA models against actual utility circuit loads.[iv] The most effective calibration factors were found to be the HVAC efficiency, the lighting loads, and efficiency, and process load schedules. The calibration was especially important for the Justice circuit because its building inventory was significantly newer than the baseline building characteristics used initially. In particular, the HVAC systems were more efficient, which, in turn, changed the characteristics of the optimal DE system selected for each building.

Circuit Modeling- Alternatives

The objective of alternative circuit modeling (circuit impact modeling) was to determine whether advanced energy technologies are economically viable alternatives to expanding distribution circuit capacity. The circuit impact models for this study reflect hypothetical circuit conditions where DE, EE, and PV technologies have successfully penetrated the market and have been implemented to reduce load on the utility grid. Five circuit impact scenarios were analyzed for each circuit, based on an extensive list of assumptions that the project steering committee evaluated and agreed upon. These assumptions are listed in Appendix B. The five circuit impact scenarios are Customer-Installed DE, Utility-Installed DE, EE, PV, and one scenario with Customer-Installed DE, EE, and PV combined.

The following sections summarize the key issues and assumptions that affect payback periods and market penetration rates for DE, EE, and PV technologies.

Utility Rates

Political interests, local climate, and local sources of electricity supply are all reflected in the utility rates. The political interests, such as renewable portfolio standards and emissions standards determine whether the rate structures are favorable to DE and what emission control technology is required. The meteorological climate determines the relative importance of the summer and winter peaks and the magnitude of any space-conditioning loads that might be coincident with the peak loads. For SCE, competing generation sources are limited, and much of the electricity is generated using premium fuels (e.g. natural gas). Both of these factors increase the retail cost of electricity. Moreover, the California summer cooling needs have led to a rate structure with both on-peak and mid-peak period definitions; so that off-peak hours are limited to only nine hours per weekday in the summer. The off-peak hours are increased to 11 hours per weekday in the winter.

SCE's fuel sources are 14% coal, 20% nuclear, 3% large hydroelectric, 44% natural gas, and 19% renewables[11], and the California Public Utility Commission mandates a fundamental revenue decoupling mechanism in their rate structure. Revenue decoupling breaks the link between the utility's sales volume and its revenues and is intended to remove any disincentive for energy conservation while providing financial stability for the utility.[12] Customers pay from $0.07/kWh to $0.15/kWh, depending on the season and the time of use. These customers also pay summer demand charges up to $17.55/kW/month (See Appendix B for details).

Customer-Installed Distributed Energy Technologies (DE)

DE Emissions Limitations

The State of California has set stringent emissions limitations for all new emission sources. New source emitters must apply for emissions permits through either the local air quality management district (AQMD) or the California Air Regulatory Board (CARB). Specific requirements are defined in Appendix C. Emissions caps were last set in 2003 and will be lowered again in 2007.[13] Therefore, for this study, it was assumed that DE developers would invest in equipment that would meet the 2007 caps. The 2007 caps are based on the best available control technology (BACT) capabilities and are listed below.

Oxides of nitrogen (NOx):	0.07 lb/MW-hr
Carbon monoxide (CO):	0.10 lb/MW-hr
Volatile organic compounds (VOCs):	0.02 lb/MW-hr

Particulate matter (PM):	An emissions limit corresponding to natural gas with fuel sulfur content of no more than one grain per 100 SCF

DE systems that use CHP may take a credit to meet the above emission standard. For each 3.4 million British Thermal Units (BTU) of heat recovered, one megawatt-hour (MW-hr) is deducted from the total generation. To take this deduction credit, the following must apply:

- DE systems are sold with CHP technology integrated into a standardized package by the applicant; and
- DE systems achieve a minimum efficiency of 60% (useful energy out/fuel in) in the conversion of the energy in the fossil fuel to electricity and process heat. The efficiency determination is based on 100% load.

DE Incentives

Incentives are offered to DE developers through a statewide program administered by California's four investor-owned utilities under the auspices of the California Public Utilities Commission (CPUC).

The Self-Generation Incentive Program[14] provides a financial incentive for installing new qualifying self-generation equipment that meets all or a portion of the electric energy needs of a facility. The program provides a one-time incentive payment to help reduce the cost of installing self-generation equipment. The incentive levels for four categories of self-generation technologies are described in Table 3.

Table 3 – CPUC Self Generation Incentives for DER

Incentive Levels	Incentive Offered ($/Watt)	Maximum % of Eligible Project Cost	Minimum System Size	Maximum System Size	Incentive Payment Maximum System Size	Eligible Technologies
Level 1	$4.50/W	50%	30 kW	1.5 MW	1.0 MW	• Photovoltaics • Fuel cells opereating on renewable fuel • Wind turbines
Level 2	$2.50/W	40%	None	1.5 MW	1.0 MW	• Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3-R	$1.50/W	40%	None	1.5 MW	1.0 MW	• Micro-turbines, IC Engines, and small GTs operating on renewable fuel
Level 3-N	$1.00/W	30%	None	1.5 MW	1.0 MW	• Micro-turbines, IC Engines, and small GTs operating on non-renewable fuel, utilizing waste heat recoveryand meeting the reliability criteria

In addition to the self-generation incentive, DE installations are exempt from the otherwise applicable standby and generation reservation charges until June 1, 2011. However, at a minimum, the DE must be:

- Operated in a combined heat and power application
- Powered by any fuel other than diesel

- 5 MW or smaller
- Comply with the applicable best available control technology as determined by the air pollution control district or air quality management district in which they are located.

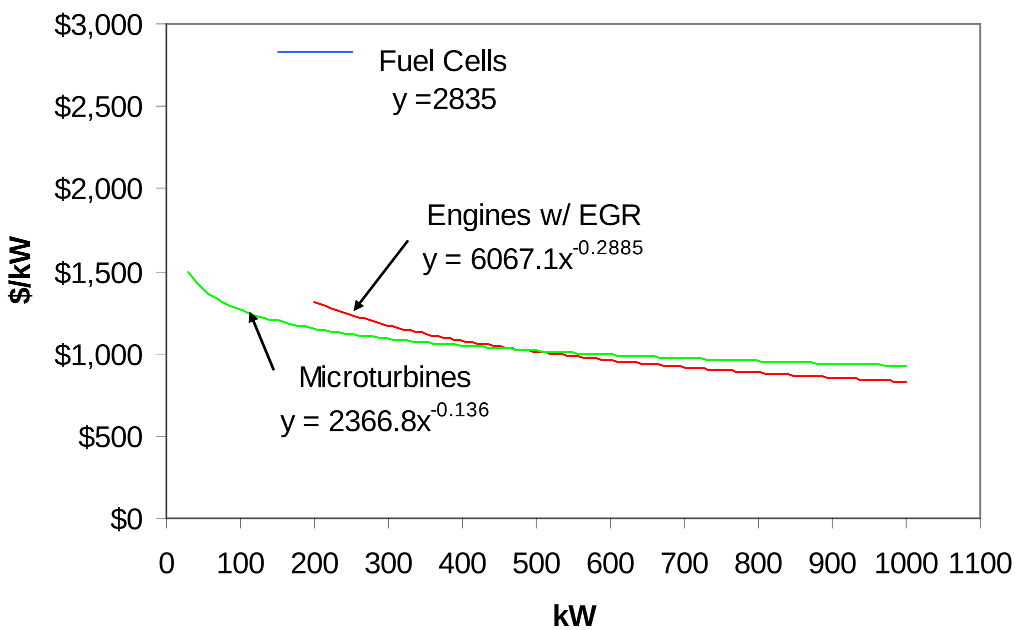
SCE may further offer an incentive to customers for physically assured DE through a benefit-sharing request for proposals (RFP). However, as of December 2005, SCE had not formally released the RFP.[v]

DE Technologies and Cost

The analyses considered a portfolio of DE technologies, including engines, microturbines, gas turbines, and fuel cells, as listed in Appendix B. An assessment to determine the best technologies to apply to the study was made for two separate power ranges, based on the cost curves shown in Figure 4. The curves reflect a 30% reduction to the prices that are defined in Appendix B due to the CPUC Self Generation Incentive Program (level 3-N), identified in Table 3.

Internal combustion (IC) engines encompass both rich- and lean-burning machines. Rich-burn engines are generally more costly than lean-burn engines. However, they require 3-way catalyst emissions controls that are less costly than the EGR or SCR systems used on lean-burn engines. One curve was developed to represent the two types of engines combined with their appropriate emissions control systems. The curves do not include cost for absorption cooling technology.

Figure 4 –Installed Cost after Incentives for DE with Heat Recovery and Emissions Control



The following technology selection rules for this study were made, based on Figure 4:

- Microturbines are the DE technology of choice for applications less than 480 kW. Because engines require costly emissions controls (i.e. BACT) in California, their installed costs are higher than microturbines up to roughly 480 kW.
- Even the most cost-effective fuel cells (i.e. phosphoric acid) are not economically competitive.
- Engines with BACT Emissions Controls are the DE technology of choice for applications 480 kW to at least 5 MW. Engines retrofitted with emissions controls offer better economics than microturbines beyond 480 kW. Additionally, engines are generally more economical than gas turbines for most applications of self-generating electricity up to 5 MW and beyond. However, gas turbines become more feasible when steam is required and base-loading for long periods of time is desirable. For this study, gas turbines were not modeled.

DE Sizing and Configurations

Microturbines and engines were sized and modeled in configurations that offered the best time-discounted payback periods.[vi] The configurations considered included:

- Combined Heat and Power (CHP) – heat recovery to domestic hot water, space heating, and absorption cooling (not options for utility-installed systems). Cost was added per Appendix B when absorption cooling technology was applied.
- Full time operation or operation during utility peak pricing periods only.
- Facility electric demand load tracking.

DE Customer Adoption

Customer adoption, or market penetration rate, is defined in this study as the percentage of customers that install a specific energy technology on a given circuit across the 10-year span of the study. Market penetration rates for DE were used to quantify load relief on the circuits. The rates depend on the time-discounted payback, the number of years required for the load-reduction savings to recoup the first-cost investment in the technology, and O&M cost, considering the cost of money (i.e. interest rate, discount rate, etc – See Appendix B). The quicker the costs are recovered, the higher the penetration rate. Table 4 was developed, based on National Energy Modeling System (NEMS) reports published by DOE.[15,16]

A draft CHP market assessment submitted to the California Energy Commission reports that reciprocating engine systems, the dominant technology for installations smaller than 5 MW, are unable to meet the proposed California Air Regulatory Board 2007 emissions requirements until 2010. Consequently, this report concludes that there would be no market penetration in Southern California until 2010 for systems less than 20 MW.[17] However, as described previously, the proposed 2007 emissions requirements also include an explicit accounting for the usable thermal energy output in a CHP system. When this is taken into account, the best available technology in 2005 is able to meet the 2007 requirements. Another draft submitted to the CEC shows 15% of the DG market in southern California met by gas-fired reciprocating engines (they show half the market met by gas turbines because their definition of DG goes up to 50 MW).[18]

Table 4 – Customer-Installed-DE Market Penetration Rates

Discounted Paybacks Duration (yrs)	Market Penetration Industrial Acceptance Rate	Market Penetration Commercial Acceptance Rate	Market Penetration Institutional Acceptance Rate
0	100.00%	100.00%	100.00%
1	91.00%	97.00%	100.00%
2	71.50%	92.00%	99.00%
3	51.00%	83.00%	97.50%
4	32.00%	68.00%	95.00%
5	18.50%	49.00%	91.00%
6	11.00%	32.00%	86.00%
7	6.50%	19.20%	79.00%
8	4.00%	11.50%	69.00%
9	2.13%	7.00%	57.00%
10	0.88%	3.00%	43.00%
11	0.25%	1.00%	30.00%
12	0.00%	0.00%	18.00%
13	0.00%	0.00%	10.00%
14	0.00%	0.00%	5.00%
15	0.00%	0.00%	2.00%
16	0.00%	0.00%	1.00%
17	0.00%	0.00%	0.00%
18	0.00%	0.00%	0.00%
19	0.00%	0.00%	0.00%
20	0.00%	0.00%	0.00%

Accounting for DE Outages

Based on operational reliability data (mean time between forced DE outages) collected by Energy and Environmental Analysis Inc,[19] microturbines and engines can fail, on average, up to twelve times per year, depending on run time and technology. In recognition of that potential economic burden, it was considered appropriate to account for the cost of DE downtime.

SCE's rate schedules are comprised of energy ($/kWh) and demand ($/kW) charges, as summarized in Appendix B. The demand charge has two components; the coincidental (time-related) TOU (Time-of-use) demand charge and the non-coincidental facilities demand charge. The coincidental TOU demand is based on the highest monthly power demand, and the charges vary by season and peak period. The non-coincidental facilities demand is based on the highest peak power demand during the current billing month and the past 11 billing months, whether or not that peak occurred during a peak period (i.e. the highest demand can happen at any time – 24/7). To account for the cost of DE downtime, a standby charge was implemented in the analysis, despite the fact that SCE currently waives standby charges. The standby charge was set at the facility demand charge, but was proportionally reduced for cases where multiple DE machines were modeled for facility generation. For example, if two 500 kW machines were used to generate 1000 kW, the standby charge was set at one half of the facility demand charge. This model forces the facility to pay by month, at a level dependent upon the DE generator size, for its potential to fail.

Utility-Installed Distributed Energy Technologies

A utility may place distributed generation (DG) equipment at strategic locations on the grid, such as at substations that are capacity constrained or in locations that are constrained by the transmission or distribution line capacity serving that area.

The utility would defer the circuit upgrade cost and also avoid paying the marginal cost of power that would otherwise have been used to supply this peak hour energy. Marginal costs at these peak hours can be more than 20 times greater than average wholesale electricity costs.[5] Also, this type of DG installation does not affect utility revenues from retail power sales. If the DG machines are mounted on a transportable platform, they can be used on successive circuits to delay circuit upgrade costs, matching the growth in circuit capacity more closely with the growth in circuit load, and extending the useful life of the DG equipment.[20] Such transportable engines are often leased if that cost is less than the annualized cost of owning the equipment. Unfortunately, the higher overall efficiencies of CHP systems are rarely possible for the substation location because there will seldom be a corresponding thermal load.

Technologies Considered

Microturbines and engines, with the same emissions limitations as customer-installed DE, were considered for utility-installed DG. However, because the systems were not configured for CHP, the potential for incentives was restricted.

Portable power and energy storage technologies were added to the portfolio of technologies considered for analysis of utility-installed DG. Both technologies are clearly suited for utility use, because they are inherently ideal for capacity support during high demands that occur for relatively short periods of time (e.g. less than 300 hours per year).

Portable power DG systems offer great flexibility, as described above, however they are typically Diesel-fueled. This is primarily because natural gas machines often require costly pipelines and metering stations. Due to emissions constraints, Diesel-fueled system runtime is limited to less than 200 hours per year for emergency purposes only (i.e. grid power is unavailable). As such, utilities in California are restricted from using Diesel generation for grid support.

Energy storage technologies can be used by utilities for load management by discharging when supplemental power is needed and charging when it is not. Energy storage technologies that were considered for this study included those characterized in a study published by the DOE Energy Storage Program and Sandia National Laboratories.[21] Key participants in the Sandia study, including DOE and Distributed Utility Associates, subsequently prepared an analysis suggesting that lead-acid battery systems (LABS) are the most appropriate energy storage technology for this study (reference Appendix D for the analysis). The estimated installed cost for LABS is $1,800/kW, based on a five-hour discharge period and 12-year life span.

Energy-Efficiency Technologies

EE Incentives

Incentives are offered to energy efficient equipment users through a statewide CPUC program that offers cash incentives for the purchase of technology that improves the efficiency of energy usage at the customer's site.[22] Qualifying equipment must retrofit, replace, or upgrade old equipment with new, energy-efficient technologies. Self-generation customers are eligible, based on the percentage of energy the utility provides. Cash incentives are available to nonresidential customers (<500 kW) for the purchase of qualifying lighting, refrigeration, air conditioning, food service, agricultural, irrigation, and gas equipment. Cash incentives are limited to $200,000 per customer, per fuel, per year, up to $300,000 total. Commercial, industrial, and agricultural customers (>500 kW) that pay the public goods charge on their utility bills, can receive cash incentives based on energy savings that are verified either through calculated or measured approaches. Almost any energy-efficiency project involving equipment replacement or retrofit that results in energy savings that can be verified in accordance with the program requirements is eligible. Cash incentives are limited to $300,000 per customer site.

Incentive rates vary based on measured categories as shown in Table 5. The kWh savings from the EE technologies were used for each of the building models to determine the amount of incentives to apply for economic calculations.[vii]

Table 5 - EE Incentive Rates

Measured Category	Incentive Rate
Itemized Incentive	Per item basis
Lighting (Fluorescent, Other Lighting, or Lighting Controls	$0.05 per kWh saved
Motors and Other Equipment	$0.08 per kWh saved
Air Conditioning and Refrigeration (AC&R)	$0.14 per kWh saved
Natural Gas	$1.00 per therm saved

EE Technologies and Cost

A collection of high-performance energy-efficient technologies was applied to the building models. The following energy optimization strategies were implemented:

- T-5/T-8 fluorescent lighting with electronic ballasts (40% less watts/square foot than incandescent).
- Double-pane low-emissive windows (did not apply to dairies and agriculture).
- Light, or reflective roof color, as opposed to dark.
- Variable-speed chillers.
- Variable-speed drives for fans and pumps.
- 10% improvement in agricultural pumping efficiency.[23]
- HVAC systems reduced from 120% to 100% of load (no over sizing).
- Variable air volume control.
- Boiler efficiency improvement from 82% to 85%.

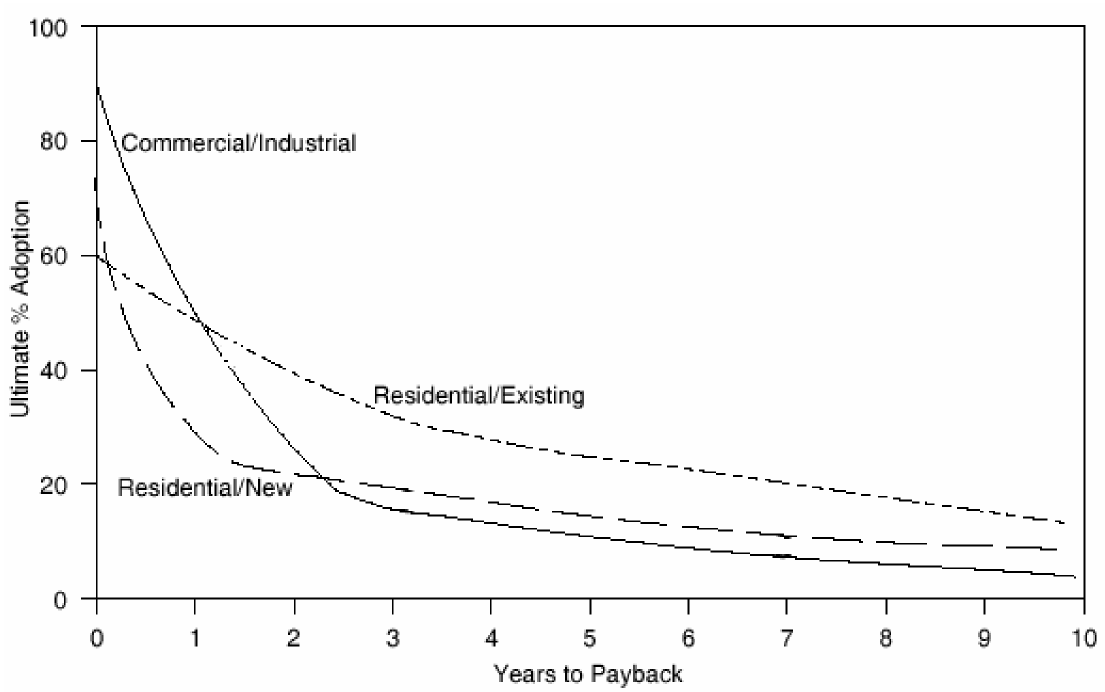
Ground-coupled geothermal heat pumps were considered an energy efficient technology but were not applied to the study. Geothermal heat pumps are cost-effective when they can be used for both heating and cooling loads. The areas of California included in this study have little heating needs.

Application of energy-efficient technologies is difficult to monetize, but they represent common USGBC (U.S. Green Building Council) LEED (Leadership in Energy and Environmental Design) green building strategies. USGBC certified green-building premiums typically cost $3/ft^2 to $5/ft^2 for new construction.[24] The benchmark price for the EE measures was, therefore, set at $4/ft^2 (not including incentives).

EE Customer Adoption

Customer adoption, or penetration rates, used for energy-efficiency technologies are illustrated in Figure 5.[25] Penetration rates are the percentage of customer adoption over the 10-year span of the study.

Figure 5 – Energy-Efficiency Market Penetration Rates



Renewable Energy (RE) Technologies

A renewable energy technology, for the purpose of this study, is defined as a system fueled by one of the following energy sources: solar, wind, or gas derived from biomass, digester gas, or landfill gas. A facility utilizing a renewable fuel may not use more than 25% fossil fuel annually, as determined on a total energy input basis for the calendar year.

RE Incentives

The CPUC's Self-Generation Program offers incentives specific to renewable energy technologies, as previously indicated in Table 3. Additionally, the California Energy Commission (CEC) is offering cash rebates on eligible renewable-energy electric-generating systems through its Emerging Renewables Program.[26] Table 6 lists the rebate levels available as of January 1, 2004 by size category and technology type.

Table 6 – CEC Incentives for Emerging Renewables Program

Technology Type	Size Category	Rebate Offered*
Photovoltaic,	<30 kW	$3.20 per Watt
	=>30 kW	Future Performance Incentive
Solar Thermal Electric Fuel Cells using a renewable fuel**	<30 kW	$3.60 per Watt
Solar Thermal Electric Fuel Cells using a renewable fuel	=>30 kW	Future Performance Incentive
Wind	First 7.5 kW	$2.10 per Watt
	Increments above 7.5 kW up to 30 kW	$1.10 per Watt
	=> 30 up to 50 kW	Future Performance Incentive

* Rebates for owner installed systems are discounted by 15 percent.
** Fuel cells that operate on non-renewable fuels and are used in combined heat and power applications may be eligible for rebates at a later date when funds from other sources, such as the Self Generation Incentive Program, are no longer available.

CEC is also offering a program called the Dairy Power Production Program (DPPP) that provides two types of assistance for qualifying dairy biogas projects: buy-down grants that cover a percentage of the capital costs of the proposed biogas system, and incentive payments for generated electricity.[27] In general, buy-down grants cover a maximum of 50% of the capital costs of the biogas system based on estimated power production, but not to exceed $2,000 per installed kilowatt of electricity, whichever is less. Electricity generation incentive payments are based on 5.7 cents per kilowatt-hour generated by the dairy biogas system, paid out over a maximum of five years. The total cumulative payments under the incentive payment route are intended (after five years) to equal the amount of funding that would be provided for an equivalently sized digester-to-electricity system under the grant buy-down approach.

RE Technologies and Cost

Renewable energy technologies modeled in this study include photovoltaics (PV) and distributed energy technologies fueled by biomass or digester gas (biopower). The following renewable energy fuels were also considered, but not modeled:

- Wind: There is too little wind potential, based on historical weather data for the study areas.[28]
- Landfill gas: No landfills exist in the study areas.
- Hydro: The geology in the study areas does not support natural hydro power.
- Solar heating: Buildings in the study areas do not require enough heat to justify solar heating.

Photovoltaics:

Photovoltaics, at 10 watts/ft^2, were modeled for panels covering 25% and 50% of the building roof area for Prosper and Justice circuits, respectively.[viii] Additional parameters for PV are listed in Appendix B.

As defined in Appendix B, PV installations cost $9.5/watt. However, the following incentives would apply for PV developers in California:

- Self-Generation -$4.5/watt (See Table 3)
- Emerging Renewables -$3.2/watt (See Table 6)

The benchmark PV installation price is therefore $1,800/kW, or $9.5/W minus $4.5/W minus $3.2/W, which equals $1.8/W.

Dairy Power Production:

Based on current emissions estimates, dairy farms are a significant source category of reactive organic gas emissions.[29] In this part of California, local air pollution control and air quality management districts must soon adopt rules that require large confined animal facilities to submit emissions mitigation plans. Dairy farms with 1,000 cows or more trigger the requirement for a mitigation plan. According to the California Environmental Protection Agency Air Resources Board (CARB), almost 85% of the dairy farms within the county where the Prosper circuit is located have 1,000 milking cows or more.

Therefore, for the purpose of this analysis, it was assumed that the dairy facilities would install digesters, which have process hot water demands for digester sludge heating that could be met in part with hot water recovered from CHP systems. The digesters were assumed to produce enough biogas methane, based on 100 W/cow, to eliminate 50% of the fuel cost for power generation. Furthermore, it was assumed that 50% of the sludge-heating requirements would be met by the CHP systems. Dairy power developers are confronted with a premium on such projects, as they involve additional equipment like digesters. Table 7 is a list of CEC approved Dairy Power Production projects as of May 2003, including the total estimated cost, type of digesters, and total estimated electricity.[27]

Table 7 – Costs and Characteristics of CEC Approved DPPP Projects

Dairy ID Number	Total Estimated Cost $/kW installed	Type of Digester	Total Estimated kW Installed
201	$3,017	Cov'd lagoon	120
204	$4,298	Cov'd lagoon	300
207	$1,811	Cov'd lagoon	75
221	$4,831	Cov'd lagoon	160
222	$3668	Cov'd lagoon	280
225	$1,469	Plug flow	260
226	$3,764	Plug flow	130
230	$3,281	Plug flow	160
232	$2,500	Cov'd lagoon	30
238	$1,530	Cov'd lagoon	150

Dairies number 207, 225, and 238 have considerably lower estimated costs because the facilities already had digesters before power generation was installed. For this study, it was assumed that none of the facilities on the Prosper circuit currently have digesters in place. Therefore, dairies 207, 225, and 238 were discounted. Based on the remaining seven facilities on the list, the following equation was derived to estimate future dairy power project costs in California:

Cost = 5.028(X) + 2775, where X = capacity, in kW

Table 8 lists the same dairy farms along with the corresponding CEC grant funding and payment methods.[27]

Table 8 – CEC Funding for Approved DPPP Projects

Dairy ID Number	CEC Grant Funding Amount ($)	Estimated kW Potential	Payment Method
201	$181,000	120	Buydown
204	$600,000	300	Buydown
207	$67,900	75	Buydown
221	$320,000	160	Buydown
222	$513,553	280	Buydown
225	$190,925	260	Incentive
226	$244,642	130	Buydown
230	$262,449	160	Buydown
232	$37,500	30	Incentive
238	$114,779	150	Buydown
Total	**$2,532,748**	**1,665**	

Again, discounting dairies numbered 207, 225, and 238, the approved grants average $1,830/kW. All of the buy-downs were 50% of the overall dairy power project cost.

RE Customer Adoption

Customer adoption of biopower was based on customer-installed-DE penetration rates, as previously illustrated in Table 4.

Customer adoption of PV was based on energy-efficiency penetration rates, as previously illustrated in Figure 5.

CIRCUIT ANALYSIS RESULTS

Baseline Circuit Analysis

Section Objective: Illustrate the circuit load profile models, based on aggregate TMY2 building models, as compared to the actual 2004 circuit load profiles acquired from SCE.

The baseline models reflect the current condition of the circuits. The future circuit models apply the load growth expected over the next ten years to the baseline models.

Justice Circuit on Lincoln Substation –Baseline Model

Figure 6 shows the actual Justice circuit load duration curve (LDC) and the LDC when the residential electric load, (provided separately by SCE) is removed. The residential load is fairly significant on Justice but was not modeled. The BEA was used to generate building models for

100 non-residential customer facilities on the circuit. Figure 7 shows the Justice circuit model LDC, which is an aggregate of the 100 individual customer loads, compared to the actual LDC without residential load.

Figure 6 – 2004 Justice Load Duration Curves with and without Residential Load

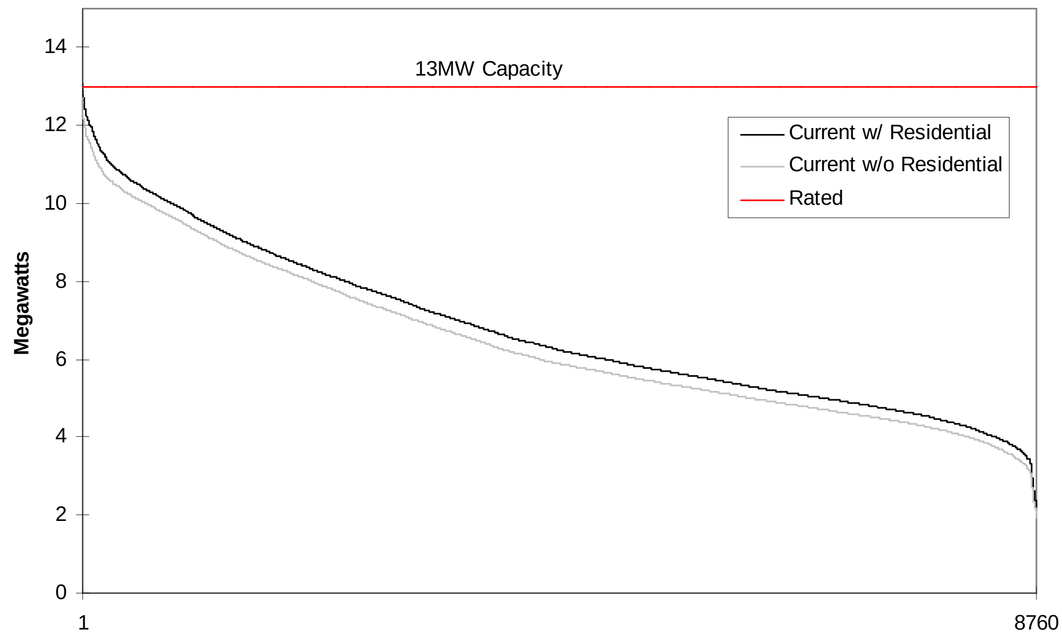
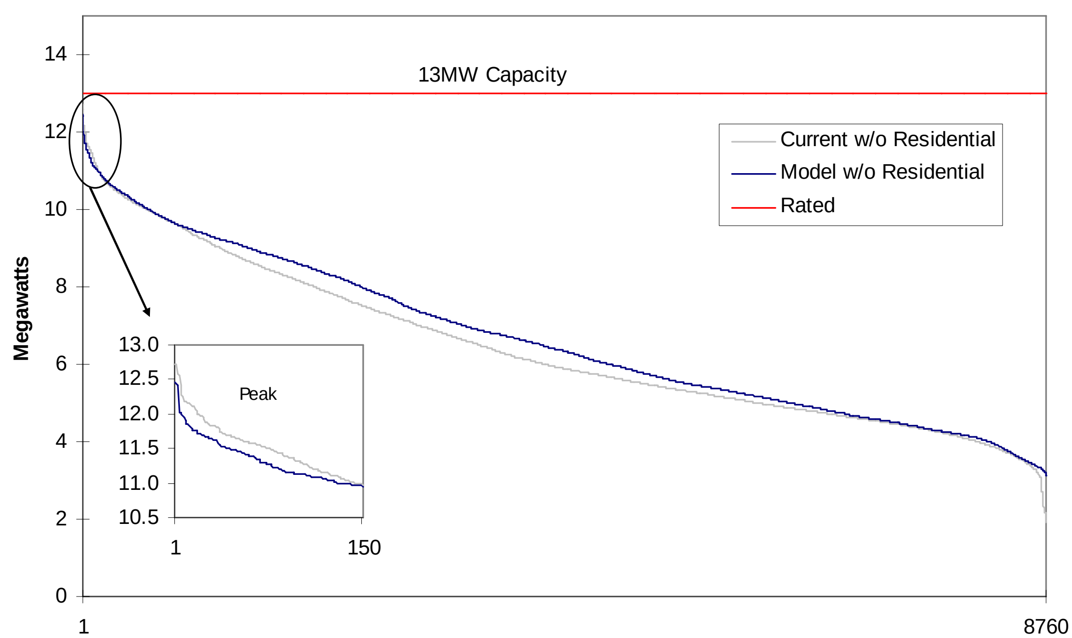


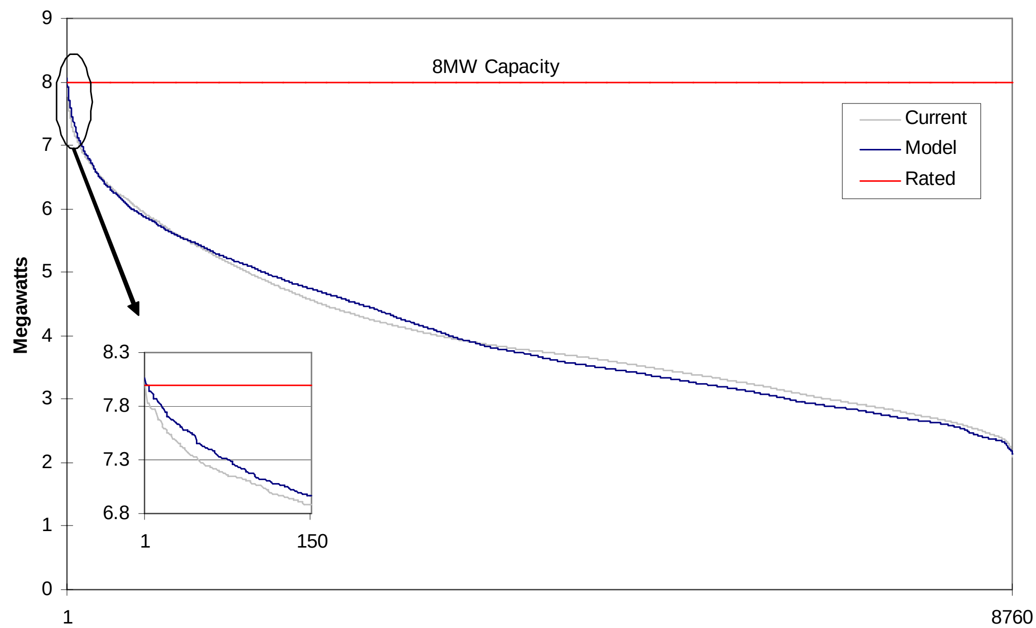
Figure 7 – 2004/TMY2 (Model) Justice Load Duration Curves



Prosper Circuit on Washington Substation – Baseline Model

Figure 8 shows the Prosper circuit model LDC, which is an aggregate of the 103 individual customer loads, compared to the actual LDC. Unlike the residential load on the Justice circuit, the residential load on the Prosper circuit is insignificant. Therefore, residential load was not removed.

Figure 8 – 2004/TMY2 (Model) Prosper Load Duration Curves



Circuit Impact Analyses

Section Objective: Illustrate the impact of DE, EE, and PV technologies on the circuit load profile models given the expected customer adoption of the technologies in the next 10 years.

The circuit impact analysis models reflect circuit conditions after load growth (future circuit models) where DE, EE, and PV technologies have been successfully installed at facilities and utility load has been reduced.

Justice Circuit on Lincoln Substation – CHP Model

Of the 100 customers on the Justice circuit, 13 customers could install CHP systems that would provide enough energy cost savings to pay back their investment in less than ten years. However, using the market penetration curves (Table 4), only three of these customers would install CHP. Figure 9 shows the circuit LDC for the current model and the model after the predicted 10-year load growth of 1.3% per year is applied. It also shows the resulting LDC if three customers install CHP within the 10-year study period. Table 9 is a list of the three customers along with their CHP equipment capacities. The CHP systems were configured to run during mid- and on-peak hours only.

Figure 9 – Justice Circuit Impact Models (CHP, EE and PV)

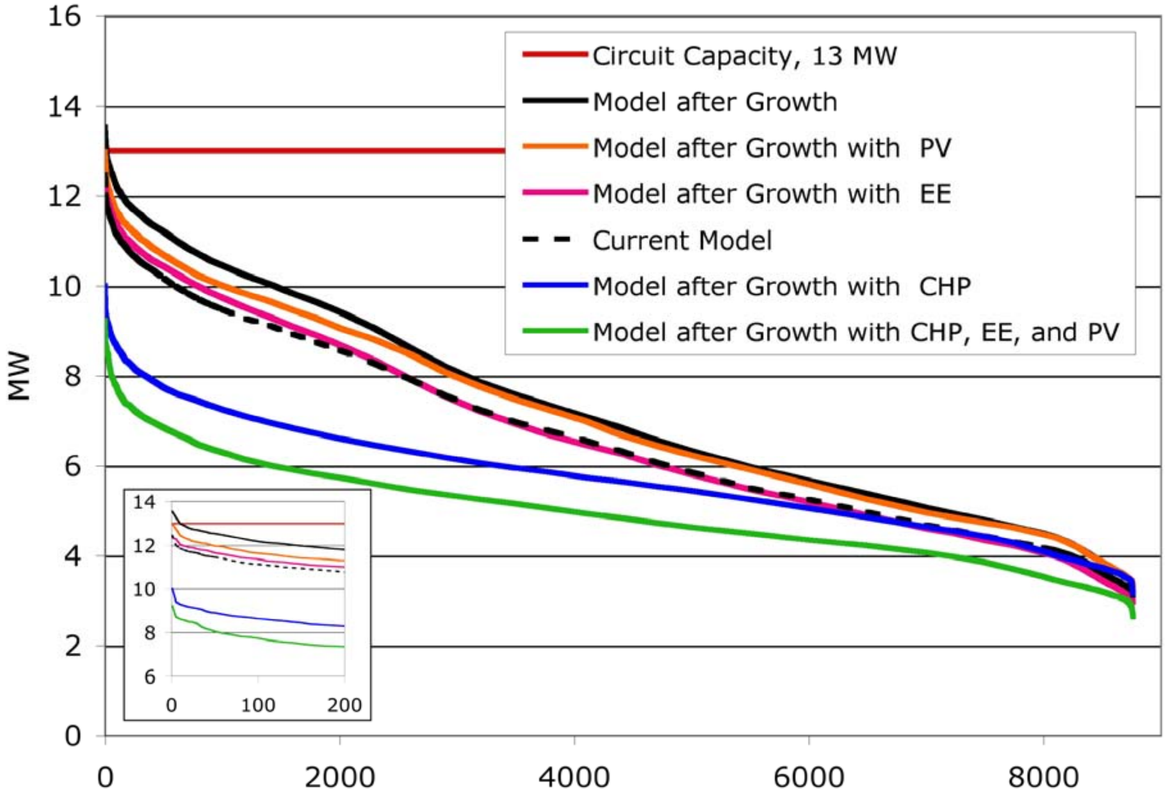


Table 9 – CHP Facilities on Justice Circuit

Facility	Rate	Peak kW	Gen kW	Tons	Absorption	Process MMBtu/hr	Installed $/kW	Annual O&M
Church/School	TOU-8	1,624	600	757	35%	0	$1,300	$21,000
Industrial	TOU-8	3,714	3,000	1,777	55%	0	$800	$106,000
Industrial	Non-TOU	699	600	201	0%	2.336	$1,000	$21,000

Research on all of the customers was done to determine the types of facilities in operation. It was found that two of the facilities may have process hot water demands that probably could be met with hot water recovered from CHP systems. One of the facilities is shown in Table 9 with a process heat demand of 2.336 MMBtu/hr, which is about what a 600 kW generator would provide.

Installing 4.2 MW of CHP at the three facilities reduced the circuit peak demand by 3.53 MW while displacing well over 13 million kWh when compared to the future circuit model. These savings, combined with the offset for purchased fuel, would save the three customers in total over $850,000 annually based on current expenditures.

During the course of the study, SCE transferred a 3,714 kW industrial facility from the Justice circuit to an adjacent circuit nearby. However, for the purpose of this study, it was assumed that the facility was not transferred. That customer can install 3 MW of CHP economically and potentially defer or eliminate the need for a circuit upgrade. As Figure 9 indicates, the demand met by CHP at that facility, along with the two other facilities, could have deferred or eliminated the need for a circuit upgrade or customer transfer.

Justice Circuit on Lincoln Substation – EE Model

Eighty seven of the 100 customers on the circuit could install EE technologies that would provide enough energy cost savings to pay back their investment in less than 10 years. Applying the EE market penetration curves (Figure 5), only 11 of the customers would install EE technologies. Figure 9 also shows the resulting future circuit LDC if 11 customers install EE within the 10-year study period. Table 10 is a list of the 11 customers.

Table 10 – EE Facilities on Justice Circuit

Facility	Rate	Peak kW	EE Installed Cost
Church/School	TOU-8	1,624	$550,000
Hotel	Non-TOU	223	$106,000
Hotel	Non-TOU	196	$90,000
Hotel	Non-TOU	137	$64,000
Industrial	TOU-8	3,714	$1,514,000
Industrial	Non-TOU	699	$282,000
Industrial	Non-TOU	322	$125,000
Office	TOU-8	835	$533,000
Restaurant	Non-TOU	43	$8,000
Restaurant	Non-TOU	35	$6,000
Retail	Non-TOU	349	$261,000

Collectively, EE technologies installed at 11 facilities reduce the peak demand by 1.19 MW and save over 5 million kWh when compared to future circuit load. The energy savings would save the customers, in total, $620,000 annually based on current expenditures.

Figure 9 indicates that the demand met by EE alone at the 11 facilities might be enough, with very little to spare, to eliminate the need for a circuit upgrade.

Justice Circuit on Lincoln Substation – PV Model

PV technologies could be installed at 68 of the 100 customers on the circuit with enough energy cost savings to pay back the investments in 8 to 10 years. However, once again, using the market penetration curves (Figure 5), only four of the customers would install PV technologies. Figure 9 again, shows the resulting LDC if the four customers install PV within the 10-year study period. Table 11 is a list of the four customers and the PV capacities.

Table 11 – PV Facilities on Justice Circuit

Facility	Rate	Peak kW	PV Square Footage	Max kW	PV Installed Cost
Church/School	TOU-8	1,624	82,500	825	$1,485,000
Industrial	Non-TOU	146	8,500	85	$153,000
Retail	Non-TOU	301	14,450	144	$260,000
Supermarket	Non-TOU	109	2,600	26	$47,000

The "Max kW" of the photovoltaic system is the maximum capacity rated at 10W/ft^2 generating conditions.

PV technologies installed at the four facilities reduced the peak demand by 0.56 MW, while the combined annual energy displacement is over 1.5 million kWh when compared to the future circuit load. The energy savings would save the customers in total about $200,000 annually based on current expenditures.

Figure 9 indicates that, although the demand met by PV at the four facilities keeps the circuit demand below 13 MW, PV alone would probably not eliminate the need for a circuit upgrade.

Justice Circuit on Lincoln Substation – CHP, EE and PV Combined

Finally, Figure 9 shows the overall impact of advanced energy technologies on the circuit if each of the customers that projected attractive economics where to install the proposed DE, EE, and PV technologies. If the respective technologies are installed by the customers, 4.3 MW of integrated demand reduction[ix] and over 20 million kWh of load relief, when compared to future circuit load, could be accomplished while saving customers almost $1.7 million annually, based on current expenditures. Successful deployment of DE, EE and PV technologies, installed at reasonable penetration rates over 10 years, could defer the need to upgrade the circuit.

Prosper Circuit on Washington Substation – CHP Model

Of the 103 customers on the Prosper circuit, 13 customers could install CHP systems that would provide enough energy cost savings to pay back their investment in less than 7 years; most are less than 5 years. Using the market penetration curves (Table 4), 11 of the customers would install CHP. Figure 10 shows the LDC for the current circuit model and the circuit model after the predicted 10-year load growth of 1.6% per year is applied. It also shows the resulting future circuit LDC if 11 customers install CHP within the 10-year study period. Table 12 is a list of the 11 customers along with CHP equipment capacities. With the use of methane, the cost to fuel CHP is less than off-peak electricity prices. Therefore the CHP systems for the dairy farms were configured to run full time. All other CHP systems were configured to run during mid- and on-peak times only.

Figure 10 – Prosper Circuit Impact Models (CHP, EE and PV)

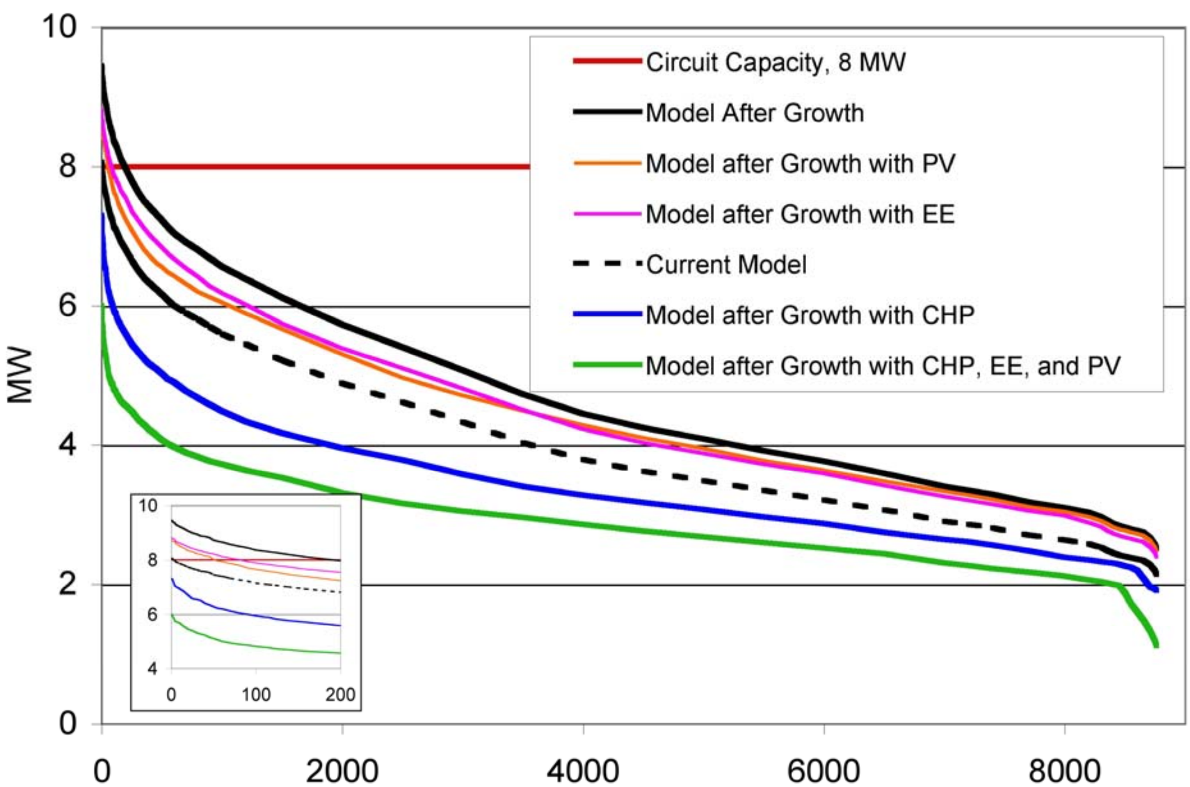


Table 12 – CHP Facilities on Prosper Circuit

Facility	Rate	Peak kW	Gen kW	Tons	Absorption	Process MMBtu/hr	Installed $/kW	Annual O&M
Dairy	TOU	352	360	30	0%	0.7	$2,755	$52,887
Dairy	Non-TOU	28	30	3	0%	0.055	$1,096	$3,921
Dairy	Non-TOU	82	60	8	0%	0.155	$1,247	$11,964
Dairy	TOU	361	360	19	0%	0.5	$2,755	$34,632
Dairy	Non-TOU	128	120	12	0%	0.25	$1,548	$19,686
Dairy	Non-TOU	51	30	6	0%	0.055	$1,096	$6,870
Dairy	Non-TOU	270	300	24	0%	0.6	$2,453	$41,073
Dairy	Non-TOU	110	90	11	0%	0.185	$1,398	$7,536
Industrial	TOU	482	90	97	100%	0	$1,283	$3,035
R-warehouse	Non-TOU	1684	1680	396	60%	0	$712	$46,683
School	Non-TOU	203	60	149	90%	0	$1,356	$1,681

Research on all of the customers was done to determine the types of facilities in operation. Many of the facilities were dairy farms.

The dairy economics based upon California's incipient agricultural emissions regulations, which can be met using a digester system, are extremely favorable to DE. The economics are also favorable for DE when a dairy without a digester (and therefore no additional heating load) is compared to a dairy with a digester (additional heating load) and CHP. However, considering that many of these dairies may be required to install emissions equipment in the near future, the digester-CHP system should be seriously considered.

Installing 3.18 MW of CHP at 11 facilities reduced the circuit peak demand by 2.15 MW while displacing over 11 million kWh when compared to future circuit load. These energy savings, combined with the offset for purchased fuel, would save the customers in total almost $2 million annually, based on current expenditures.

As Figure 10 indicates, the demand met by CHP at the 11 facilities could defer or eliminated the need for a circuit upgrade or customer transfer.

Prosper Circuit on Washington Substation – EE Model

Ninety three of the 103 customers on the Prosper circuit could install EE technologies that would provide enough energy cost savings to pay back their investment in less than 10 years. However, using the EE market penetration curves (Figure 5), only 35 of the customers would install EE technologies. Figure 10 shows the resulting future circuit model if the 35 customers install EE within the 10-year study period. Table 13 is a list of the 35 customers.

Table 13 – EE Facilities on Prosper Circuit

Facility	Rate	Peak kW	EE Installed Cost
Agriculture	Non-TOU	18	$1,038
Agriculture	Non-TOU	245	$12,866
Agriculture	Non-TOU	21	$1,229
Agriculture	Non-TOU	185	$11,978
Agriculture	Non-TOU	123	$7,998
Agriculture	Non-TOU	78	$4,682
Agriculture	Non-TOU	39	$2,150
Agriculture	Non-TOU	32	$1,663
Agriculture	Non-TOU	19	$1,109
Agriculture	Non-TOU	99	$5,923
Agriculture	Non-TOU	54	$3,244
Agriculture	Non-TOU	26	$1,587
Agriculture	Non-TOU	294	$15,751
Agriculture	Non-TOU	40	$4,431
Agriculture	Non-TOU	114	$7,452
Agriculture	Non-TOU	18	$1,948
Agriculture	Non-TOU	48	$2,854
Church	Non-TOU	40	$17,520
Church	Non-TOU	79	$37,837
Dairy	Non-TOU	361	$511,439
Dairy	Non-TOU	128	$305,332
Ag	Non-TOU	22	$1,277
Hotel	Non-TOU	71	$47,649
Industrial	Non-TOU	443	$302,153
Office	Non-TOU	42	$18,841
Fast Rest	Non-TOU	16	$2,509
Retail	Non-TOU	80	$4,386
Retail	Non-TOU	36	$1,976
Retail	Non-TOU	70	$3,879
Retail	Non-TOU	14	$730
Retail	Non-TOU	58	$3,196
Retail	Non-TOU	54	$2,997
Retail	Non-TOU	28	$1,545
School	Non-TOU	203	$112,213
Supermarket	Non-TOU	119	$16,451

EE technologies installed at 35 facilities, combined, could reduce the peak demand by 0.63 MW and save over 2 million kWh when compared to future circuit load and could save the customers in total about $290,000 annually, based on current expenditures.

Figure 10 indicates that the demand met by EE alone at the 35 facilities would probably not eliminate the need for a circuit upgrade.

Prosper Circuit on Washington Substation – PV Model

Of the 103 customers on the circuit, 46 customers could install PV technologies that would provide enough energy cost savings to pay back their investment in 7 to 10 years. Using the market penetration curves (Figure 5), only three of these customers would install PV technologies. Figure 10 also shows the resulting circuit LDC if three customers install PV within the 10-year study period. Table 14 is a list of the three customers and the PV capacities.

Table 14 – PV Facilities on Prosper Circuit

Facility	Rate	Peak kW	PV Square Footage	Max kW	PV Installed Cost
Industrial	TOU	443	21,250	213	$382,500
Industrial	TOU	707	29,768	298	$535,824
R-warehouse	TOU	1,684	62,562	626	$1,126,116

The "Max kW" of the photovoltaic system is the maximum capacity rated at 10W/ft^2 generating conditions.

The combined annual energy displacement from PV technologies installed at the three facilities would be almost 2.3 million kWh and would reduce the peak demand by 0.73 MW when compared to future circuit load. The displacement would save the customers, in total, about $230,000 annually, based on current expenditures.

Figure 10 indicates that the demand met by PV alone at the three facilities would probably not eliminate the need for a circuit upgrade.

Prosper Circuit on Washington Substation – DE, EE and PV Combined

Lastly, Figure 10 shows the overall impact of advanced energy technologies on the circuit if each of the customers that projected attractive economics where to install the proposed DE, EE, and PV technologies. If the respective technologies are installed by the customers, about 3.5 MW of integrated demand reduction[ix] and almost 15.6 million kWh of load relief when compared to future circuit load could be accomplished while saving customers about $2.4 million annually, based on current expenditures. Successful deployment of DE, EE and PV technologies at reasonable penetration rates across 10 years, could defer the need to upgrade the circuit, offsetting the projected 10-year load growth.

Circuit Impact Analyses Summary

Table 15 is a summary of the peak load and kWh reductions when compared to future circuit loads, due to each of the technologies on both circuits, as well as the monetary savings, based on current expenditures. As previously discussed, it is assumed that dairies would install digesters. The digesters would make methane that could be used for CHP fuel, thereby displacing traditional fuel costs. This displacement of purchased fuel result is a negative cost increase, or a cost savings, in Table 15.

Table 15 – Summary of Peak Load Reductions on Justice and Prosper Circuits

Technologies				Total Annual Figures					
Utility Circuit	Energy Tech	Customer Adoption	Total MW Installed	Peak MW Reduction	kWh Reduction	Reduced Electric Bills	Increased Fuel Cost	Change in O&M Costs	Net Reduction in Operating Costs
Justice	DE	3	4.20	3.18	13,420,000	$1,730,000	$733,000	$146,000	$851,000
Prosper	DE	11	3.18	2.15	10,580,000	$1,390,000	-$568,000	$111,000	$1,847,000
Justice	EE	11	NA	1.16	5,130,000	$620,000	NA	NA	$620,000
Prosper	EE	35	NA	0.63	1,520,000	$290,000	NA	NA	$290,000
Justice	PV	4	1.08	0.56	1,550,000	$200,000	NA	NA	$200,000
Prosper	PV	3	2.83	0.73	1,600,000	$230,000	NA	NA	$230,000

Utility Economics

Section Objective: Establish marginal transmission and distribution cost estimates and the economics for customer-owned and utility-owned DE.

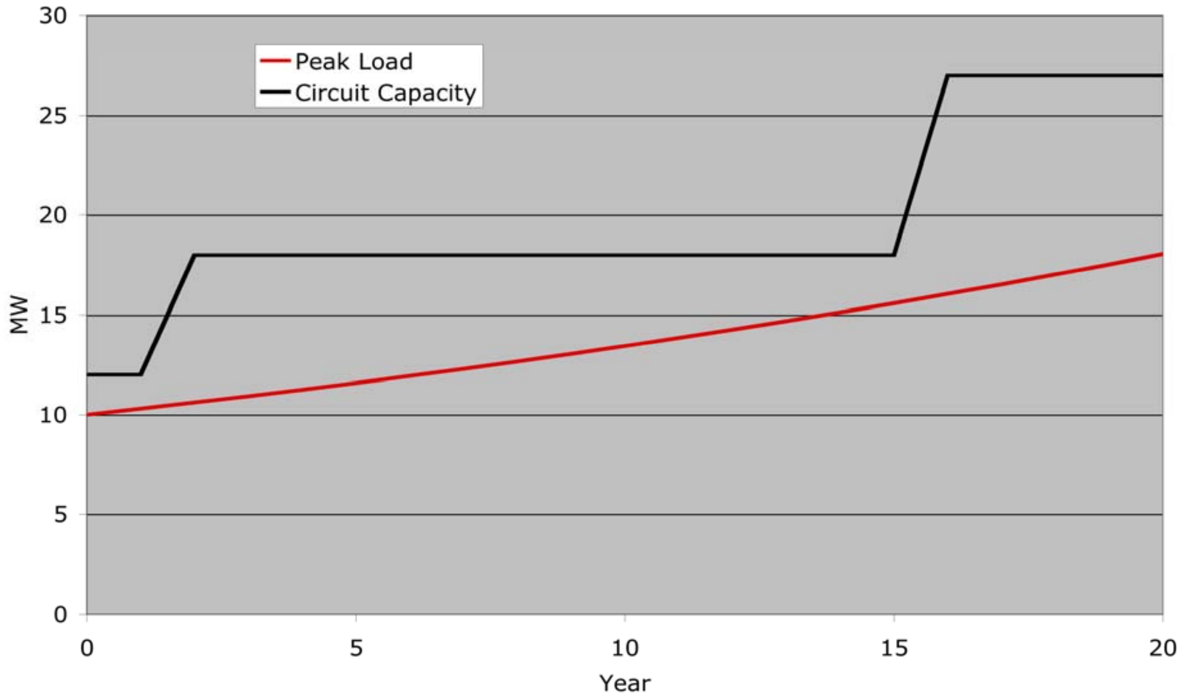
California is pursuing an aggressive CHP, EE and renewables program to reduce peak electric demand, conserve energy, and provide clean local power production. Utilities in California can expect a significant impact on revenue due to continued growth in deployment of these advanced technologies. As the results from this analysis indicate, DE, EE and PV, if only deployed moderately on the SCE circuits, can greatly reduce peak and base-load demands. If a circuit is upgraded to account for load growth, but customers install demand-side technologies, thereby depleting the utility revenue stream, the utility investment becomes stranded.

This study explores the possibility to defer circuit upgrades using customer- or utility-owned DE. There are several factors that make DE an economic choice for customers in this area. First, the utility rates are significantly greater than operating cost of DE systems during on-peak periods. Second, the state of California offers significant incentives that reduce the customer's capital cost of installed DE equipment. Third, the interconnection requirements are well established by California's Rule 21.

Utility revenues are determined for the most part by the amount of energy sold, but their capital expenses are largely determined by the peak load served. To meet the peak loads with an adequate reserve margin, utilities must install T&D capacity greater than their expected peak load. This often translates to a capacity 50% (or more) greater than their average load. The ratio of average load to installed capacity is called the load factor. Depending upon the rate structure, any increase in the load factor could increase the utility's return on investment.

As the peak load grows, the utility must usually increase the installed capacity of the equipment serving the load. These increases must be made in increments determined by the commercially available equipment and by the economies of installation costs. Because of the incremental, or lumpy, nature of the capital expansion, the growth in distribution system capacity must usually jump far ahead of the growth in peak load. This in turn leads to reductions in the load factor until the load catches up with the capacity, at which time the cycle starts anew. This is shown by example in Figure 11 for a prototypical circuit with a 3%/year peak load growth and a circuit upgrade factor of 50%[3] (The circuit upgrade factor is the capacity increase relative to the current capacity). This 'lumpiness' is exacerbated by the highly localized nature of distribution system investments. Therefore, the reserve margin on a distribution circuit can range from 5% to 100%, depending on how recently the capacity was installed or increased and the growth rate of the load on the circuit. The determination of the distribution system reserve margin is further complicated by the ability to operate at loads above the equipment's rated capacity during critical periods. In contrast, the overall system generation reserve margin can be maintained at a relatively steady value, often about 20%, by well-planned additions of generation capacity or firm power purchase contracts.[30,31]

Figure 11 - Incremental Circuit Capacity Upgrades Relative to Circuit Peak Load Growth



In some situations, therefore, DE can increase utility return on investment by serving to improve the load factor for T&D resources. This can occur if the DE resource is used to provide power only during peak times or if the DE resource is used to delay a capital expansion until the load has increased to a level commensurate with the incremental expansion value. The DE utility economics also depend on whether the DE is owned by the utility itself or by the customer. Utility savings due to the cancellation or deferral of circuit expansion occur for both cases. If the DE is customer-owned, the net economic effect on the distribution utility also includes reductions in the utility's cost of purchased power, and reductions (net of any increases from standby charges) in the utility's revenue from power sales.

Circuit Expansion Cost Savings Estimates

The circuit peak loads, inflated by some contingency reserves factor, represent the capacity that the utility must provide at the substation and in the wires. As the load approaches this limit, the utility must usually invest capital to increase the circuit capacity to reliably meet the consumers' demands. The cost of capacity additions tends to be location-specific and varies widely. Two recent studies used FERC Form 1 data to estimate the marginal cost of T&D. FERC accounts 360-368 contain distribution equipment that could be deferred or displaced by DE systems.[32]

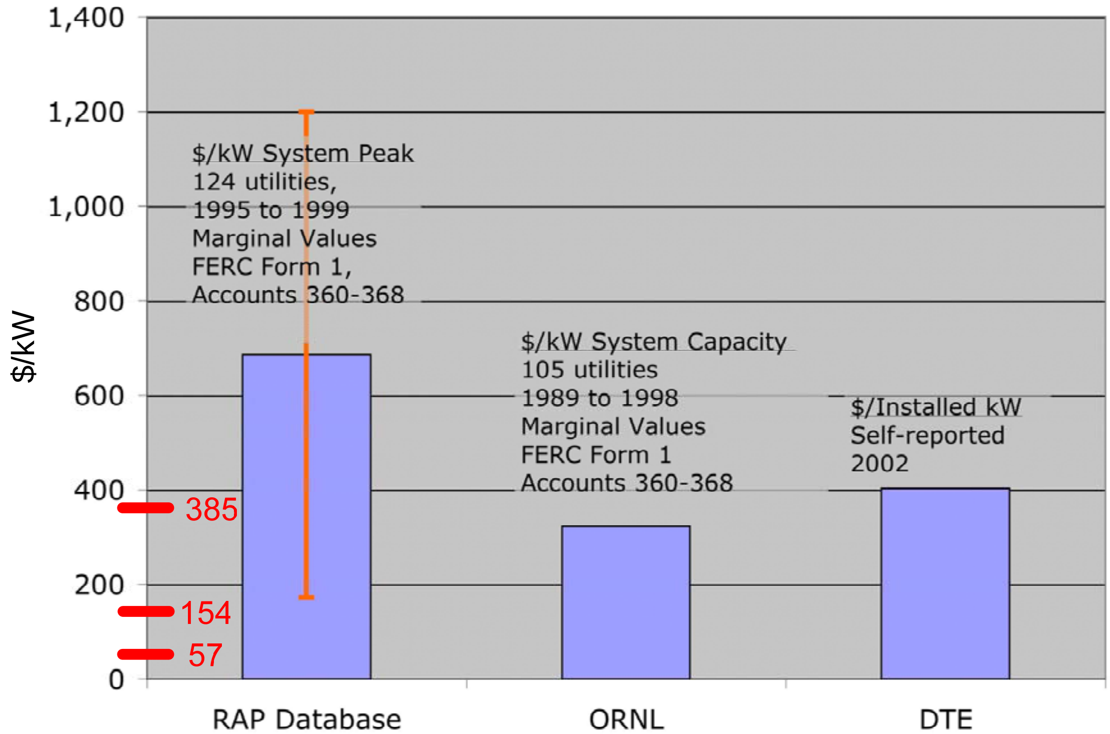
The first study, a part of the Regulatory Assistance Project (RAP) Distributed Resource Policy Series, examined the marginal T&D expansion costs for 124 utilities.[20] This study found the national average cost between 1995 and 1999 was $590/peak kW for lines and circuits and $95/peak kW for transmission and substations. The standard deviation for each of these averages, $447/peak kW for lines and circuits and $91/peak kW for transmission and substations, indicates the broad range of the reported costs.

The RAP results are all based on the utility peak load, which tends to grow in a smooth and continuous manner. Capacity additions, on the other hand, tend to occur in discrete steps that correspond to available equipment sizes (e.g. rotating stock) or to capacity increments that justify the installation labor costs. For that reason, another study, performed by Oak Ridge National Laboratory (ORNL), used the total installed kVA for distribution line transformers, rather than the system peak, to examine the marginal costs for 105 major utilities over the period from 1989 to 1998.[33] The marginal distribution cost from that study (defined as the sum of both classifications from the RAP study, or $685/peak kW) was $239/kVA. To compare these two numbers, it is necessary to correct for power factor. If we assume that the power factor is 0.9, then the second study's value of $239/kVA would be $266/ kW.

This is still not a direct comparison, however, because one value is based on the system peak load and the other on the installed capacity. These two values would differ by a factor equal to the reserve margin, which varies from one location to another. For example, if the reserve margin is 15%, then a cost of $685/peak kW would be equal to a cost of $582/installed kW. The reserve margin also varies with time, being greatest immediately following a circuit upgrade, and being least right before a circuit upgrade.

A summary of these marginal T&D cost estimates is shown in Figure 12. The average, plus or minus one standard deviation, is shown for the RAP database after several outliers were removed. Even after excluding three very high-priced outliers, the data ranged from $127 to $3,085/peak kW.[34] In the DTE case, the utility's T&D average upgrade cost was $403/kW.[3]

Figure 12 - Summary of Marginal T&D Cost Estimates



As required by the California PUC, SCE is preparing to issue a request for proposals (RFP) for DE to meet capacity requirements at specified locations. Because of the sensitivity of the bidding and proposal selection process, they were not able to share their T&D expansion cost data for the case circuits. It is anticipated that they will offer an arrangement where an amount is paid to a DE operator for the first year's deferral, with subsequent annual payments that decline as the length of the deferral becomes shorter. This arrangement will allow the utility to increase the load factor for its equipment, while spending less for the DE capacity than it would have cost the utility to install new T&D resources.

One way to determine the annual T&D cost to the utility, disregarding revenue growth, is to determine the annual carrying cost of a T&D expansion. SCE was able to provide historical cost data for recent upgrades similar to those that may be done on the Lincoln and Washington substations. Two 13,000 kW circuits were added to two separate substations at installed costs of $740,762 and $750,500, for an average installed cost of $57/kW (a comparatively low cost, see Figure 12). Assuming SCE's annual fixed charge rate is 12%[x], the average annualized carrying cost for each 13,000 kW upgrade would be $90,000/year. Assuming load growth of 1.3% (as defined for Justice) on a 13,000 kW circuit, the growth would be 170 kW for the first year. Because the minimum size of the circuit expansion, 13 MW, is so much larger than the needed expansion, the first-year deferral cost would be $530/kW per year for a 170 kW DG installation. Even if the expansion circuit relieves similar growth problems on an adjacent circuit, so that a DG capacity of 340 kW is needed, the annual deferral cost would still be $260/kW for the first year. As this example shows, the annual deferral cost is a function of the avoided cost of the circuit upgrade, the fixed charge rate, and the size of DG that would meet the short-term needs of the circuit's growth.

$$\text{Deferral cost} = \frac{\text{Avoided upgrade cost}}{\text{Alternate upgrade capacity}} \times \frac{\text{Fixed Charge Rate}}{\text{DG Capacity Required}}$$

Customer Owned DE Systems

Using customer-owned advanced energy technologies on the Justice and Prosper circuits to defer circuit expansion could be an economical choice for SCE, depending on the marginal T&D upgrade cost estimates and the amount of load reduced on the circuit due to customer-owned technologies. When customers control their DE system operation, they may choose to reduce their load at times other than the utility's peak load times, which would reduce the customer's overall energy costs, with a corresponding reduction in utility revenues. However, the reduction in total energy sold is not necessarily proportional to the change in utility revenues because the reduced sales revenue is a function of the rate schedule, including demand charges, and any standby charges that apply to the DE system. Also, much of the power displacement would occur during on-peak periods when the utility's cost of purchased power is greatest.

Because of the extreme range in T&D upgrade costs and uncertainty related to customer-owned technology deployment on the circuit, a set of scenarios were investigated in terms of net-present-value to the utility, for the Justice circuit. Detailed cash flow charts for each of the scenarios are shown in Appendix E.

For the first scenario, the circuit condition allows the utility to simply upgrade the capacity from 13 MW to 19 MW for $600,000, or $100/kW.

For the second scenario, the utility installs a new 13 MW circuit at a given cost, but no customers install advanced energy technologies despite economic reasons to do so. For the circuit upgrade cases, the utility makes a lump-sum payment for the upgrade in year zero, but gains revenue each year after that due to load growth. Three circuit costs were investigated, all on the low side of the data range from the RAP database (See Figure 12).

1. Circuit installation cost is $746,000 or $57/kW.
2. Circuit installation cost is $2 million or $154/kW.
3. Circuit installation cost is $5 million or $385/kW.

For the third scenario, the utility promotes a degree of load reduction through customer-owned technology and does not make a capital investment toward capacity. The utility still gains revenue each year due to load growth but loses revenue due to load-reducing energy technologies. Two degrees of load reduction were investigated.

1. Customers collectively install 4,200 kW of CHP, as proposed in Table 9, and based on the market adoption curves; 3,000 kW the first year and 600 kW for the following two years. Because the facilities are peaking at different times, the combined load reduction is not 4,200 kW. Load is reduced by about 85% of the total installed CHP generation capacity, or about 3,500 kW.
2. Customers collectively install 2,000 kW of CHP (lower than what market conditions might offer). However, in this case, the CHP is installed more gradually over seven years; 500 kW in year 1, and then another 500 kW in years 3, 5, and 7. Once again, load is reduced by about 85% of the total installed CHP generation capacity or about 1,700 kW in total.

For the last scenario, the utility installs a new 13 MW circuit assuming that no customer-owned technologies will be installed, but customers do install technologies for economic reasons. Once again, two degrees of load reduction were investigated.

1. Utility installs a new 13 MW circuit at a cost of $3 million and customers on the circuit install 4,200 kW of CHP; 3,000 kW the first year and 600 kW for the following two years.
2. Utility installs a new 13 MW circuit at a cost of $3 million and customers on the circuit install CHP, EE and PV with an integrated demand reduction of 4.3 MW over ten years.

Figure 13 and Table 16 summarize the 10-year net-present-values (NPV) that the utility could expect for each of the scenarios (See Appendix E for detailed cash flows).

Figure 13 – Possible Economic Outcomes for Utility

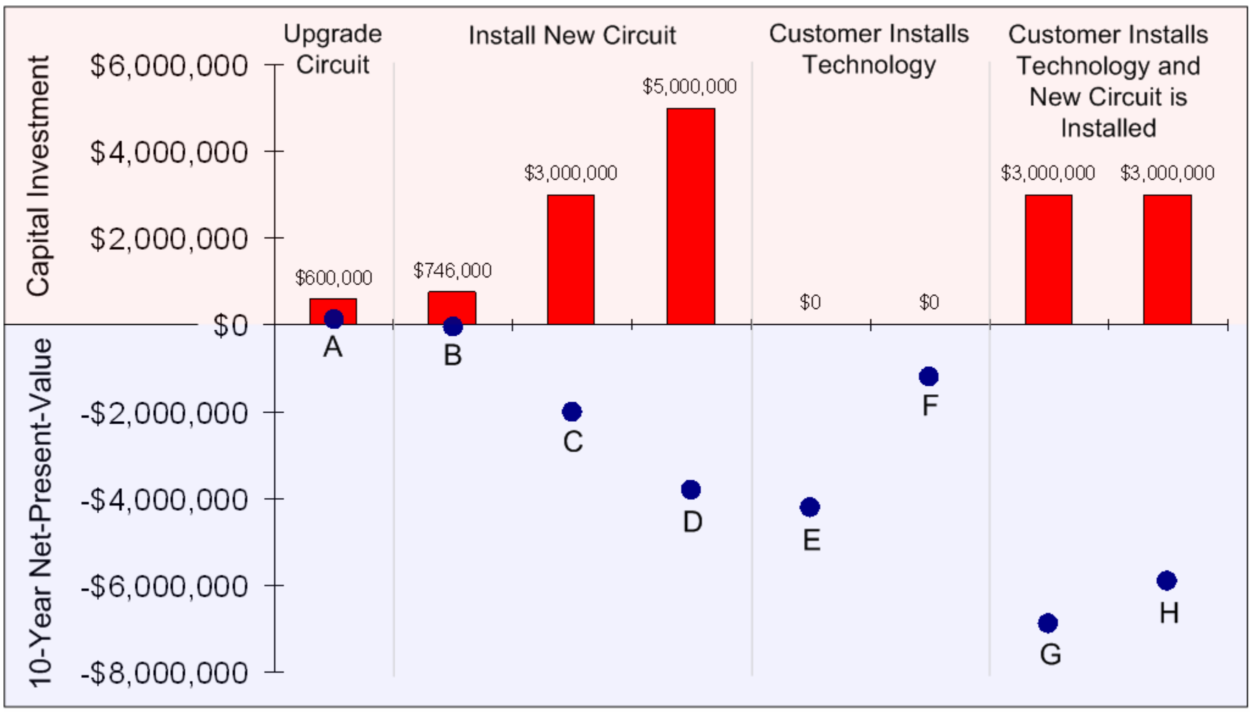


Table 16 – Possible Economic Outcomes for Utility

Scenarios		10-Year NPV
A	Utility Upgrades 13 MW Circuit Capacity to 19 MW in Year 0 for $600,000	$100,000
B	Utility Installs 13 MW Circuit in Year 0 for $746,000	-$40,000
C	Utility Installs 13 MW Circuit in Year 0 for $3,000,000	-$2,000,000
D	Utility Installs 13 MW Circuit in Year 0 for $5,000,000	-$3,800,000
E	Customers Install 4.2 MW of CHP over 3 yrs	-$4,200,000
F	Customers Install 2 MW of CHP over 7 yrs	-$1,200,000
G	Utility Installs 13 MW Circuit in Year 0 for $3M and Customers Install 4.2 MW of CHP over 3 yrs	-$6,900,000
H	Utility Installs 13 MW Circuit in Year 0 for $3M and Customers Install Economically Feasible CHP, EE, and PV over 10 years	-$5,900,000

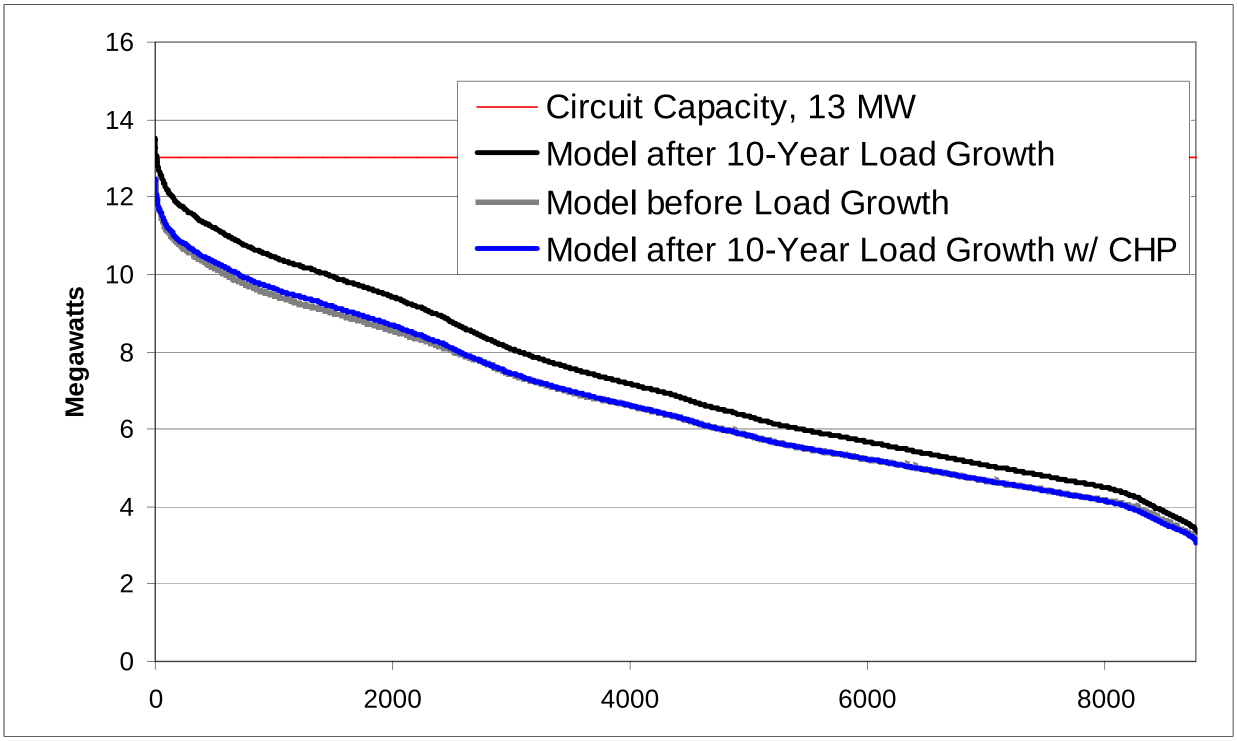
Figure 13 and Table 16 show that upgrading the circuit capacity by 50% to 19 MW is the most economical long-term investment for SCE if the circuit and load conditions are appropriate. Installing a new 13 MW circuit at a cost of $746,000 is the next best investment as long as no customers invest in significant load-reducing technology despite economic reasons to do so. However, if customers on the circuit react to the economic conditions and install 4,200 kW of CHP over the next three years, SCE would incur a substantially higher loss in terms of net-present-value. The overall cost to SCE is compounded if the customers install CHP and the utility installs a new circuit that would ultimately be unnecessary and effectively become a stranded asset.

The scenarios shown in Table 16 must be observed with discretion. In many cases, utilities have the option to simply upgrade circuit capacities; and in many cases the upgrades can be done at low cost (e.g. $100/kW or less). However, one of the premises of promoting customer-owned advanced energy technologies on selected circuits for load relief is that those circuits with the greatest upgrade costs would be chosen. The Justice circuit serves an area where cables must be buried rather than run overhead. Furthermore, it is possible conditions justify a new circuit rather than an upgraded capacity. These two scenarios combined can generate considerably higher capital costs. If a new 13 MW circuit were to cost the utility $2 million or more, customer-installed CHP could economically defer the need for an additional circuit. However, to preserve utility revenues, the amount of CHP that is installed on the circuit must be considerably less than 4,200 kW and the CHP must be installed gradually so that load reduction is at nearly the same pace as base load growth. If 2,000 kW of CHP is installed over the next seven years, the need for an additional $2 million circuit could be economically deferred for ten years.

Through appropriate price signals, the utility could influence the amount of DE, EE and PV that is deployed on the circuit, thereby tailoring a more ideal scenario. Or the utility may choose to contract with customer(s) to reduce load at the utility's signal, either through the use of a customer-owned DE or through other demand reduction methods. These scenarios would be particularly attractive in high-growth areas where advanced energy technologies can be installed more cost effectively for new construction, which only impacts future electric load growth and leaves current revenue streams unscathed. However, with customer ownership, the utility must either accept some element of diversified uncertainty or install a hardware mechanism to provide physical assurance that the load will be removed from the utility circuit. The customer-owned DE equipment can be a part of a CHP system, but it must be capable of generating electricity independently of the thermal load to ensure that electric power is available during the peak circuit load hours.

Figure 14 shows a load curve where the future peak demand outlook of 13.5 MW is kept below the circuit capacity with 2,000 kW of CHP installed gradually over the first seven years of the study period. This scenario would impact future revenue growth but leave current revenue intact.

Figure 14 – Justice Circuit Impact Model – 2 MW of CHP



Portable Utility Owned DE Systems on Utility Property

Utility-owned DE was considered to provide peak shaving for the Justice circuit. Using the Justice circuit model, without the residential load and after ten years of load growth, all grid demands greater than 90% of the circuit capacity, or 11.7 MW were identified. To maintain this limit, a total DE capacity of 1.83 MW would be required. This was modeled by assuming that three engines were installed with capacities of 700, 600, and 600 kW at a total installed cost of $1,500,000. To meet the demand, the 700 kW machine would operate for 246 hours, representing 118 on-off cycles. One 600 kW machine would operate for 69 hours (57 on-off cycles) and the other for only 9 hours (7 on-off cycles). Figure 15 shows the periods of greatest demand served by each of the three engines.

Figure 16 is a close-up look at the high end of the load curve (using a logarithmic axis to expand this portion of the plot), again focusing on the peak loads served by the DE. Using three machines provides a backup engine except for those 9 hours when all three engines are needed. Annual O&M costs would be about $3,200 and fuel costs would be about $13,000. The utility would defer the circuit upgrade cost; and after the local system load growth reaches the point where a step change in T&D capacity can no longer be deferred, the DE system can be moved to another grid location and provide further cost deferrals. This portability can make the DE system economically attractive, even if the deferred savings at one particular location are less than the installed cost of the DE.

Figure 15 – Peak Shaving with Utility-Owned DG on Justice Circuit

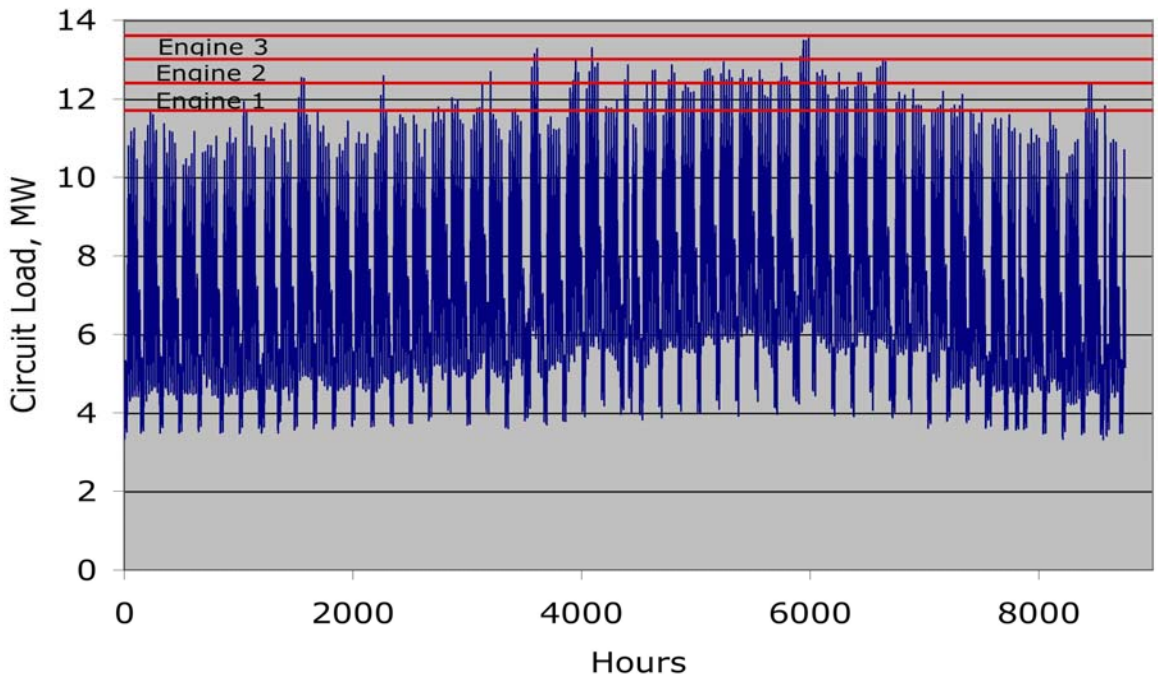
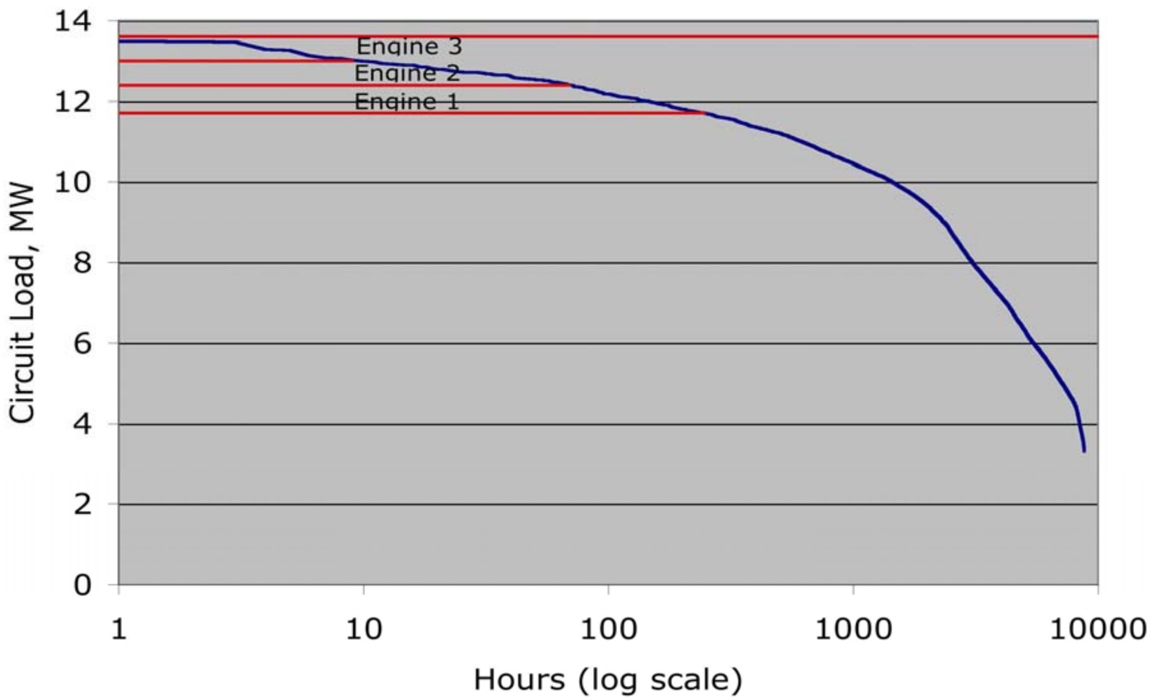


Figure 16 - Peak Shaving with Utility-Owned DG on Justice Circuit (Log Axis)



A compelling case can be made for energy storage devices as well if the circuit upgrade cost is roughly $550/kW or more. Three energy storage devices could be installed at the same capacities as the engines for a total installed cost of $3,420,000 and a 12-year life expectancy ($1,800/kW – See Appendix D). Annual O&M costs would be about $5,100. As opposed to fuel cost, the storage devices would need to be charged at a charging efficiency of 75%, and the required power would cost about $22,400 annually. The charging cost assumes that the batteries are discharged during on-peak hours and charged all other hours, as shown in Figure 17. Table 17 shows the storage device-charging schedule.

Figure 17 – Storage Device Discharge/Charge Schedule

Summer	Hour of the day																							
Weekdays	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
On Peak																								
Mid Peak																								
Off Peak																								

Discharge
Charge

Table 17 – Storage Device Charging Cost Schedule

Capacity	Discharge Hours	Discharge kWh	Charge kWh	On-peak	Mid-Peak	Off-Peak	Total
700	246	172200	229600	$1,700	$8,700	$7,200	$17,600
600	69	41400	55200	$400	$2,100	$1,700	$4,200
600	9	5400	7200	$100	$300	$200	$600
							$22,400

ANCILLARY RESEARCH

Demand Response

Section Objective: Summarize the overall potential impact of demand response and specifically illustrate the impact of thermostat setback and light dimming on the circuits.

A robust array of demand-response programs in California could result in an 8% reduction in electric demand.[35,36]

The U.S. Government Accountability Office (GAO) identified two types of demand-response programs currently used, on a limited basis, by utilities across the nation.[37] Both program types, market-based and reliability-driven, have the potential to reduce peak electric demands through various strategies, as follows:

Market-Based Pricing Programs: Enable customers to adjust their use of electricity in response to changing prices.

1. Time-of-use pricing: Pre-established prices in effect for predetermined periods of the day and season.
2. Real-time pricing: Hourly pricing closely linked to variations in actual hourly cost of supply.
3. Demand bidding: Enables large customers to react to changing wholesale prices by offering bids to supply their large blocks of potential demand reduction to the grid operator.

Reliability-Driven Programs: Enable grid operators to ask customers to reduce electricity use when hot weather or system malfunctions mean that demand will probably exceed supply and cause a blackout.

1. Interruptible Rates: Provide customers with discounted prices during all hours in exchange for the right of the grid operator or utility to interrupt electricity service if needed.
2. Direct Demand Control: Compensate customers financially if the customers allow the grid operator or utility to remotely interrupt electricity used by one or more electrical devices.
3. Voluntary Demand Reduction: Allows the customer to decide how much electric demand, if any, it wants to reduce from an agreed-upon baseline level.

Effects of Thermostat Setback

RLW Analytics, Inc. (RLW) studied the impact of SCE's Energy$mart Thermostat^{SM} program (E$T).[38] The program provides small commercial customers in SCE's service territory with two-way programmable thermostats. SCE uses software to remotely curtail the HVAC load of the participants during critical periods by sending out a radio signal. When the curtailment is activated, the thermostat raises the cooling set point by a specified number of degrees, called the temperature offset, thereby reducing the cooling load. The thermostat sends a radio signal back indicating that it has received the signal and has implemented the temperature rollback. The thermostat also reports any overrides by the participant.

The study determines the feasibility of small commercial load control and demand responsiveness through the use of Internet technology and thermostats to affect HVAC energy use. The results can be applied to this study as well.

SCE's target market for the E$T program included, as recommended by the California Public Utility Commission (CPUC), small commercial customers under 200 kW (inherently customers on their GS-1 and GS-2 rate classes) in geographical areas known to have high electricity consumption due to climate. The target market limited customers in rural areas because adequate radio signals often could not be achieved. A total of 4,325 customers participated in the E$T program and received free thermostat equipment and installation in addition to a $300 per year incentive. The study shows that a four-degree, two-hour curtailment between 2 p.m and 5 p.m. on a hot summer weekday would result in a coincidental peak demand reduction of 10 MW. That corresponds to an average 2.3 kW of coincidental peak demand reduction per participant.

The proposed three-hour curtailment is based on RLW research data indicating that the buildings reach their four-degree temperature offset near the end of the third hour of curtailment.

Effects of Thermostat Setback on the Justice Circuit

About 140 customers on the Justice circuit are on GS-1 and GS-2 rate classes and demand between 1 kW and 200 kW. The 140 customers represent about 38% of the total peak demand on the circuit. If all 140 customers participated in the E$T program and each reduced their coincidental peak demand by an average of 2.3 kW, the total reduction would be 322 kW or about 2.7% of the circuit peak demand.

Effects of Thermostat Setback on the Prosper Circuit

As previously discussed, the Prosper circuit serves a very rural area. E$T program participation would likely be minimal and produce negligible demand reduction.

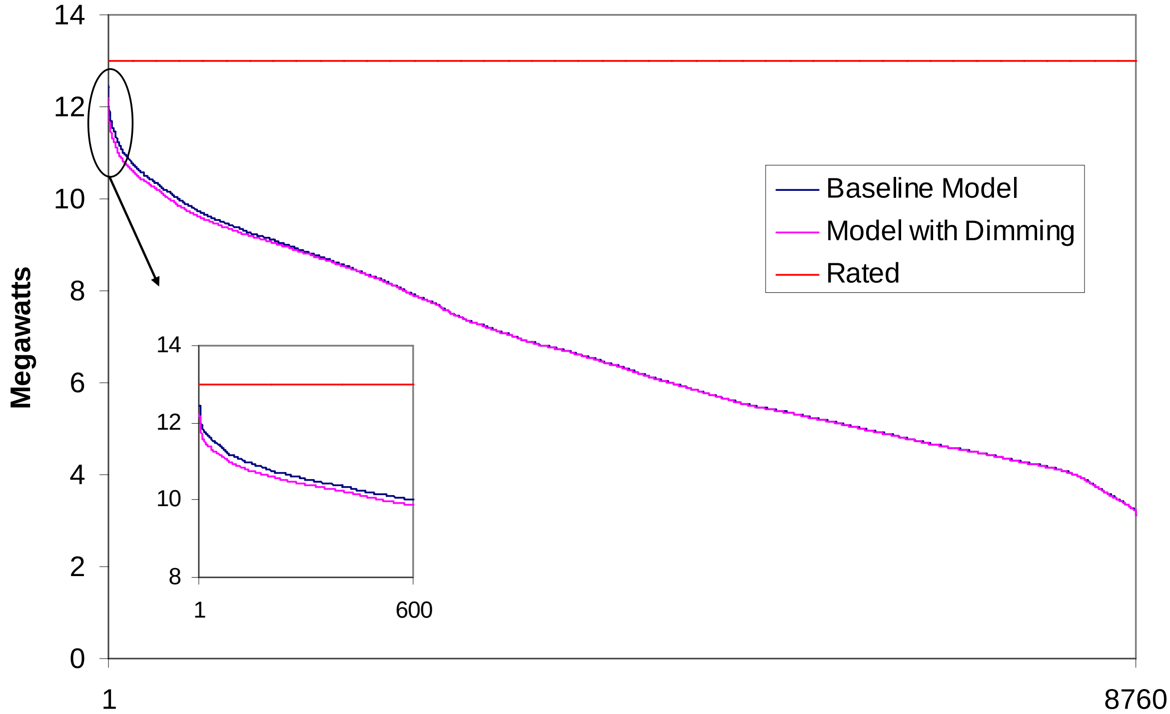
Effects of Dimming Lights

Energy-efficient lighting and load-shedding ballasts that can respond to a signal sent by power line carriers could provide electric demand reduction. Typically, these ballasts have maximum level dimming capability of 33%, in part to avoid warranty problems with lamp vendors.

From the Justice LDC, it was found that the majority of peak load during the year (top 600 hours) occurs between 1 p.m. and 4 p.m. during weekdays. The combined lighting demand of three customers represents 10% of the total circuit energy consumption. To demonstrate the effects of demand reduction via dimming on the Justice circuit the three largest customers were equipped with dimming ballasts throughout the facility models. The ballasts were dimmed by 33% between 1 p.m. and 4 p.m. during all weekdays.

The results are reflected in Figure 18 and show demand reductions of 100 kW to 200kW, or up to 2% of the peak demand during the highest 1,000 hours of the LDC. Over 30 additional customers would need to participate in ballast dimming to double the peak demand reduction from 2% to 4%.

Figure 18 – Peak Load Reductions from Dimming Lights



Advanced Energy System Demonstration

Section Objective: Document a successfully installed, utility-owned portable DE demonstration system used for electric demand peak shaving.

In support of this study, AEP conducted an R&D demonstration project that included the development, installation, operation, and performance of DG equipment on an AEP distribution system in Ohio. The intent of the project was to demonstrate the concept of: 1) utilizing commercially available generation equipment to reduce electrical peak load on thermally-loaded distribution station facilities; 2) deferring a major capital investment and allowing sufficient time to implement a plan to upgrade the 23 kV sub-transmission and station facilities to 69 kV; and 3) verifying the integrity of data security and use of wireless/digital cellular communication equipment at remote locations on the distribution system.

Recent changes in technology and industry interconnection standards, plus advances in equipment design in the application of microprocessor controls and power electronics, provided an opportunity for AEP to investigate the application of DG systems at remote locations. In addition, emerging applications of wireless/digital cellular communication equipment, plus successful application of this emerging technology in a prior AEP R&D project experience, provided an opportunity for AEP to: 1) expand the application of wireless/digital cellular communication equipment; and 2) use the Internet and a data technology center server to achieve additional benefits for AEP Distribution.

A DG Demonstration Team was established in the beginning of this project and represented various departments within AEP. This R&D project began in March 2004, with the DG system commissioned on June 29, 2004, prior to the summer peak season, and the system was operational through November 2004. This project included installation of a mobile synchronous generation package in a semi-trailer, located at a remote site and adjacent to a distribution station in Ohio. The station included a transformer that was projected to exceed its thermal limit several times (i.e., days) during the 2004 summer peak season. The mobile generator was programmed to provide a continuous power output of 600 kW and reduce electrical load on the station transformer and on the corresponding 23 kV sub-transmission system.

The results of this DG demonstration allowed the planned station improvement project to be deferred by one year without risking an overload of the station transformer and provided 600 kW of DG during the 2004 summer season. More importantly, deferral of the planned capital improvement project allowed sufficient time to provide a more reliable 69 kV plan in the area at a comparable capital cost.

In addition, installation of DG equipment provided an opportunity for System Planning, Operations and other groups in AEP to gain experience with remote operation and control of DG equipment interconnected to a distribution circuit and station.

During the development phase, the DG Demonstration Team uncovered some major challenges associated with developing and implementing this DG demonstration, mostly involving interconnection and remote operation of DG equipment on the distribution circuit. The team investigated and resolved the issues, and documented the solutions for future projects.

In addition to the technical challenges, seasonal weather-related conditions did not materialize as expected from prior years, with ambient temperatures being below normal and moisture content being above normal. This weather-related condition was unpredictable, resulting in the peak load at the station not increasing as projected. Thus, automatic control settings of the DG demonstration needed to be adjusted during the 2004 summer months.

The outcome of the project and solutions developed by the DG Demonstration Team provided multiple opportunities and value for AEP Distribution. The project showed that commercially available mobile DG systems could be used in a cost effective manner to reduce electrical peak demand on distribution station and sub-transmission facilities, deferring by one or more years the need for capital-intensive improvements. For the Ohio study area, the financial benefits of deferring the $1,887,000 capital investment by one-year resulted in a 2004 savings of $178,900 (i.e., annual carrying charge, based on a 14.36% carrying charge rate, less the DG demonstration project cost, plus co-funding for the project). The knowledge and experience gained from this project will dramatically reduce the cost of future installations.

This R&D project expanded the application and use of a new communication platform, which was developed by the AEP Dolan Technology Center for a separate Distribution VAR Control Project, and demonstrated a cost effective method to monitor and control the operation of remote

DG equipment. In addition, this project employed emerging wireless mesh network and digital cellular communication technologies. Utilizing new wireless communications in an existing station provided tremendous value by eliminating the need to install cables within a station fence to monitor distribution circuits and transformer loading. Capitalizing on the emerging digital cellular infrastructure allowed AEP to leapfrog existing communication technologies and provide a gateway to the Internet. With this successful demonstration, AEP can build on this technology and increase benefits at remote stations to monitor, in almost-real-time, distribution station and circuit loading, as well as equipment status, for system planning and operation.

DE Interconnection under California's Rule 21

Section Objective: Identify outstanding technical issues, if any, in Rule 21 that might interfere with the types of DE installations envisioned for this study.

In December 2000, the California Public Utilities Commission (CPUC) approved the Rule 21 language adopted by the California Energy Commission (CEC) as standard interconnection practices.[39] Rule 21 and its adoption by the CPUC is a seminal contribution to the field of DE policy because Rule 21 is one of the first standard interconnection policies implemented by a state with a significant number of DE installations. Since its implementation, almost 490 MW of DE have been authorized to interconnect in California under Rule 21.[40] In support of this study, a group of DE developers led by Redwood Power reviewed Rule 21. They found no outstanding interconnection issues that would interfere with the types of DE installations envisioned for this study.[41] However, Redwood Power reported that a key opportunity exists to make Rule 21 more productive from a developer's perspective while satisfying utility safety concerns. A modification to the rule could reduce the considerable economic risk to developers associated with the interconnection review timing by requiring a preliminary conceptual review by the utility. This preliminary review would be used to identify potential fatal flaws in interconnection and to determine whether additional facilities would be required. The scope of the proposed conceptual review would be limited to the five issues listed in Table 18, which could be answered completely with only cursory information and which have the greatest impact on the cost of interconnecting a DE system.

Table 18 – Scope of DG Interconnection Conceptual Review by Utility

Item	Review Item by Utility	Potential Problem	What needs to be submitted to the Utility to review this item
1	Is the DG system to be interconnected located on a radial or network connected system?	Network connected systems create a great deal of facility upgrades that create greater costs than most radial connected systems. Items such as network protector upgrades can create large cost increases to the DG system installation.	Building address and service meter numbers at building under review. Sizes of proposed generators, and service meter numbers that generators are to be connected to.
2	What is the short circuit contribution ratio (SCCR) of the proposed DG system?	The DG system may require additional protection for loss of synchronism if the SCCR is greater than 0.05. If the DG system has a SCCR exceeding 0.1 it shall be required to be equipped with protective functions to sense distribution faults, added distribution system studies may be required, and the installation of transfer trip may be required.	Generator short circuit contribution value at the point of common coupling (PCC), and show the meter or service the short circuit is contributed to.
3	What type of distribution system is the proposed DG system connected to (voltage level, phase and quantity of wires). Does this system feed single phase customers on the same line? Are high speed distribution protectors installed on the distribution line?	Review if any additional ground bank requirements are needed or reclose blocking is required.	Building address and service meter numbers at building under review
4	Will the proposed DG system be operating in an export mode?	Export type projects can create additional review time and possibly the installation of added facilities.	Sizes of proposed generators and service meter numbers that generators are to be connected to.
5	What is the peak load on the line section that the DG system is proposed to be connected to?	Reclose blocking may be required for distribution system re-closures if the DG system exceeds 15% or the peak load on the line section	Building address and service meter numbers at building under review. Sizes of proposed generators, and service meter numbers that generators are to be connected to.

Redwood Power and the group of developers also noted that Rule 21 faces an unresolved policy issue that could make a considerable impact on the cost of DE installations. A standard metering information protocol does not currently exist but would allow for the elimination of redundant technologies. This issue has been under consideration within Rule 21 working groups for two years.

Effects of DE Resources on the Power Distribution System

Section Objective: Identify, for near- and long-term DE trajectories, potential technical issues with interconnecting DE resources to the electric grid.

National Renewable Energy Laboratory recently conducted a multiyear research program that focused on the dynamic behavior of power systems when a portion of the total energy resource is distributed generation.[42] The effort examined response to events such as short circuits on power lines, line-switching operations, and load fluctuations for both near-term and long-term visions of DE resources on the electric grid. The near-term industry trajectory on DE resources is mostly toward conventional, synchronous-machine-based rotating generation with controls that are focused on the needs of local power systems. In the long-term, the majority of DE resources may rely on power electronic inverters for connection to the power system. These technologies include fuel cells, photovoltaics, and microturbines. Research showed that, in the long-term, as the penetration of DE resources significantly increases, the performance requirements for the DE resources become broader. The ability to achieve the desired performance with an autonomous local interconnect becomes limited, and penalties for undesirable behavior, such as over-aggressive tripping, become greater. For the near-term outlook, research showed that the more conventional synchronous DE resources are largely benign for the power distribution system, with the exception of over-aggressive tripping.

Interconnection standards for DE, including California's DE interconnection standards, have requirements for under voltage and under frequency tripping of DE. These requirements are directed at ensuring that DE rapidly disconnects in response to problems on the distribution system. However, because large-scale disturbances, such as the tripping of a large multiunit power plant, can cause widespread voltage and frequency excursions, this requirement is a potential concern for aggressive DE tripping.

NREL suggests that aggressive tripping of DE in response to under-frequency and under-voltage may present a substantial hazard to the bulk distribution system. In general, tripping of DG should be designed to take the local load with it. Simultaneous tripping of DG that takes hours to bring back online, in a system dependent on the DG output can result in widespread and severe voltage problems. Currently, IEEE standards are biased in favor of fast tripping to rapidly detect and eliminate inadvertent islands. However, there may be a need for further consideration of the fine balance between island avoidance and making the distribution system vulnerable to voltage collapse.

Despite the potential of over-aggressive tripping, careful planning and widespread adoption of properly designed DG and CHP systems can help stabilize the grid. DG/CHP units can be useful to utilities that require reserve capacity or reactive power or want to intentionally island or off-load demand to deal with potential or developing blackouts.

Circuit Flicker Analysis with DE

Section Objective: Examine the effects associated with the starting and stopping and system output fluctuations of the proposed DE system installations on circuit voltage flicker.

Recent work has been done to address the issue of whether DE resources enhance or degrade circuit reliability. One study, funded by the CEC, examined the Silicon Valley area and found that strategically positioned DE can increase the overall system efficiency by reducing congestion on both the distribution and transmission level. The DE was also found to provide local voltage support, thus reducing the need to burden the system as a whole with the wasteful additional current loads that occur when voltage-supporting reactive power is supplied from a remote location.[43]

Voltage flicker and fault currents are two of the most significant concerns utilities currently have with respect to circuit reliability and power quality. Flicker, voltage flicker, light flicker, and lamp flicker are different names for the same phenomenon, a fluctuation in power system voltage that results in a visible change in the output of lighting systems. With industry's increasing concern over the impact of power quality on productivity, voltage flicker is an important issue that needs to be addressed when planning to add new DE to a power system.

In support of this study, a team from Virginia Polytechnic Institute modeled the Justice circuit to examine the effect of the proposed DE installations on voltage flicker. They performed both a theoretical evaluation and a computer simulation, using the Distribution Engineering Workstation (DEW) [44] model to examine a series of worst-case analyses for the four most likely DE installations on the SCE suburban circuit.[45]

These analyses compared the voltage flicker associated with DE system starting and stopping and DE system output fluctuations to the voltage fluctuation thresholds at different frequencies defined in several industry standards.[46] The theoretical analysis shows that the distribution system is weaker at locations farther away from the substation. If a significant level of DE is located at a relatively weak location, voltage flicker problems may be experienced, although smaller DE systems placed at the same weak location will produce no detectable voltage flicker. A higher level of DE can be safely installed at stronger locations. Two of the proposed DE systems in the analysis would not cause noticeable flicker if their entire DE system failed up to one time per hour. One of the DE systems could fail up to 24 times per minute and still cause no voltage flicker problem anywhere in the circuit. The fourth DE was located in a robust portion of the grid and would not cause flicker problems under any failure frequency.

DE Availability/Probability

Section Objective: Illustrate the overall probability that the proposed DE systems will be available to provide load support on the electric grid.

Using the Justice circuit as an example and assuming that the two industrial customers and the school/church install DE systems, there would be a total of four 300 kW machines and two 1500 kW machines on the circuit (See Table 19). Availability of DE systems for the two unit sizes have been estimated at about 96% to 98% as per operational reliability data collected by Energy and Environmental Analysis Inc.[19]

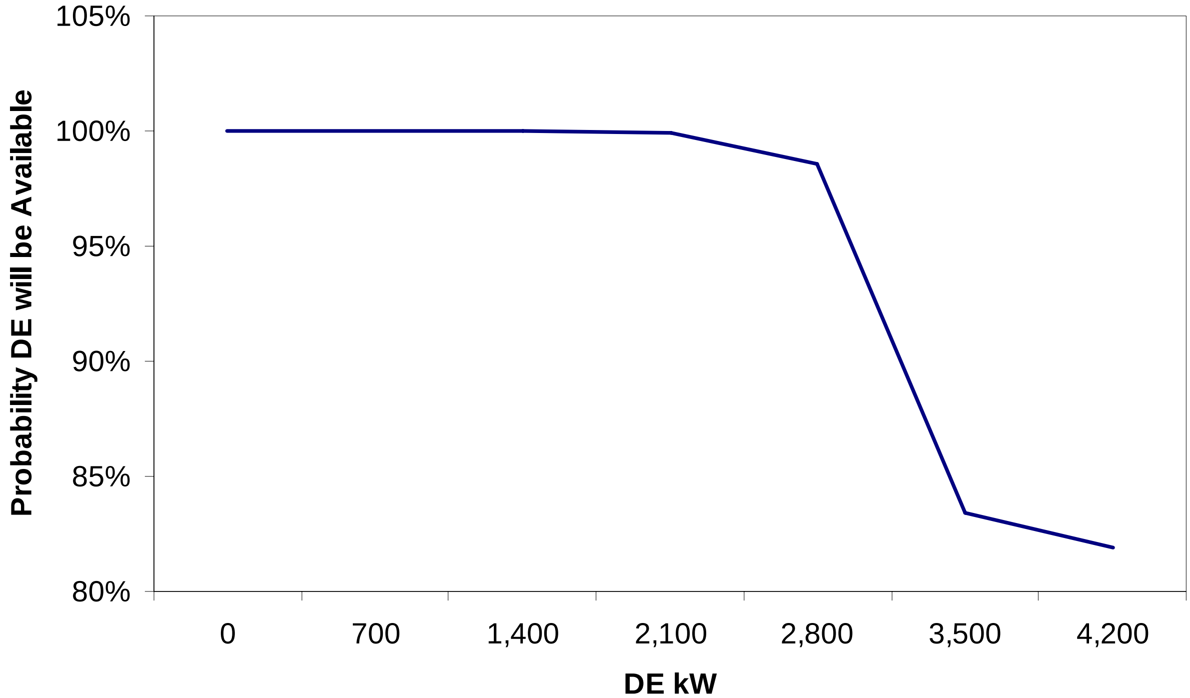
Table 19 – Availability of DE Facilities on Justice Circuit

Facility	Gen kW	Unit Qty	Unit sizes	Availability
Church/School	600	2	300	95.99%
Industrial	3000	2	1500	98.22%
Industrial	600	2	300	95.99%

Figure 19 shows that, across 365 days, the combined availability of the DE systems on Justice is very near 100% for about 50% or 2,100 kW of the total 4,200 kW DE capacity.

Grid reliability is estimated at 99.98%, per Appendix B, and is based upon the diversity of thousands of generators feeding power to the system. Similarly, DE power becomes more reliable on a diversified basis when more machines are introduced to the system.

Figure 19 – Diversified Availability of DE Facilities on Justice Circuit



Cost Sensitivities

Section Objective: Identify installation costs required to achieve successful customer adoption of advanced energy technologies and illustrate reductions in customer adoption due to higher prices.

A price-point analysis for DE, EE, and PV technologies was done for all of the facilities on each of the circuits. An allowance was calculated for each case that corresponds to the maximum price that a developer could spend and still achieve a 5-year payback. Table 20 shows the average allowance in \$/kW, \$/ft^2, and \$/kW for CHP, EE, and PV, respectively for each of the circuits. Prosper circuit dairies were calculated separately for CHP because digesters would need to be installed and 50% of the fuel for generation would be from the ensuing methane production.

The allowance for EE technologies is greater for the Prosper circuit because of the abundance of agriculture and consequent opportunity for improved pumping efficiencies.

Table 20 – DE, EE and PV Allowances on Justice and Prosper Circuits

<table>
<tr><th colspan="4">Average Installation Allowances to meet 5-Year Paybacks</th></tr>
<tr><td>Circuit</td><td>CHP ($/kW)</td><td>EE ($/SF)</td><td>PV ($/kW)</td></tr>
<tr><td>Justice</td><td>900</td><td>3.9</td><td>1000</td></tr>
<tr><td>Prosper</td><td>900</td><td rowspan="2">7.4</td><td rowspan="2">1000</td></tr>
<tr><td>Prosper Dairies</td><td>5900</td></tr>
</table>

Figure 20 and Figure 21 together show how DE penetration would be reduced on the circuits if the capital costs for CHP installations were increased above the cost assumed in this study. The curves in Figure 20 are labeled according to the cost for a 1000 kW generator. Based on the cost curves established in Appendix B, a 1000 kW CHP system would cost $900/kW. A series of capital cost increases were analyzed, as reflected in Figure 20 (i.e. $1200, $1400 and $1700/kW for the 1,000 kW machine). These cost curves were applied to the equipment sizes selected in the initial analysis. Figure 21 shows the change in projected DG penetration on the 13 MW Justice circuit and 8 MW Prosper circuit as a function of DG system cost.

Figure 20 – Reduced Customer Adoption of DE Due to Increased DE Capital Costs (Part 1)

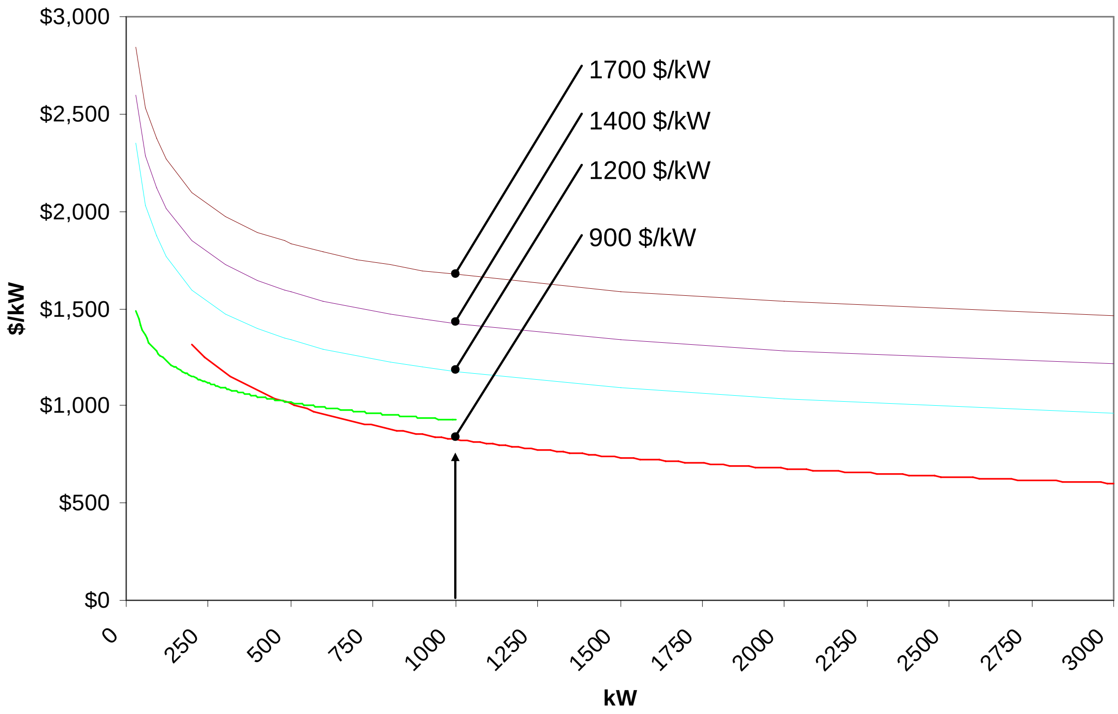
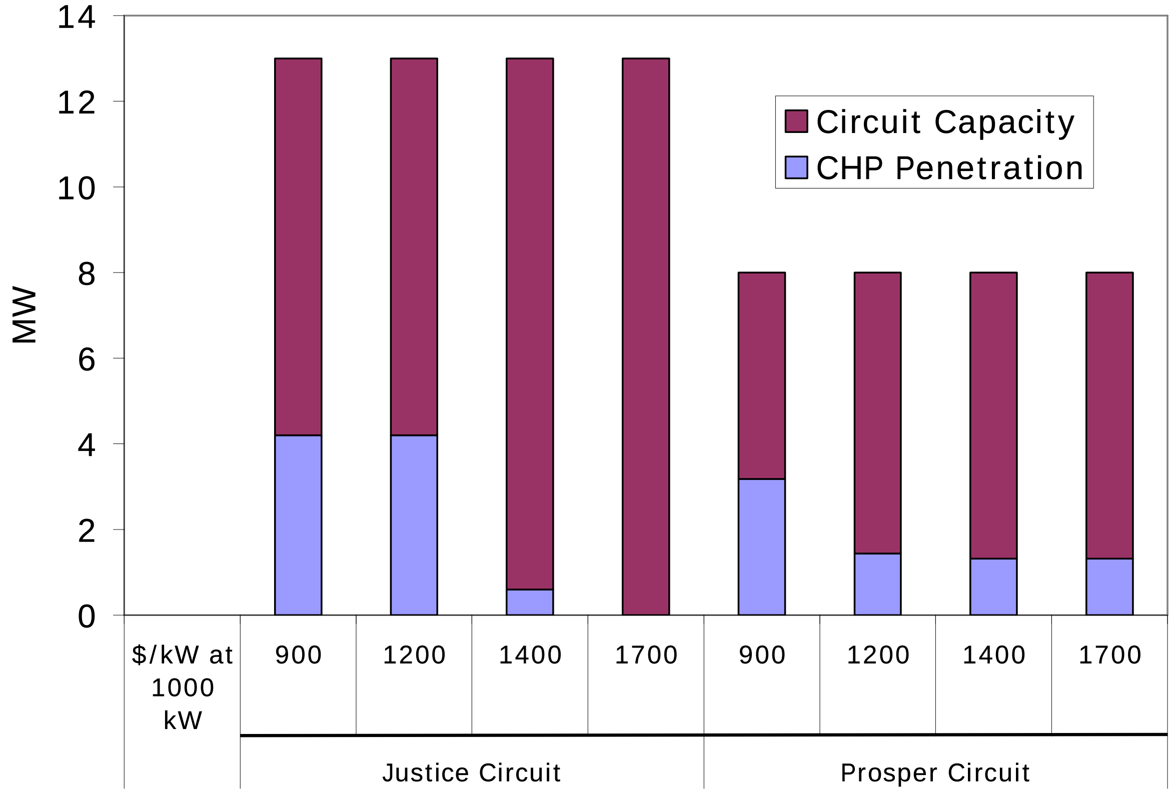


Figure 21 - Reduced Customer Adoption of DE Due to Increased DE Capital Costs (Part 2)



Gas and Electricity Inflation

Section Objective: Provide an account of gas and electricity rate changes between 2004 and 2005 and illustrate economic sensitivity to fluctuations in gas and electricity prices.

In April and July of 2005, SCE and Southern California Gas, respectively, made changes to their rates. The percent changes to the cost components are summarized in Table 21 and Table 22. These new rates had only minor effects on the paybacks and resulted in no change in DE penetrations on either of the circuits.

Table 21 – SCE 2005 Rate Changes

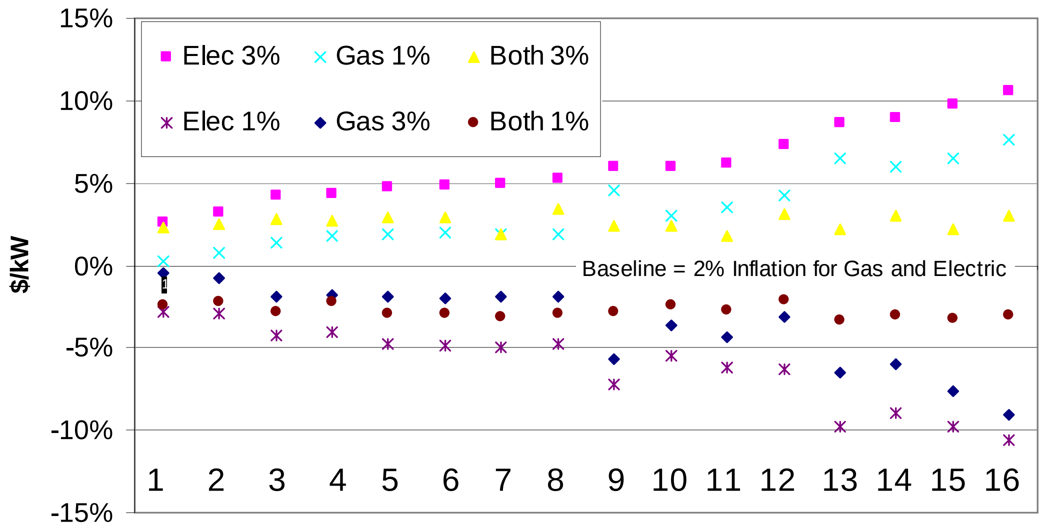
Electric	Energy		TOU Demand		Facilities
TOU-8	**Summer**	**Winter**	**Summer**	**Winter**	**Demand**
On Peak	-13%	+0%	+47%	+0%	+37%
Mid Peak	-10%	+2%	+48%	+0%	+37%
Off Peak	-36%	-35%	+0%	+0%	+37%
GS-2					
On Peak	+6%	+0%	+74%	+0%	+48%
Mid Peak	-10%	+6%	+74%	+0%	+48%
Off Peak	-39%	-37%	+74%	+0%	+48%

Table 22 – Southern California Gas 2005 Rate Changes

	Summer		Winter	
	Rate	**Cutoff**	**Rate**	**Cutoff**
Gas	$/Therm	Therms	$/Therm	Therms
Tier I	+18%	100	+18%	250
Tier II	+18%	4167	+18%	4167
Tier III	+15%	NA	+15%	NA

A separate analysis was done to further investigate the effects of energy inflation rates. The customer economic analysis was based on an assumption that both fuel and electricity prices would increase at a rate of 2%/year for the 10-year study period. A sensitivity study was made to examine the effects of variations in the fuel and electricity price inflation rates on typical building types. The installed DE system cost that would provide a five-year payback was used as a benchmark. As shown in Figure 22, variations of plus or minus 1% in the relative magnitude of these two inflation rates made a difference of up to 10% in the installed DE system cost for some smaller building types. For example, if gas prices inflate at the assumed rate of 2%, but electricity inflates at 3% rather than 2%, the DG system allowance could increase up to 10% for building types numbered 13-16. Likewise, if electricity prices inflate at the assumed rate of 2%, but the gas prices inflate at 3% rather than 2%, the DG system allowance could decrease as much as 10% for those same building types. However, considering the high proportion of gas-fired units in SCE's central generation portfolio, it is likely that the inflation rates for both electricity and natural gas will be very similar.

Figure 22 – Effects of Varying Gas and Electric Inflation Rates for 16 Building Types



Note: 2004 EIA Energy Outlook predicts 1% to 2% inflation for gas across the next ten years and 0.4% to 0.5% inflation for electric across the next ten years.

Building Number	Building Type
1	Refrigerated Warehouse
2	Industrial w/ Heat Demand
3	Hospital
4	School - Seasonal
5	High Rise Office
6	Large Hotel
7	School - Year-round
8	Industrial
9	Single Story Office
10	Small Hotel
11	Theatre
12	Nursing Home
13	Retail Store
14	Full Service Restaurant
15	Supermarket
16	Fast Food Restaurant

CONCLUSIONS

- California is pursuing an aggressive CHP, EE and renewables program to reduce peak electric demand, conserve energy, and provide clean local power production. Utilities in California can expect a significant impact on revenue due to continued growth in deployment of advanced technologies. Utility planners can look for the following confluence of factors to determine if customer- or utility-owned DE resources are the economic choice for circuit load relief:
    - Circuit will need expansion in three to five years.
    - Circuit expansion cost is above average.
    - Circuit peak load growth rate is fast.
    - Circuit is in a growth area where advanced energy technologies can be installed more cost effectively for new construction, which reduces load growth without reducing current revenue levels.
    - Circuit serves customers with significant thermal loads conducive to CHP.
    - Electric rates are higher than average, or higher than the cost to operate DE.
    - On-peak period is longer than eight hours so that shoulder demand is avoided.
- Using customer-owned advanced energy technologies on the Justice and Prosper circuits to defer circuit expansion could be an economical choice for SCE, depending on the marginal T&D upgrade cost estimates and the amount of load reduced on the circuit due to customer-owned technologies.
- SCE's historical data indicates that adding a 13 MW circuit to the Lincoln substation to relieve load on the Justice circuit, costs about $746,000 or $57/kW. Taking in account additional revenue from load growth and assuming a new circuit is needed, a capital investment of $746,000 for a new 13 MW circuit is the most economical long-term investment for the utility, if substantial deployment of customer-owned advanced energy technologies does not occur.
- If customers on the Justice and Prosper circuits install advanced energy technologies at capacities predicted in this study to be economical, SCE would incur substantial revenue loss. The losses would be compounded if the customers install the technologies and SCE installs an ultimately unnecessary circuit that effectively becomes a stranded asset.
- One of the premises of promoting customer-owned advanced energy technologies on selected circuits for load relief is that those circuits with the greatest upgrade costs would be chosen. This is especially important because transmission and distribution expansion cost estimates are reported to range from less than $100/kW to well over $3,000/kW.
- If a new 13 MW circuit that cost $2 million ($154/kW) or more is required to relieve load on the Justice circuit, customer-installed technologies could be an economical solution for SCE to defer the need for the new circuit. However, the amount of load reduction from the technologies must be considerably less (about 50% less) than the load reduction predicted in

this study. Furthermore, the deployment of the technologies must be gradual so that load reduction is at nearly the same pace as load growth.

- Through appropriate electricity price signals and targeted incentives, utilities could influence the amount of advanced energy technology deployed on selected circuits, thereby governing load reduction as necessary and economical.
- Transmission and distribution (T&D) capacity expansion investments may become stranded resources in the study area if moderate deployment of advanced energy technologies and the corresponding load reductions occur so that the capacity is not used.
- DE technologies alone or EE technologies alone could provide enough demand reduction to defer an upgrade to the Justice circuit. However, PV technologies alone would not provide enough demand reduction to defer an upgrade to Justice.
- DE technologies alone could provide enough demand reduction to defer an upgrade to the Prosper circuit. However, EE technologies alone or PV technologies alone would not provide enough demand reduction to defer an upgrade to Prosper.
- There are several factors that make DE resources an economic choice in this area. First, the utility rates are significantly greater than the operating cost of DE systems during on-peak periods. Second, the state of California offers significant incentives that effectively reduce the capital cost of installed DE resources. Third, the interconnection requirements are well established by California's Rule 21.
- The average installed cost allowance needed to attain a 5-year payback return for a typical CHP installation on both circuits is $900/kW. The generally higher average installation cost (roughly $1,300/kW after existing incentives) of the DE technologies considered in this study is the primary factor limiting greater customer adoption.
- If adding a 13 MW circuit to a substation costs about $746,000, as SCE's historical data indicates, the annual carrying cost would be $90,000/year with a 12% fixed charge rate. For the expected growth rate on the two circuits considered, this cost could be deferred for a year with a much smaller DE installation of less than 200 kW. Disregarding utility revenue growth, the utility's annual deferral cost would be more than $450/kW of installed DE.
- As required by the California PUC, SCE must issue an RFP for DE to meet capacity requirements at specified locations. If SCE sets the value of the deferral benefit at $400/kW of installed DE, the $1,300/kW installation cost used in this study would be reduced to $900/kW. The reduction would improve customer adoption of DE and provide SCE with greater possibilities for deferring the targeted circuit upgrades.
- There are several dairy farms on the Prosper circuit. The dairy economics, based upon California's incipient agricultural emissions regulations, are extremely favorable to DE. The emissions regulations can be met by using methane-producing digester systems that offset traditional fuel costs.
- For the average dairy farm on the Prosper circuit, a CHP/digester installation could cost up to $5,900/kW and still provide a 5-year payback. Dairy power projects have very good economic potential and could be environmentally beneficial. However, the market seems to be relatively untapped.

- A compelling economic case can be made for using utility-owned portable generation and energy storage devices to defer the two circuit upgrades.
- Thermostat setback and light dimming are two demand response strategies that could be viable options for locally targeted demand reduction (2% to 3% of peak demand) on the two circuits. These demand response strategies combined with others could be leveraged to manage up to 8% of the circuit peak load.
- Voltage flicker, one of the most significant concerns utilities have with respect to circuit reliability and power quality, would not be an issue with any of the proposed DE penetration scenarios on the Justice Circuit.
- The probability that two thirds of the proposed 4,200 kW of distributed generation in this study will be available from the CHP systems on the Justice circuit, is 98.6%.
- The average installed cost allowance to attain 5-year payback returns for EE installations on both circuits is between $\$3.9/ft^2$ and $\$7.4/ft^2$. The average premium for USGBC green buildings is $3/ft2 to $5/ft2.
- The average installed cost allowance needed to attain a 5-year payback return for a PV installation on both circuits is $1000/kW. The higher installation cost used for the study (i.e. $1,800/kW - including incentives) is the primary factor limiting greater customer adoption. Without incentives, the installation cost for PV is estimated to be $9,000/kW.
- The proposed California Air Regulatory Board (CARB) 2007 emissions requirements are causing concern among the DG community. Some reviewers contend that reciprocating engine systems, the dominant DE technology for installations smaller than 5 MW, will not be able to meet the proposed emissions requirements until 2010 and that the market penetration for such systems will therefore be negligible. However, other sources indicate that lean-burn engine systems are currently available that satisfy the CHP system emissions requirements, if not the power only requirements.
- Aggressive and innovative policies that California has implemented can increase the deployment of load-shaping technologies by influencing private investment. Those policies include:
    - Waiving standby charges for capacity-constrained areas of the system
    - Focusing incentives on capacity-constrained areas
    - Applying stepped demand charges or time-of-use rates that increase as load increases during the day.

RECOMMENDATIONS

Policy and Incentives

This study showed that advanced energy technologies are economical for many customers on the two SCE circuits analyzed, providing certain customers with considerable energy cost savings. Using reasonable assumptions about market penetration, the study showed that adding distributed generation would reduce peak demand on the two circuits enough to defer the need to upgrade circuit capacity. If the DE installations are optimally targeted, this deferral could economically benefit SCE, with cost savings that outweigh the lost revenues due to lower sales of electricity. To a lesser extent, economically justifiable energy-efficiency, photovoltaic technologies, and demand response could also help defer circuit capacity upgrades by reducing demand.

High electricity prices and state policy and incentives have already resulted in accelerated customer investment in advanced energy technology in California. Figure 23 and Figure 24 show how DE, EE, and PV technologies, if only deployed moderately on the SCE circuits within the next ten years, can greatly reduce peak loads. Demand response strategies, such as thermostat setback and light dimming, can be leveraged to further manage up to 8% of the circuit peak load.

Figure 23 – Overall Impact of DE, EE, and PV on the Justice Circuit

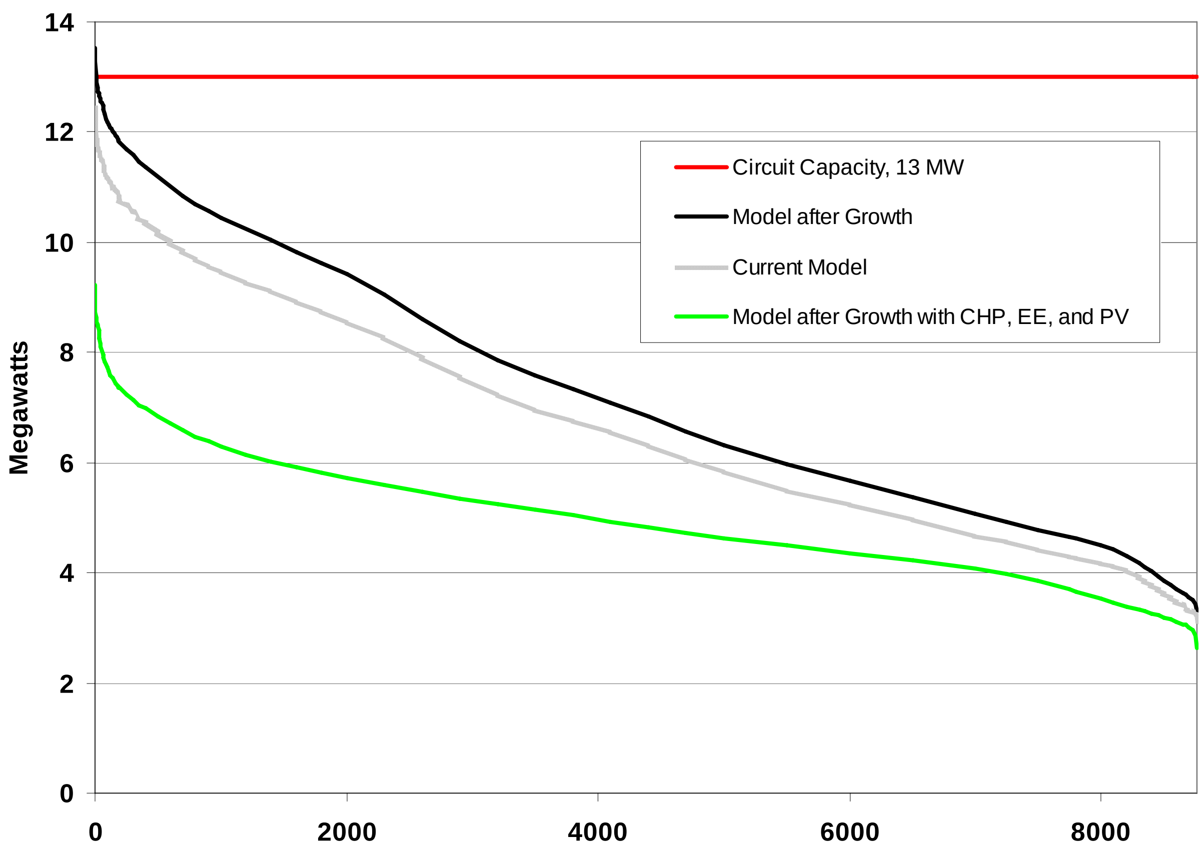
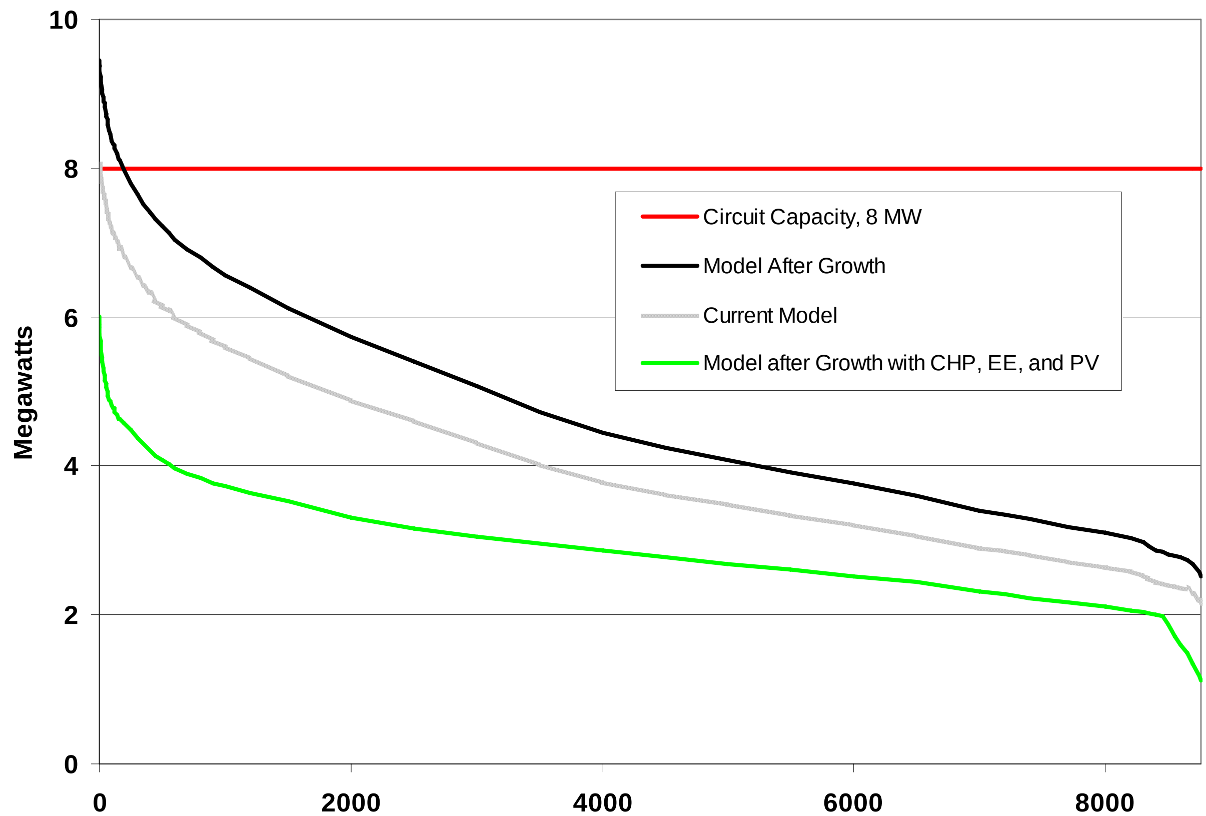
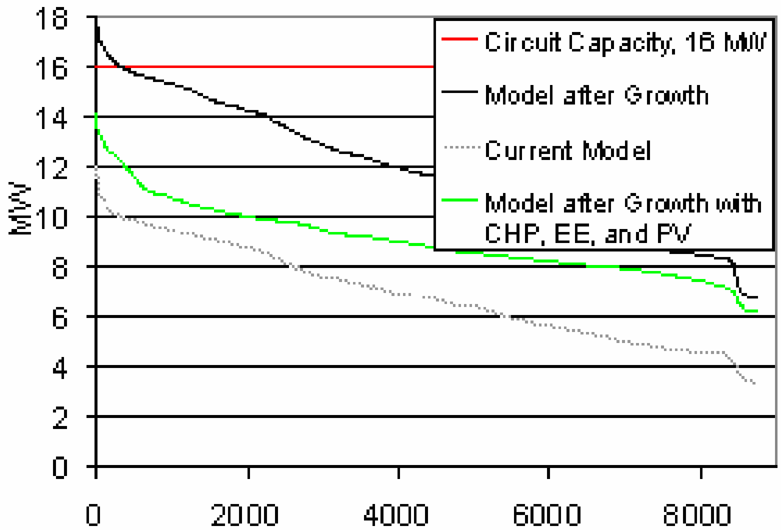


Figure 24 - Overall Impact of DE, EE, and PV on the Prosper Circuit



For circumstances of the SCE circuits, the combination of slow load growth and market-driven customer investment in advanced energy technologies could reduce existing electricity sales revenue. A desirable scenario for the utility would be to reduce the demand enough to defer circuit expansion, while maintaining existing energy sales. In contrast to the SCE circuits, the DTE circuit shown in Figure 25 had very fast load growth and customer investment in advanced energy technologies was predicted to be significantly lower, even when favorable business rules and market conditions were assumed. In this case, the circuit expansion could not be deferred and only future electricity sales revenue was impacted.

Figure 25 - Overall Impact of DE, EE, and PV on the DTE Suburban Circuit



Results from this study clearly reveal the potential for targeting private investment in technology with price signals and incentives on areas of the grid that will become constrained due to electric load growth. Utilities and policy makers could influence the amount of DE, EE, and PV that is deployed on selected circuits and tailor ideal scenarios where the load reduction is sufficient to defer circuit expansion without an excessive reduction in overall energy sales.

Optimization

This study shows that electricity rates, incentives, and policy can have significant impacts on customer investment in advanced energy technologies. Future research is required to optimize electricity rate structures and develop new policy that improves market penetration in targeted areas where load relief is needed most and subsidies are best spent. This could include sensitivity on time-of-use rates, extended payback periods based on utility ownership, waiving standby charges, special gas rates, targeted incentives, etc.

Timing the Circuit

For both of the GTI case studies commissioned by DOE (this study with SCE and the previous study with DTE), the utility took steps to relieve the immediate risk of overloading before the study results were complete. It is clear that DE efforts must begin producing significant results long before system capacity constraints become urgent issues. A major lesson learned during these two studies is that we must look further out in time in making these assessments. Installing DE requires some time to cover the stages of assessment, design, and installation. The utility would probably also require that the DE be commissioned and run for some minimum length of time before the utility could have sufficient confidence in that resource to defer a circuit modification. Considering these factors, we should select circuits that are projected to need expansion in the three- to five-year time frame (rather than one year or less) so that DE alternatives can effectively compete with the more traditional solutions.

Analysis Methodology

These circuit analyses have been based on a methodology of summing up the hourly results of individual building models. This holistic methodology permits the consideration of DE, energy-efficiency, and photovoltaics for every customer. Given that these studies have shown that the lion's share of the potential load relief is concentrated within a limited number of customers, an alternate method which models only these customers would be more efficient. This alternate method would only be possible if the hourly data were available for both the circuit and the larger customers. Otherwise, the degree to which the building load reductions are coincident with the diversified circuit peak loads would be unknown, and the modeled capacity relief could be inflated. This method requires the analyst to pre-select the customers that are the best candidates, so some opportunities may be missed.

Improving Voltage Support

Further analysis is required to determine if DE systems can improve reliability from a voltage standpoint while avoiding over-aggressive tripping that makes the bulk distribution system vulnerable to voltage collapse. The Distributed Energy Workstation could be used to model voltages on circuits and substations with various degrees of DE adoption. Further analysis is also required to determine the effects of single-mode-failures that can trip off multiple DE systems simultaneously.

Amend Rule 21 to Adopt a Preliminary Conceptual Review of DE Projects

The group of DE developers that reviewed California's interconnection Rule 21 found that the greatest opportunity, from a DE developer's standpoint, to streamline the interconnection process while maintaining utility system security is to add a preliminary conceptual review. In theory, the developer would prepare a preliminary conceptual review application that provides the utility with information such as building address, meter numbers, and generator details (See Appendix F for an example Application Form). In return, the utility would provide the developer with basic interconnection characteristics and anticipated requirements that could help define the risk associated with the project.

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NOTES

i. DECP is an investment program that leverages gas and electric utility resources to promote the development of advanced energy systems. Current members include AEP, Alagasco, California Energy Commission, City Public Service San Antonio, Keyspan Energy, Memphis Light Gas and Water, Public Gas Investment Pool and Questar.

ii. The radial system is analogous to a wheel with spokes emanating out from the center. Main power is delivered to a central point, and from there is divided on series branch circuits to supply services to individual customers.

iii. Building Energy Analyzer provides 8,760 hour (one year) electric and gas load profiles and life-cycle economic analysis for energy applications in commercial and industrial buildings. It uses the DOE 2.1E computational engine to calculate building energy load profiles.

iv. Several techniques are used in Building Energy Analyzer to calibrate building models against real data. These techniques can be found in Appendix G.

v. Customers can qualify for the utility RFP if the proposed DE system provides enough load relief for the utility to avoid transmission and distribution cost. It requires physical assurance that forces the customer to either bring the DE up or drop load when the utility requests. The RFP is valued at roughly 10% of the utility-avoided investment in transmission and distribution.

vi. Time-discounted payback period is calculated based on a life cycle cost analysis considering depreciation, O&M, fuel costs, interest rates, cost of capital, income tax, and inflation (see Appendix H for details)

vii. Building Energy Analyzer generates categorized annual kWh consumptions for lighting, fans and pumps, and HVAC. The categorized kWh values were used to determine how much EE incentive to apply to the building EE economics.

viii. Building Energy Analyzer models PV electricity production accounting for panel tilt, azimuth, incident solar radiation, etc. The panels were modeled at the same tilt as the roof pitch. The rated capacity, or “max kW”, is therefore only produced for a fraction of the time. The BEA does not derate the PV capacity as the panels age, but holds it constant over the 10-year study period.

ix. Integrated demand reductions for the combined DE, EE, and PV models are not equal to the sum of the demand reductions for the individual DE, EE, and PV models because of the interrelationships between the loads and the energy sources. For example, when EE and PV technologies are implemented, DE resources do not have to supply as much electric demand and therefore, demand reductions are less.

x. Annual fixed charge rate is a factor used to annualize equipment fixed cost as a function of:

a. Cost of capital
b. Return of capital
c. Depreciation
d. Taxes
e. Insurance

APPENDICES

Appendix A –Customers with Demands > 100 kW

SUBSTATION	CIRCUIT	SEGMENT	ANNL MAX KW	ANNL KWH
Lincoln	Liberty	SCHOOLS	851	2136788
Lincoln	Liberty	NO SIC CODE	717	863
Lincoln	Liberty	WATER AGENCIES	201	1095454
Lincoln	A	WATER AGENCIES	590	747217
Lincoln	A	WATER AGENCIES	462	1452169
Lincoln	A	FOOD STORES/REFRIG WAREHOUSES	286	1902072
Lincoln	A	WATER AGENCIES	256	187638
Lincoln	A	HOTELS & MOTELS	131	521280
Lincoln	A	RETAIL STORES/LARGE & SMALL	104	474888
Lincoln	B	SCHOOLS	353	672950
Lincoln	C	SCHOOLS	344	664746
Lincoln	C	ALL OTHER INDUSTRIAL	321	1620997
Lincoln	C	ALL OTHER COMMERCIAL	271	207480
Lincoln	C	ALL OTHER COMMERCIAL	141	120300
Lincoln	C	ALL OTHER COMMERCIAL	121	85320
Lincoln	D	FOOD STORES/REFRIG WAREHOUSES	362	2212651
Lincoln	D	OFFICE BUILDINGS/LARGE & SMALL	354	1226843
Lincoln	D	FOOD STORES/REFRIG WAREHOUSES	254	1545491
Lincoln	D	CHEMICALS & ALLIED PRODUCTS	252	554475
Lincoln	D	HOSPITALS/MEDICAL FACILITIES	236	1073456
Lincoln	D	ALL OTHER COMMERCIAL	210	124120
Lincoln	D	WATER AGENCIES	199	539313
Lincoln	D	COMPUTERS/ELECTRONICS/PLATING	166	671820
Lincoln	E	OFFICE BUILDINGS/LARGE & SMALL	801	39591
Lincoln	E	WATER AGENCIES	421	1007079
Lincoln	E	ALL OTHER COMMERCIAL	149	631680
Lincoln	E	ALL OTHER COMMERCIAL	140	498960
Lincoln	F	SCHOOLS	312	451441
Lincoln	Justice	ALL OTHER COMMERCIAL	1168	3157080
Lincoln	Justice	ALL OTHER INDUSTRIAL	701	1292370
Lincoln	Justice	BUILDERS: RES & COMML	590	1835805
Lincoln	Justice	OTHER WAREHOUSES	527	1589147
Lincoln	Justice	OFFICE BUILDINGS/LARGE & SMALL	335	363206
Lincoln	Justice	ALL OTHER COMMERCIAL	330	1120789
Lincoln	Justice	ALL OTHER INDUSTRIAL	321	965315
Lincoln	Justice	OFFICE BUILDINGS/LARGE & SMALL	317	1029996

Lincoln	Justice	PRINTING & PUBLISHING	302	810195
Lincoln	Justice	ALL OTHER COMMERCIAL	259	1191244
Lincoln	Justice	COMPUTERS/ELECTRONICS/PLATING	253	525500
Lincoln	Justice	OTHER WAREHOUSES	249	1269870
Lincoln	Justice	OTHER WAREHOUSES	228	772143
Lincoln	Justice	FURNITURE & FIXTURES	211	466800
Lincoln	Justice	NONMETALLIC MINERALS & PRODS	198	346052
Lincoln	Justice	CHEMICALS & ALLIED PRODUCTS	197	621310
Lincoln	Justice	ALL OTHER COMMERCIAL	192	352680
Lincoln	Justice	HOTELS & MOTELS	157	193598
Lincoln	Justice	ALL OTHER COMMERCIAL	148	333360
Lincoln	Justice	OTHER WAREHOUSES	134	3600
Lincoln	Justice	OTHER WAREHOUSES	102	155220
Lincoln	G	ALL OTHER COMMERCIAL	251	146700
Lincoln	G	SCHOOLS	178	291600
Lincoln	G	OFFICE BUILDINGS/LARGE & SMALL	138	311760
Lincoln	G	RESTAURANTS	119	393061
Lincoln	H	FOOD STORES/REFRIG WAREHOUSES	332	2178518
Lincoln	H	SCHOOLS	185	103665
Lincoln	H	SCHOOLS	184	197220
Lincoln	H	RETAIL STORES/LARGE & SMALL	161	423120
Lincoln	H	RESTAURANTS	161	765890
Lincoln	H	RETAIL STORES/LARGE & SMALL	133	631320
Lincoln	H	OFFICE BUILDINGS/LARGE & SMALL	122	246180
Lincoln	H	WATER AGENCIES	110	95200
Lincoln	H	OFFICE BUILDINGS/LARGE & SMALL	101	215940
Lincoln	I	WATER AGENCIES	994	2660221
Lincoln	I	WATER AGENCIES	436	610086
Lincoln	I	SCHOOLS	430	864533
Lincoln	I	SCHOOLS	217	322277
Lincoln	I	ALL OTHER COMMERCIAL	160	625380
Lincoln	J	NO SIC CODE	107	406650
Jefferson	Freedom	AGRICULTURE	352	1698848
Jefferson	Freedom	AGRICULTURE	188	969209
Jefferson	Freedom	AGRICULTURE	156	857362
Jefferson	Freedom	AGRICULTURE	151	179360
Jefferson	Freedom	UNCLASSIFIED/YET TO BE CLASSIF	140	135600
Jefferson	Freedom	AGRICULTURE	139	144620
Jefferson	Freedom	AGRICULTURE	132	227346
Jefferson	Freedom	AGRICULTURE	130	360520
Jefferson	Freedom	AGRICULTURE	124	274325

Jefferson	Freedom	AGRICULTURE	123	40566
Jefferson	Freedom	AGRICULTURE	121	328859
Jefferson	Freedom	AGRICULTURE	120	270236
Jefferson	Freedom	AGRICULTURE	114	582520
Jefferson	Freedom	AGRICULTURE	113	623040
Jefferson	Freedom	AGRICULTURE	106	271080
Jefferson	Freedom	AGRICULTURE	103	283154
Jefferson	Freedom	AGRICULTURE	101	248853
Jefferson	Freedom	AGRICULTURE	101	148989
Jefferson	Freedom	AGRICULTURE	101	255877
Jefferson	Y	SCHOOLS	212	359502
Jefferson	Y	NONMETALLIC MINERALS & PRODS	164	438960
Jefferson	Y	RETAIL STORES/LARGE & SMALL	108	224640
Jefferson	Z	AGRICULTURE	1045	1641210
Jefferson	Z	AGRICULTURE	311	1399908
Jefferson	Z	AGRICULTURE	159	397999
Jefferson	Z	AGRICULTURE	156	297960
Jefferson	Z	AGRICULTURE	130	297324
Jefferson	Z	AGRICULTURE	118	274320
Jefferson	Z	AGRICULTURE	118	484320
Jefferson	Z	AGRICULTURE	113	94597
Jefferson	Z	AGRICULTURE	106	74640
Jefferson	Z	AGRICULTURE	103	148222
Jefferson	Z2	WATER AGENCIES	848	4655611
Washington	Prosper	FOOD STORES/REFRIG WAREHOUSES	1684	9249380
Washington	Prosper	AGRICULTURE	700	1975625
Washington	Prosper	AGRICULTURE	292	1075598
Washington	Prosper	AGRICULTURE	203	385999
Washington	Prosper	AGRICULTURE	182	495971
Washington	Prosper	AGRICULTURE	182	27648
Washington	Prosper	AGRICULTURE	159	450176
Washington	Prosper	FOOD STORES/REFRIG WAREHOUSES	151	600298
Washington	Prosper	AGRICULTURE	124	160920
Washington	Prosper	AGRICULTURE	122	240350
Washington	Prosper	AGRICULTURE	110	509800
Washington	Prosper	AGRICULTURE	109	426141
Washington	Prosper	SCHOOLS	108	183280
Washington	Prosper	ALL OTHER COMMERCIAL	106	250400
Washington	Prosper	AGRICULTURE	104	487920
Washington	N	FOOD STORES/REFRIG WAREHOUSES	376	2122918
Washington	N	FOOD STORES/REFRIG WAREHOUSES	334	2103746

Washington	N	SCHOOLS	214	417303
Washington	N	WATER AGENCIES	210	643322
Washington	N	WATER AGENCIES	209	846838
Washington	N	RETAIL STORES/LARGE & SMALL	206	605460
Washington	N	ALL OTHER COMMERCIAL	203	44820
Washington	N	RETAIL STORES/LARGE & SMALL	135	420300
Washington	N	RESTAURANTS	132	454650
Washington	N	RETAIL STORES/LARGE & SMALL	119	479340
Washington	N	RETAIL STORES/LARGE & SMALL	116	438915
Washington	N	RETAIL STORES/LARGE & SMALL	111	515040
Washington	O	RETAIL STORES/LARGE & SMALL	139	202200
Washington	O	ALL OTHER COMMERCIAL	116	8191
Washington	O	ALL OTHER COMMERCIAL	104	204060
Washington	O	RESTAURANTS	101	488844
Washington	D	FOOD STORES/REFRIG WAREHOUSES	198	1231380
Washington	D	WATER AGENCIES	188	121380
Washington	D	WATER AGENCIES	186	1074856
Washington	D	SCHOOLS	144	290160
Washington	D	ALL OTHER COMMERCIAL	142	94960
Washington	D	RETAIL STORES/LARGE & SMALL	113	556620
Washington	D	FOOD & KINDRED PRODUCTS	106	104720
Washington	Q	AGRICULTURE	1960	2123301
Washington	Q	AGRICULTURE	1309	1469781
Washington	Q	WATER AGENCIES	400	2692146
Washington	Q	FOOD & KINDRED PRODUCTS	205	1109440
Washington	Q	ALL OTHER COMMERCIAL	162	18360
Washington	Q	WATER AGENCIES	155	691673
Washington	Q	WATER AGENCIES	130	323389
Washington	Q	WATER AGENCIES	128	189960
Washington	Q	SCHOOLS	123	179840
Washington	Q	NONMETALLIC MINERALS & PRODS	122	158520
Washington	Q	SCHOOLS	118	86340
Washington	Q	AGRICULTURE	117	80856
Washington	Q	AGRICULTURE	114	422766
Washington	Q	FOOD & KINDRED PRODUCTS	111	217480
Washington	Q	AGRICULTURE	106	177720
Washington	Q	OFFICE BUILDINGS/LARGE & SMALL	106	591780
Washington	Q	ALL OTHER COMMERCIAL	103	20560
Washington	R	FOOD STORES/REFRIG WAREHOUSES	326	1810433
Washington	R	AGRICULTURE	276	223840
Washington	R	PETROLEUM REFINING	276	1019621

Washington	R	AGRICULTURE	186	126900
Washington	R	SCHOOLS	175	417000
Washington	R	SCHOOLS	163	331080
Washington	R	FOOD & KINDRED PRODUCTS	160	97980
Washington	R	AGRICULTURE	133	654475
Washington	R	SCHOOLS	126	146400
Washington	R	WATER AGENCIES	122	399900
Washington	R	OFFICE BUILDINGS/LARGE & SMALL	112	185920
Washington	R	AGRICULTURE	107	405754
Washington	R	WATER AGENCIES	101	39540
Washington	T	RETAIL STORES/LARGE & SMALL	160	4600
Washington	T	ALL OTHER COMMERCIAL	114	17448
Washington	V	SCHOOLS	252	388288
Washington	V	HOSPITALS/MEDICAL FACILITIES	228	952636
Washington	V	WATER AGENCIES	211	954673
Washington	V	ALL OTHER COMMERCIAL	183	734630
Washington	V	WATER AGENCIES	146	147160
Washington	V	PRINTING & PUBLISHING	144	403500
Washington	V	HOSPITALS/MEDICAL FACILITIES	124	276180
Washington	V	RETAIL STORES/LARGE & SMALL	114	354840
Washington	V	AGRICULTURE	108	1932
Washington	W	RETAIL STORES/LARGE & SMALL	910	3219740
Washington	W	FOOD STORES/REFRIG WAREHOUSES	872	5536904
Washington	W	RETAIL STORES/LARGE & SMALL	578	3289064
Washington	W	RETAIL STORES/LARGE & SMALL	561	2225977
Washington	W	FOOD STORES/REFRIG WAREHOUSES	323	1875051
Washington	W	RETAIL STORES/LARGE & SMALL	306	1179714
Washington	W	RETAIL STORES/LARGE & SMALL	300	1055047
Washington	W	RETAIL STORES/LARGE & SMALL	241	839541
Washington	W	FOOD STORES/REFRIG WAREHOUSES	233	1510988
Washington	W	RETAIL STORES/LARGE & SMALL	181	593440
Washington	W	PRIMARY & FABRICATED METALS	167	18379
Washington	W	SCHOOLS	138	202960
Washington	W	RETAIL STORES/LARGE & SMALL	136	475680
Washington	W	HOSPITALS/MEDICAL FACILITIES	118	378280
Washington	W	RESTAURANTS	116	444000
Washington	W	SCHOOLS	116	95720
Washington	W	RETAIL STORES/LARGE & SMALL	107	330480
Washington	W	OFFICE BUILDINGS/LARGE & SMALL	104	300000
Washington	X	HOSPITALS/MEDICAL FACILITIES	427	2154840
Washington	X	SCHOOLS	306	609144

Washington	X	HOSPITALS/MEDICAL FACILITIES	180	466380
Washington	X	SCHOOLS	173	296520
Washington	X	AGRICULTURE	166	736304
Washington	X	ALL OTHER COMMERCIAL	165	36480
Washington	X	SCHOOLS	107	197640
Washington	X	ALL OTHER COMMERCIAL	101	30240
Washington	K	OFFICE BUILDINGS/LARGE & SMALL	2218	7446260
Washington	K	SCHOOLS	747	1940236
Washington	K	HOSPITALS/MEDICAL FACILITIES	635	3421411
Washington	K	OFFICE BUILDINGS/LARGE & SMALL	358	1691330
Washington	K	RETAIL STORES/LARGE & SMALL	346	940440
Washington	K	RETAIL STORES/LARGE & SMALL	325	1773197
Washington	K	FOOD & KINDRED PRODUCTS	304	1274858
Washington	K	AGRICULTURE	215	202537
Washington	K	SCHOOLS	214	328580
Washington	K	HOSPITALS/MEDICAL FACILITIES	149	505080
Washington	K	ALL OTHER COMMERCIAL	124	57540
Washington	K	OFFICE BUILDINGS/LARGE & SMALL	122	244320
Washington	K	OFFICE BUILDINGS/LARGE & SMALL	113	43687
Washington	K	HOSPITALS/MEDICAL FACILITIES	106	373840
Washington	L	SCHOOLS	614	1381706
Washington	L	SCHOOLS	191	212820
Washington	L	SCHOOLS	182	213520
Washington	L	RETAIL STORES/LARGE & SMALL	117	269360
Washington	M	SCHOOLS	286	567902
Washington	M	COMMUNICATIONS	192	918223
Washington	M	ALL OTHER COMMERCIAL	113	265920

Appendix B – Assumptions

General Assumptions

Assumption	Comments
Macroeconomic	
Electricity and Natural Gas Inflation is 2%/year.	
All financial calculations are in 2004 dollars.	
California	
California Public Utility Commission Self-Generation Program is available.	Level 3-N (30% reduction in first-cost) applies to DE technologies. Level 1 ($4.5/watt) applies to PV technologies.
California Public Utility Commission Standard Performance Contract Program is available.	The following rebates are available to EE technologies: Lighting = $0.05/kWh saved Motors and other Equipment = $0.08/kWh saved AC and Refrigeration = $0.14/kWh saved Natural Gas = $1.00/therm saved
California Energy Commission Emerging Renewables Program is available.	Photovoltaic rebate ($3.2/watt) applies to PV technologies.
California Energy Commission Dairy Power Production Program is available.	Grants reduce first-cost by 50% for dairy farm CHP/digester installations.
DE installations are exempt from standby and generation reservation charges.	To account for the cost of DE downtime, a standby charge is implemented in analyses, despite the fact that SCE waives standby charges. The standby charge is set at the facility demand charge, but is proportionally reduced for cases where multiple DE machines are modeled for facility generation.
SCE	
SCE Generation Mix: 14% coal; 20% nuclear; 3% Hydroelectric; 44% Natural Gas; 19% renewables.	Values are from 2005 SCE Power Content Label.
Per CPUC SCE can own DG as long as it is reasonable and prudent.	
Technology and Modeling	
Circuit Load data available for time-of-use customers only.	
Only non-residential customers are included in circuit models.	

Facilities with hot water demands can meet all or a portion of the demands with hot water recovered from CHP systems.	
2004 circuit status remains unchanged throughout the duration of the project.	It is assumed that the 3,714 kW industrial facility on Justice was not transferred to an adjacent circuit.
DE systems are configured to run during mid- and on-peak times only.	With the use of methane, the cost to fuel CHP systems is less than off-peak electricity prices. Therefore, DE systems at dairy farms are configured to run full time.
Natural gas is available at all customer sites.	
Circuit load data provided by SCE is specific to 2004.	
Circuit models are based on TMY2 weather data.	
Distributed energy technology cost & performance are at 2004 levels.	
Portable utility-owned natural gas-fired power generation is allowable.	
Diesel-fueled system runtime is limited to less than 200 hours per year for emergency purposes only (grid power must be unavailable).	Utilities in California are restricted from using diesel generation for grid support.
CHP systems achieve a minimum efficiency of 60% (useful energy out/fuel in).	The efficiency determination is based on 100% load.
DE technologies are sized and modeled in configurations that offer the best time-discounted payback periods.	
CHP systems recover heat to domestic hot water, space heating (if applicable) and absorption cooling.	Utility installed DG does not account for heat recovery.
Power generators are configured to track electric load.	
Fluorescent lighting requires 40% less watts/ft^2 than typical incandescent.	
Maximum light dimming capability is 33%.	
High performance pumping is 10% more efficient than typical pumping.	
Renewable energy technology is defined as a system fueled by solar, wind, or gas derived from biomass, digester gas, or landfill gas.	A facility using a renewable fuel may not use more than 25% fossil fuel annually, as determined on a total annual energy input basis.
Circuit impact models are based on technologies being installed between 2005 and 2015.	
Engine **maximum** efficiencies are: < 900 kW: Electric = 34%, Total = 76% > 900 kW: Electric = 35%, Total = 77%	 Jacket water temp = 215 F, Exhaust temp = 900 F Jacket water temp = 235 F, Exhaust temp = 850 F
Microturbine **maximum** efficiencies are:	

Electric = 28%, Total = 78%	Exhaust temp = 540 F
PV performance: Power = 10 W/ft^2 Panel tilt = 45 deg Panel azimuth = East Power Coefficient = 0.5%/F Rating point temp = 77 F Nominal operating temp = 115 F Inverter efficiency: 90%	
Energy Storage: Lead acid battery charging efficiency: 75%	

Customer Assumptions

Assumption	Comments
General	
10-year study period.	
Value of Service	
Customers are motivated by ancillary benefits but ancillary benefits will not effect customer adoption (penetration). Penetration of technologies is based solely on discounted payback periods- "green values" are not monetized.	No extra revenue for the sale of green power certificates.
DE Availability is 96% to 98% annually.	
Decision Making Tools	
Commercial, industrial, institutional customer payback is calculated and used to determine penetration.	Time-discounted paybacks were used to determine penetration.
Customer adoption rates are based on the National Energy Modeling System.	
Financial	
Installed cost for engines is defined by: Y = 6067.1X^-0.2885, where X = kW	The cost equation describes rich- and lean-burn engines with BACT emissions control and 30% reduction in total cost for California incentives. The cost does not include an Absorption chiller. (e.g. a 500 kW engine would cost $1010/kW or $1313/kW without incentives).
O&M cost for engines is $0.01155/kWh	
Installed cost for microturbines is defined by: Y = 2366.8X^-0.136, where X = kW	The cost equation includes a 30% reduction in total cost for California incentives. The cost does not include an Absorption chiller. (e.g. a 30 kW microturbine would cost $1490/kW or $1937/kW without incentives).
O&M cost for microturbines is $0.0105/kWh	
Installed cost for absorption chillers is defined by: Y = 2036X^-0.1473, where X = refrigeration tons	This installed cost is added to the cost of engines or microturbines for CHP applications where absorption chillers were applied.
O&M cost for absorption chillers is defined by: Y = 644.61X^-0.8454, where X = refrigeration tons	

Lead Acid battery systems (LABS) installed cost is $1800/kW.	Installed cost is based on a five-hour discharge period and a 12-year life span. The cost does not reflect incentives.
LABS O&M cost is $15/kW-yr	
Energy-Efficiency measures cost $4/ft^2.	This cost is based on USGBC certified green-building premiums of $3/ft^2 to $5/ft^2.
Installed cost for photovoltaics is $1800/kW.	The cost reflects incentives. Without incentives the installed cost of PV is $9500/kW.
Cost of capital is 12% per year.	
Finance period is 10 years.	
Projects are 50% financed.	
Tax Rate is 15% and method is straight line.	
Finance interest rate is 7%.	
Interconnection	
Interconnection costs are included in installation cost.	
Biopower Production	
1 Dairy cow = 100 watts of potential dairy power	
Dairy farms that install CHP will also install waste digesters	
Digester biogas elminates 50% of the fuel cost for power generation at dairies	50% of the digester sludge-heating requirement is met by CHP.
DE systems at dairy farms are configured to run full time.	
Installed cost for dairy farm CHP systems with digesters is defined by: Y = 5.028X + 2775, where X = kW between 30 kW and 360kW	The cost equation includes a 50% reduction in total cost for California incentives. The cost does not include an Absorption chiller.
Photovoltaics	
PV panels cover 50% of the roof space for buildings on the Justice circuit	
PV panels cover 25% of the roof space for buildings on the Prosper circuit	

Utility Assumptions

Assumption	Comments
Electric System	
Upgrade factor for T&D = 50%	
Reliability of electric service is 99.98%.	
Justice circuit load growth is 1.3% per year.	
Justice circuit capacity is 13 MW	
Prosper circuit load growth is 1.6% per year.	
Prosper circuit capacity is 8 MW	
Justice Impedances: Thevinin equivalent looking back into the transmission system: Positive sequence = 0.00390 + j 0.06309 Impedance of the substation transformer: Positive sequence = 0 + j 0.23822	Values used for flicker analysis. Values on a 100 MVA base (positive sequence)
Financial	
Electricity rates increases in 2005	
Cost of T&D upgrade $740,762 and $750,500	Historical values from SCE for two different 13 MW circuits.
Utility pay-outs for demand response $85/kW	
Fixed rate charge is 12% for the utility to own distributed resources	Factor used to annualize total costs.
Locational marginal pricing not offered	Potential research for implementation plan
Real time/dynamic pricing not offered	Potential research for implementation plan
Current authorized cost of capital is 9.75% and SCE has requested 9.2% for 2005. SCE marginal cost of capital is 10.5%	
Frequency of rate case is 3 years	Rate reviews are scheduled to take place every 3 years (3 utilities, 1 every year).
Utility allowed to own, operate, and earn returns on DG (rate based)	$8000 per month to over $15000 per month for rental costs
Utility distributed generation ownership on customer sites allowed (on utility meter side)	
Utility can contract with customer for distributed generation benefits	Possible, but not done frequently.
Net metering is allowed for units below 2000 kW	
Distributed Generation	
CHP is not an option for utility	There will seldom be a corresponding thermal load.

Incentives do not apply to utility DG	

Technology Assumptions

Technologies Considered	*Comments*
Distributed Energy Technologies	
Microturbines	
Reciprocating Engines	
Combined Heat and Power	Used only by customers, not utility DG
Electric Storage	Lead acid batteries
Renewable Energy Technologies	
Photovoltaics	
Biopower	
Energy Efficient Technologies	
Demand Response	Light dimming and thermostat setback
High performance HVAC	Variable speed drives for chillers, fans and pumps Variable air volume control No HVAC system oversizing
High-performance Lighting	
High-performance windows	
High-reflectance roof material	

Technologies not Considered	*Comments*
Wind Turbines	Wind power was not included on the technologies list because it is not a technology that can be feasibly implemented in the SCE regions of the study.
Solar Heating	Solar heating was not included on the technologies list because the study areas do not have large heating demands.
Sterling Engines	Considered future technologies and will not be included in the list of technologies.
Organic Rankine Cycle	Considered future technologies and will not be included in the list of technologies.

Flared Fuels from landfill	Flared fuels from landfills were discussed as a renewable technology option, but landfills do not exist on these particular circuits.
Geothermal Heat Pumps	Geothermal pumps are typically used for new construction. Additionally there is little heating demand in the study area.
Fuel Cells	Installed costs for fuel cells are too high for this study

Utility Rate Schedules

Time of Use Schedule

Summer Hour of the day

Weekdays	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
On Peak																								
Mid Peak																								
Off Peak																								
Weekends																								
Off Peak																								

Winter Hour of the day

Weekdays	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Mid Peak																								
Off Peak																								
Weekends																								
On Peak																								

Rate Season

Winter: October to May
Summer: June to September

	TOU-8		**GS-2**	
	URG	**DWR**	**URG**	**DWR**
Demand Qualifications	>500 kW	>500 kW	<500 kW	<500 kW
Monthly Charge ($/mo)	$298.65	$298.65	$60.30	$60.30
Tax, Surcharges (%)	7%	7%	7%	7%
Schedule S Standby ($/kW)	$6.77	$6.77	$6.77	$6.77

	Energy		**TOU Demand**		**Facilities**
TOU-8 URG	**Summer**	**Winter**	**Summer**	**Winter**	**Demand**
On Peak	$0.15110	$0.00000	17.55	0.00	6.40
Mid Peak	$0.06966	$0.08163	2.80	0.00	6.40
Off Peak	$0.05030	$0.05132	0.00	0.00	6.40
TOU-8 DWR					
On Peak	$0.10529	$0.00000	17.55	0.00	6.40
Mid Peak	$0.10529	$0.10529	2.80	0.00	6.40
Off Peak	$0.10529	$0.10529	0.00	0.00	6.40
GS-2 URG					
On Peak	$0.16135	$0.00000	7.75	0.00	5.40
Mid Peak	$0.09992	$0.10881	7.75	0.00	5.40
Off Peak	$0.08253	$0.08253	7.75	0.00	5.40
GS-2 DWR					
On Peak	$0.10697	$0.00000	7.75	0.00	5.40
Mid Peak	$0.10697	$0.10697	7.75	0.00	5.40
Off Peak	$0.10697	$0.10697	7.75	0.00	5.40

Charges: All rates are based on power supplied at the lowest utility supply voltage.

Emissions for Regional Utility Generation Mix

	2003 CARB Regulations DG Lbs/MWh	2003 CARB Regulations CHP Lbs/MWh	2007 CARB Regulations DG Lbs/MWh	2007 CARB Regulations CHP Lbs/MWh	eGrid 2002 California Utility Mix Lbs/MWh	eGrid 2002 WECC Utility Mix Lbs/MWh
CO2	N/A	N/A	N/A	N/A	633.06	1014.46
CO	6.0	6.0	0.10	0.10		
SO2	N/A	N/A	N/A	N/A	0.17	1.54
NOx	0.5	0.7	0.07	0.07	0.56	1.78
VOCs	1.0	1.0	0.02	0.02		

WECC Western Electric Coordinating Council

DE developers that install after 2003 will be required to reapply for permit in 2007, meeting 2007 emissions regulations with BACT. Therefore DE developers will invest now in equipment with BACT that meets the 2007 regulations.

Load Factors

Washington Substation

Month	Prosper Load Factor	Total
Aug-03	0.6698	0.5598
Sep-03	0.6352	0.4954
Oct-03	0.6740	0.6206
Nov-03	0.5313	0.7475
Dec-03	0.7158	0.6360
Jan-04	0.7193	0.7448
Feb-04	0.7093	0.7339
Mar-04	0.5574	0.6836
Apr-04	0.6480	0.6761
Jun-04	0.6282	
Jul-04	0.6831	0.6290
	NOTE: No reliable data exists for April 19 to June 10, 2004	NOTE: No reliable data exists for April 19 to July 15, 2004

Lincoln Substation

Month	Justice Load Factor	Total
Aug-03	0.4942	0.5015
Sep-03	0.4277	0.4005
Oct-03	0.4848	0.4765
Nov-03	0.3439	0.6197
Dec-03	0.5281	0.6009
Jan-04	0.6014	0.6432
Feb-04	0.3465	0.5986
Mar-04	0.5294	0.5813
Apr-04	0.2952	0.3383
May-04	0.4935	0.3686
Jun-04	0.5675	0.6232
Jul-04	0.4788	0.4775

Appendix C - California Emissions Requirements

Distributed generation projects in California must obtain a permit from the governing local air district. If the local air district exempts the project, the project must obtain a permit directly from the California Air Resources Board (CARB). The CARB 2003 emissions standards are listed in Table 23 below. Units in operation before 2003 are not subject to these regulations.

Table 23 - 2003 Emission Standards (lb/MW-hr)

Pollutant	DG Unit not Integrated with Combined Heat and Power	DG Unit Integrated With Combined Heat and Power
Oxides of Nitrogen (NO_x)	0.5	0.7
Carbon Monoxide (CO)	6.0	6.0
Volatile Organic Compounds (VOCs)	1.0	1.0
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 standard cubic feet (scf)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 standard cubic feet (scf)

DG units installed after 2007 must meet the emissions regulations in Table 24. All DG units installed after 2003 must be recertified to meet the 2007 emissions regulations by 2007.

Table 24 - 2007 Emission Standards (lb/MW-hr)

Pollutant	Emission Standard
Oxides of Nitrogen (NO_x)	0.07
Carbon Monoxide (CO)	0.10
Volatile Organic Compounds (VOCs)	0.02
Particulate Matter (PM)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain per 100 scf

Air Pollution Control District (Prosper Circuit)

All new stationary sources that may emit one or more affected pollutants must meet the requirements of Rule 2201 of the New Source Review. The requirements applicable to this project are summarized below:

Emission offset requirements[2] are triggered, on a pollutant-by-pollutant basis, if the source emits more than the following pollutant amounts:

NOx: 20,000 lbs/yr
SOx: 5,750 lbs/yr
CO: 200,000 lbs/yr
PM10: 29,200 lbs/yr
VOC: 20,000 lbs/yr

BACT[3] requirements are triggered, on a pollutant-by-pollutant basis, if the source emits more than 2 lbs/day of any of the above listed pollutants.

District permit exemptions that may apply to this project include IC engines less than 50 braking horsepower, and gas turbines with a maximum heat input of 3,000,000 Btu/hr (roughly 250 kW @ 28% electrical efficiency) or less at ISO Standard Conditions.

BACT requirements depend on the emission source.

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[2] Purchase of emissions reduction credits that offset the entire stationary source's potential to emit in excess of the offset trigger level.

[3] Best Available Control Practice (BACT): is the most stringent emission limitation or control technique of the following:

- Achieved in practice for such category and class of source
- Contained in any State Implementation Plan approved by the EPA for such category and class of source
- Contained in an applicable federal New Source Performance Standard
- Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the Association of Public-Safety Communications Officials, International to be cost effective and technologically feasible for such class or category of sources or for a specific source.

Air Quality Management District (Justice Circuit)

All new stationary sources that may emit one or more of the affected pollutants must meet the requirements of Rules 1303 and 1304. The requirements applicable to this project are summarized below:

Emission offset requirements are triggered, on a pollutant-by-pollutant basis, if the source emits more than the following pollutant amounts:

NOx: 4 tons/yr
SOx: 4 tons/yr
CO: 29 tons/yr
PM10: 4 tons/yr
VOC: 4 tons/yr

BACT is triggered, on a pollutant-by-pollutant basis, if the source emits more than 1 lb/day of any of the above listed pollutants.

District permit exemptions that may be applicable to this project, include:

1. IC engines less than 50 braking horsepower
2. Gas turbines with a heat input of no more than 2,975,000 Btu/hr (roughly 250 kW @ 28% electrical efficiency) or less at ISO Standard Day Conditions
3. Fuel cells that use phosphoric acid, molten carbonate, proton exchange, membrane or solid oxide technologies
4. Internal combustion engines used exclusively for training at educational institutions
5. Portable internal combustion engines, registered pursuant to the California Statewide Portable Engine Registration Program

BACT requirements depend on the source emitter.

Appendix D - Storage Device Definitions

Suggested Storage Device Definitions for DOE study
Exploring Distributed Energy Alternatives to Electrical Distribution Grid Expansion

Note: Much of the storage capital costs are proportional to storage discharge duration, which, itself, is highly dependent on the exact application of the storage device. An assumption of five-hour dispatch duration was made for the purpose of this estimate. Applications requiring less than five hours will have appreciably lower capital costs.

Near-Term Storage Technology
Lead acid battery system, potentially relocatable
Assuming five hour storage discharge duration design
1200$/kW installed cost
Fixed O&M 15$/kW-yr (assumes six-year life)
1 cent per kWh variable costs
Plus charging electricity costs
Minus discharging electricity value
75% round-trip efficiency AC to AC
For a 12-year life, add an additional $600/kW to the initial capital cost

2010 Storage Technology
Unspecified advanced battery system (e.g., sodium sulfur, ZnBr, vanadium or flow chemistry), relocatable
Assumed five-hour storage discharge duration design
1000$/kW installed cost
Fixed O&M cost, 20$/kW-yr (assumes twelve year life)
1 cent per kWh variable costs
Plus charging electricity costs
Minus discharging electricity value
75% round-trip efficiency AC to AC

References:

1. Shoenung, Dr. Susan M., Hassenzahl, William M. *Long- versus Short-Term Energy Storage Technologies Analysis A Life-Cycle Cost Study*, SAND2003-2783, August 2003.

2. James Eyer and Joe Iannucci, Distributed Utility Associates, prepared for NRECA Cooperative Research Network: *Bulk Energy Storage for Cooperatives*, CRN Project 02-20, 2003.

Appendix E – Utility Economics Calculations

Utility installs a new 13 MW circuit at a given cost and no customers install advanced energy technologies.

10-Yr NPV	Utility Installs 13 MW Circuit in Year 0	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Utility (million kWh)	58.3	59.1	59.8	60.6	61.4	62.2	63.0	63.8	64.7	65.5	66.4
-	Peak Load (kW) Before New Circuit	12,463	12,625	12,789	12,955	13,124	13,294	13,467	13,642	13,820	13,999	14,181
-	Revenue Growth @ 1.3% Load Growth	$0	$117,524	$119,052	$120,599	$122,167	$123,755	$125,364	$126,994	$128,645	$130,317	$132,011
-$44,683	$746K Circuit Paid for in Year 0	-$746,000	$117,524	$119,052	$120,599	$122,167	$123,755	$125,364	$126,994	$128,645	$130,317	$132,011
-$1,164,325	$2M Circuit Paid for in Year 0	-$2,000,000	$117,524	$119,052	$120,599	$122,167	$123,755	$125,364	$126,994	$128,645	$130,317	$132,011
-$3,842,897	$5M Circuit Paid for in Year 0	-$5,000,000	$117,524	$119,052	$120,599	$122,167	$123,755	$125,364	$126,994	$128,645	$130,317	$132,011

Utility upgrades the 13 MW circuit to 19 MW and no customers install advanced energy technologies.

10-Yr NPV	Utility Installs 6 MW Upgrade in Year 0	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Utility (million kWh)	58.3	59.1	59.8	60.6	61.4	62.2	63.0	63.8	64.7	65.5	66.4
-	Peak Load (kW) Before New Circuit	13,000	13,169	13,340	13,514	13,689	13,867	14,048	14,230	14,415	14,603	14,792
-	Revenue Growth @ 1.3% Load Growth	$0	$118,994	$120,541	$122,108	$123,695	$125,304	$126,932	$128,583	$130,254	$131,947	$133,663
$93,448	$600K Upgrade Paid for in Year 0	-$600,000	$118,994	$120,541	$122,108	$123,695	$125,304	$126,932	$128,583	$130,254	$131,947	$133,663

Utility promotes a degree of load reduction through customer-owned technology and does not upgrade the circuit.

10-Yr NPV	Customers Install 4.2 MW of CHP over 3 yrs	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Customer (million kWh)	0.0	8.9	10.6	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
-	Energy Supplied by Utility (million kWh)	58.3	50.2	49.3	48.5	49.3	50.1	50.9	51.7	52.5	53.3	54.2
-	Load Reduction (kW)	0	-3,000	-3,300	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500
-	Peak Load after Load Reduction (kW)	12,463	9,625	9,489	9,455	9,624	9,794	9,967	10,142	10,320	10,499	10,681
-$4,186,040	Revenue Loss due to Customer CHP	$0	-$1,525,728	-$795,166	-$827,468	-$650,402	-$649,275	-$648,133	-$646,977	-$645,805	-$644,618	-$643,416

10-Yr NPV	Customers Install 2 MW of CHP over 7 yrs	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Customer (million kWh)	0.0	1.5	2.9	4.4	5.9	5.9	5.9	5.9	5.9	5.9	5.9
-	Energy Supplied by Utility (million kWh)	58.3	57.6	58.4	57.7	58.5	57.8	58.6	58.0	58.8	59.7	60.5
-	Load Reduction (kW)	0	500	500	850	850	1,275	1,275	1,700	1,700	1,700	1,700
-	Peak Load (kW)	12,463	12,125	12,289	12,105	12,274	12,019	12,192	11,942	12,120	12,299	12,481
-$1,059,957	Revenue Loss due to Customer CHP	$0	-$182,915	-$20,813	-$254,443	-$92,312	-$341,708	-$179,548	-$428,915	-$266,725	-$265,538	-$264,336

Utility installs a new circuit assuming that no customer-owned technologies will be installed, but customers do install technologies for economic reasons.

10-Yr NPV	Utility Installs 13 MW Circuit in Year 0 for $2M and Customers Install 4.2 MW of CHP over 3 yrs	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Customer (million kWh)	0.0	8.9	10.6	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
-	Energy Supplied by Utility (million kWh)	58.3	50.2	49.3	48.5	49.3	50.1	50.9	51.7	52.5	53.3	54.2
-	Load Reduction (kW)	0	-3,000	-3,300	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500	-3,500
-	Peak Load after Load Reduction (kW)	12,463	9,625	9,489	9,455	9,624	9,794	9,967	10,142	10,320	10,499	10,681
-	Revenue Loss due to Customer CHP	$0	-$1,525,728	-$795,166	-$827,468	-$650,402	-$649,275	-$648,133	-$646,977	-$645,805	-$644,618	-$643,416
-$5,971,755	$2M Circuit Paid for in Year 0	-$2,000,000	-$1,525,728	-$795,166	-$827,468	-$650,402	-$649,275	-$648,133	-$646,977	-$645,805	-$644,618	-$643,416

10-Yr NPV	Utility Installs 13 MW Circuit in Year 0 for $2M and Customers Install Economically Feasible CHP, EE, and PV over 10 years	0	1	2	3	4	5	6	7	8	9	10
-	Energy Supplied by Customer (million kWh)	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0
-	Energy Supplied by Utility (million kWh)	58.3	56.3	54.3	52.3	50.3	48.3	46.3	44.3	42.3	40.3	38.3
-	Load Reduction (kW)	0	-430	-860	-1,290	-1,720	-2,150	-2,580	-3,010	-3,440	-3,870	-4,300
-	Peak Load after Load Reduction (kW)	12,463	12,195	11,929	11,665	11,404	11,144	10,887	10,632	10,380	10,129	9,881
-	Revenue Loss due to Customer CHP	$0	-$310,558	-$401,116	-$491,674	-$582,232	-$672,790	-$763,348	-$853,906	-$944,464	-$1,035,022	-$1,125,580
-$4,990,082	$2M Circuit Paid for in Year 0	-$2,000,000	-$310,558	-$401,116	-$491,674	-$582,232	-$672,790	-$763,348	-$853,906	-$944,464	-$1,035,022	-$1,125,580

Appendix F – Example Rule 21 Conceptual Review Application

Identifying the DG system's Location and Responsible Parties

A. Host Customer Facility Information (Where will the DG system be installed?)

Name shown on SCE service account	Electric Service Account Number	Meter Number

NOTE: If available, please also submit a copy of the host Customer facility's utility bill.

Street Address	City	State	Zip

B. Contact Information (Who should be contacted for additional information, if necessary?)

Contact Person	Company Name

Phone	Fax	Email

Mailing Address	City	State	Zip

Backup Contact Person (Optional)	Company Name

Phone	Fax	Email

Mailing Address	City	State	Zip

C. Operating Date (What date is this DG system expected to begin operation?)

Describing the DG system and Host Customer's Electrical Facilities

A (MP&I)	Indicate how this DG system will interface with SCE's Distribution System.	1 2 3 (Choose one)

Instructions and Notes

Choose from the following three interface options:

1. **Parallel Operation:** The DG system will interconnect and operate "in parallel" with SCE's Distribution System for more than one (1) second.
2. **Momentary Parallel Operation:** The DG system will interconnect and operate on a "momentary parallel" basis with SCE's Distribution System for a duration of one (1) second or less through switches or circuit breakers specifically designed and engineered for such operation.
3. **Isolated Operation:** The DG system will be "isolated" and prevented from becoming interconnected with SCE's Distribution System through a transfer switch or operating scheme specifically designed and engineered for such operation.

If the answer is option 1, "parallel operation," please supply all of the information requested for the DG system.

If the answer is option 2, "momentary parallel operation," only questions A, E and F of this Part 3 and questions A, B, E, F, I, L, M, N, and S of Part 4 need be answered.

If the answer is option 3, "Isolated Operation," only questions A, E, and F of this Part 3 and questions A, B, F, and S of Part 4 need be answered.

B	If the Answer to Question A was option 1, please indicate the type of agreement that is being requested with this Application. If options 2 or 3 were selected, please skip to questions E and F. If options 2, 3, or 4 to this question B are chosen, please provide an estimate of the monthly kWh the DG system is expected to deliver to SCE's Distribution System. If SCE determines that the amount of power to be exported is significant in relation to the capacity available on its Distribution System, it may request additional information, including time of delivery or seasonal kWh estimates.	1 2 3 4 (Choose one) _______________ KWh

Instructions and Notes

Sample agreements are available from SCE for review. Choose from the following four Agreement options:

1. **A DG system Interconnection Agreement** that provides for parallel or momentary parallel operation of the DG system, but does not provide for exporting power to SCE's Distribution System.
2. **A DG system Interconnection Agreement** that provides for parallel operation of the DG system, and the occasional, inadvertent, non-compensated, export of power to SCE's Distribution System. (This type of Agreement has not yet been developed by SCE or approved by the CPUC. Check with SCE for availability.)
3. **A "Qualifying Facility" Power Purchase Agreement** that provides for parallel operation of the DG system, and exporting power to SCE's Distribution System for sale to SCE. This option is available only to "Qualifying Facilities" with a total Nameplate Capacity of 100 kW or less. See Question F for the definition of a Qualifying Facility.
4. **A Net Energy Metering Agreement** that provides for parallel operation of the DG system, and exporting power to SCE's Distribution System for credit under the terms of SCE's Net Energy Metering Tariff. This option is available only to solar and wind powered DG systems per the terms of Section 2827 of the California Public Utilities Code.

D	What is the maximum 3-phase fault current that will be contributed by the DG system to a 3-phase fault at the Point of Common Coupling (PCC)? (If the DG system is single phase in design, please provide the contribution for a line-to-line fault.) Please indicate the short circuit interrupting rating of the host Customer facility's service entrance ("main") panel:	_______________ Amps _______________ Amps

Instructions and Notes

Refer to SCE's Rule 21, Section D. 3. a. (2) and Section I.3.g. for significance and additional information. To determine this value, any transformers and/or significant lengths of interconnecting conductor used between the each of the Generators (if there are more than one) that make up the DG system and the PCC must be taken into account. The details, impedance, and arrangement of such transformers and cable runs should be shown on the single-line diagram that is provided. Consult an electrical engineer or the equipment supplier if assistance is needed in answering this question.

It is expected that most Applicants will want to reserve the flexibility to operate any or all of their Generators in parallel. However, if the design of the proposed installation will limit the amount of generation capacity that may be interconnected at any time to SCE's Distribution System, please describe the assumptions used in calculating the maximum fault current contribution value.

E (MP&I)	Please indicate how this DG system will be operated.	1 2 3 4 5 (Please choose all options that may apply.)

Instructions and Notes

Choose from the following five operation options:

1. **Combined Heat and Power or Cogeneration** – Where the operation of the DG system will produce thermal energy for a process other than generating electricity.
2. **Peak Shaving/Demand Management** – Where the DG system will be operated primarily to reduce electrical demands of the host Customer facility during SCE's "peak pricing periods."
3. **Primary Power Source** – Where the DG system will be used as the primary source of electric power and that power supplied by SCE to the host Customer's loads will be required for supplemental, standby or backup power purposes only.
4. **Standby / Emergency / Backup** – Where the DG system will normally be operated only when SCE's electric service is not available.
5. **Net Energy Metering** – Where the DG system qualifies and receives service under SCE's Net Energy Metering tariff.

F (MP&I)	Please indicate if Qualifying Facility Status will be obtained from the Federal Energy Regulatory Commission (FERC) for this DG system.	Yes No

Instructions and Notes

Parties operating DG systems complying with all of the requirements for qualification as either a small power production facility or cogeneration facility pursuant to the regulations of the Federal Energy Regulatory Commission (18 Code of Federal Regulations Part 292, Section 292.203 et seq.) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. Section 796, et seq.), or any successor requirements for "Qualifying Facilities" may seek certification from FERC to have the DG system designated as a Qualifying Facility or "QF." In summary, Qualifying Facilities are DG systems using renewable or alternative fuels as a primary energy source or facilities that utilize the thermal energy given off by the generation process for some other useful purpose. QF facilities enjoy certain rights and privileges not available to non-QF DG systems.

QF status is <u>not</u> required to interconnect and operate in parallel with SCE's Distribution System.

Appendix G – BEA Calibration Procedures

Retrofit Wizard - Calibrating the Simulation

Calibration Principles

The goal of any retrofit study is to establish a baseline model, which adequately reflects characteristics of the existing building so that the energy cost savings estimate for alternative equipment is reasonable. For example, if a building with electric cooling and gas heating has an incremental summer electric demand of 500 kW, then any change in cooling equipment cannot produce more than 500 kW savings in electric demand. However, the incremental demand may vary from year to year depending on the severity of the summer peak day. Weather-normalized calibration comparisons offer the best method to assess the ability of the baseline simulation model to reasonably predict the energy cost impact of alternative equipment configurations.

Calibrations may be assessed using annual, monthly, or hourly data and may compare whole building energy use or a variety of other more specific data such as equipment loads or energy consumption broken down by end-use. In this program, the whole monthly building energy use is the basis for calibration comparisons, because this type of data is generally available from utility bills. Two key factors must be adjusted when making this comparison: length of a billing period and variations in weather. The weather for both the existing application and the simulation is characterized by four monthly values:

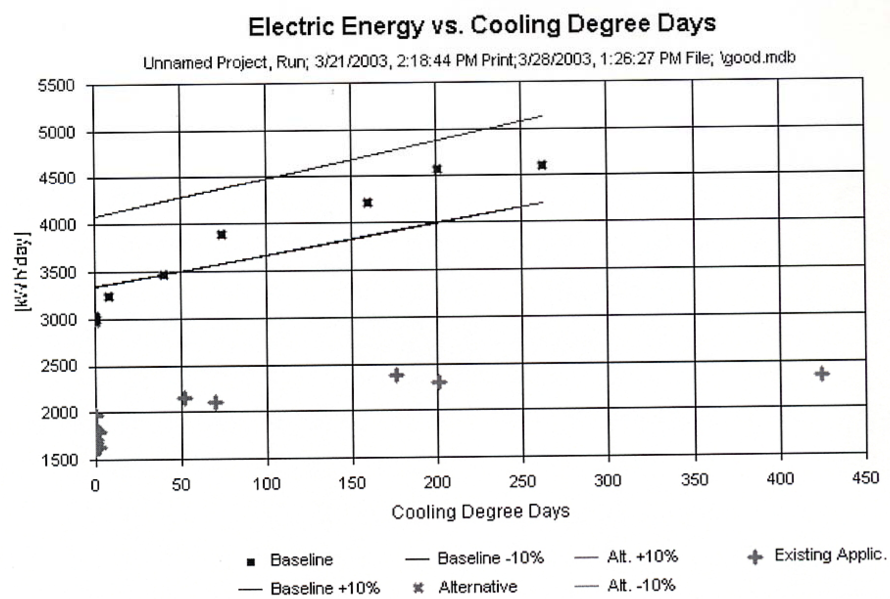
- Cooling degree days (average per day for the month) which directly impacts cooling energy consumption.
- Heating degree days (average per day for the month) which directly impacts heating energy consumption.
- Maximum dry bulb temperature which directly impacts cooling energy peak demand.
- Minimum dry bulb temperature which directly impacts heating energy peak demand.

There is a variety of ways in which the simulation and/or the existing application data can be normalized to provide a comparison on a consistent basis. The method chosen for this program is to graphically present the data in normalized scatter plots, which are discussed below.

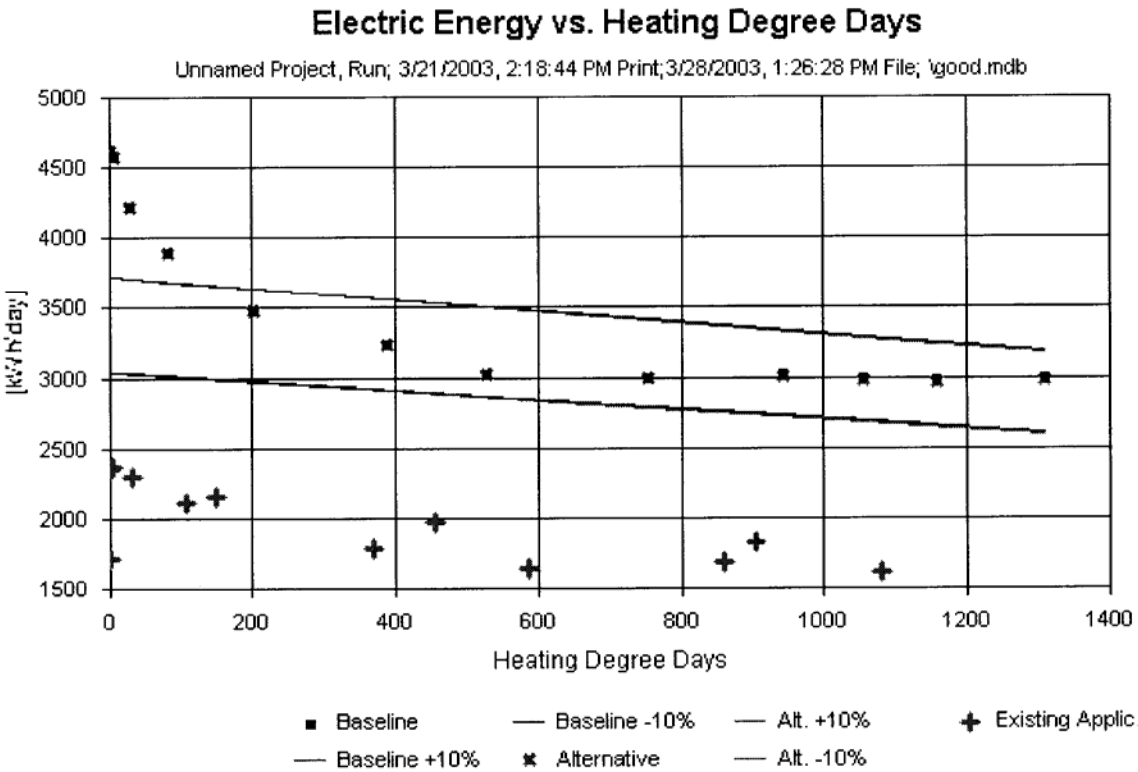
Calibration Charts

The retrofit calibration charts provide a way to evaluate the simulation energy use and demand characteristics against the existing application utility bill data. Each type of chart is useful for calibrating different characteristics of the simulation model, however these characteristics are not completely independent of each other:

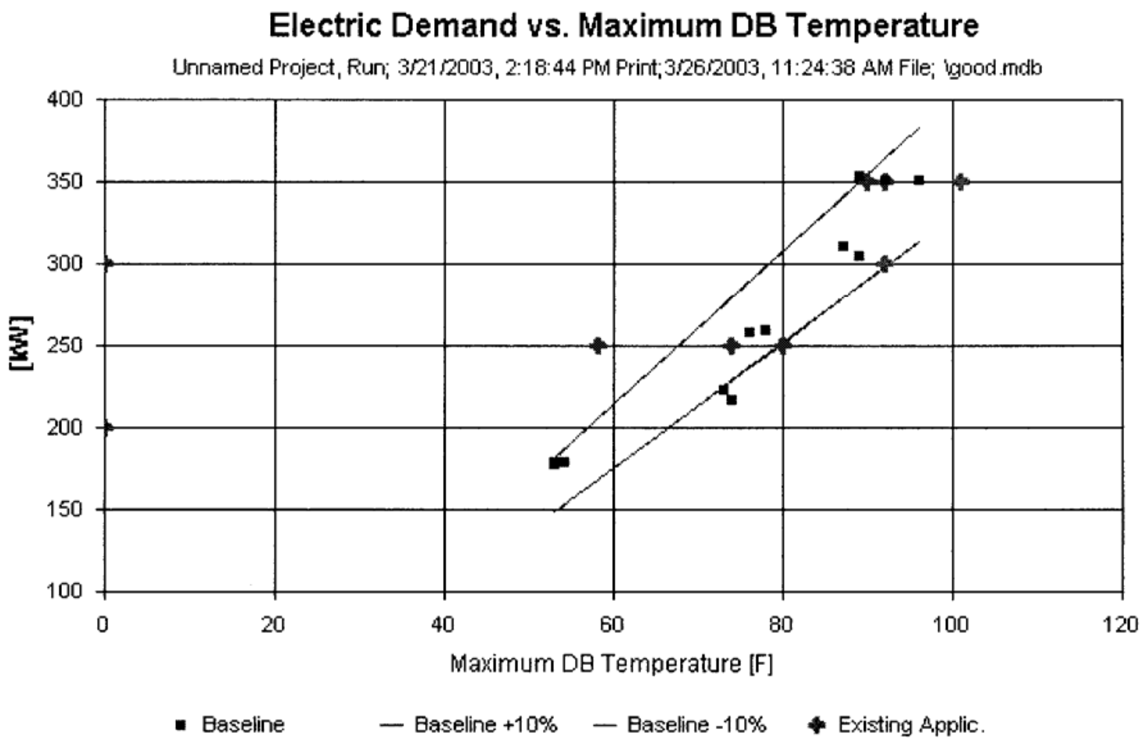
- Electric Energy vs. Cooling Degree Days [kWh/day vs. Degree-days]



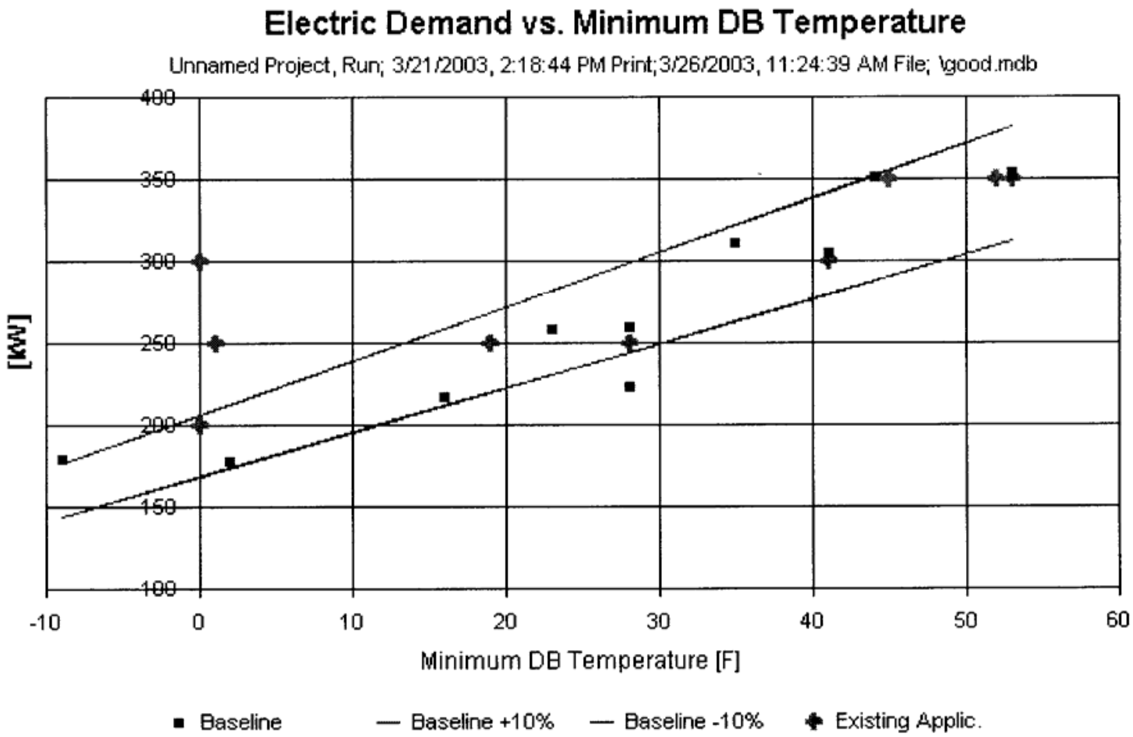
- Electric Energy vs. Heating Degree Days [kWh/day vs. Degree-days]



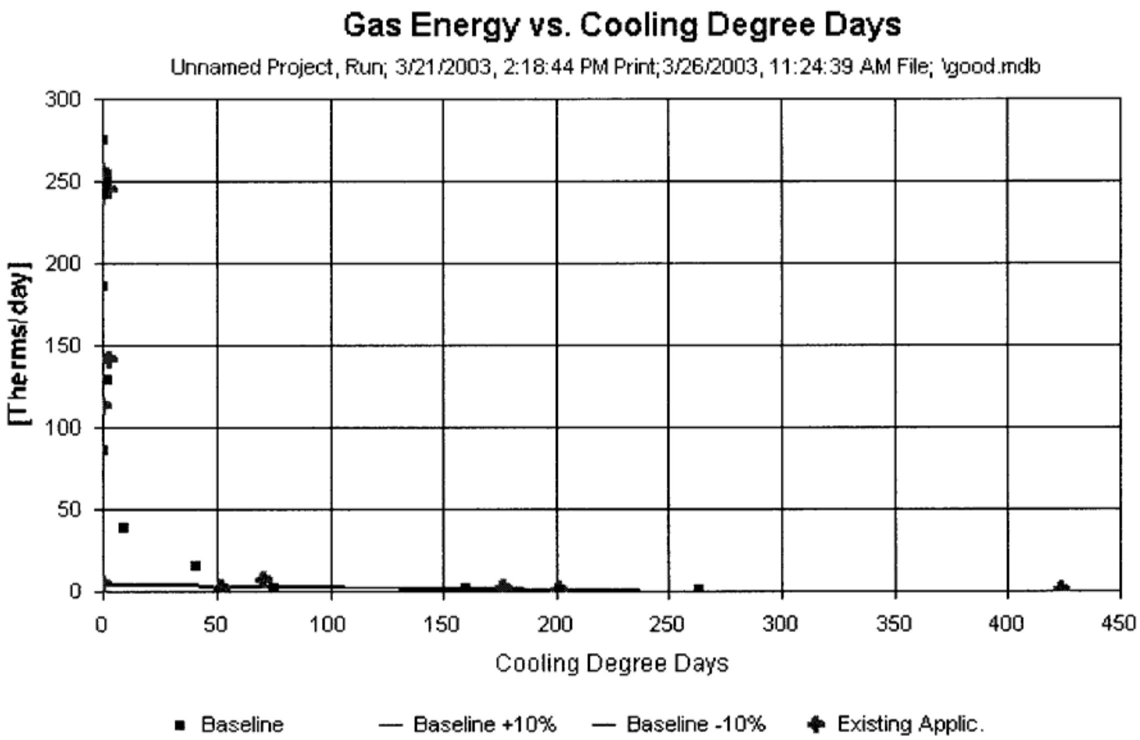
- Electric Demand vs. Daily Maximum Dry-Bulb Temperature [kW vs. °F]



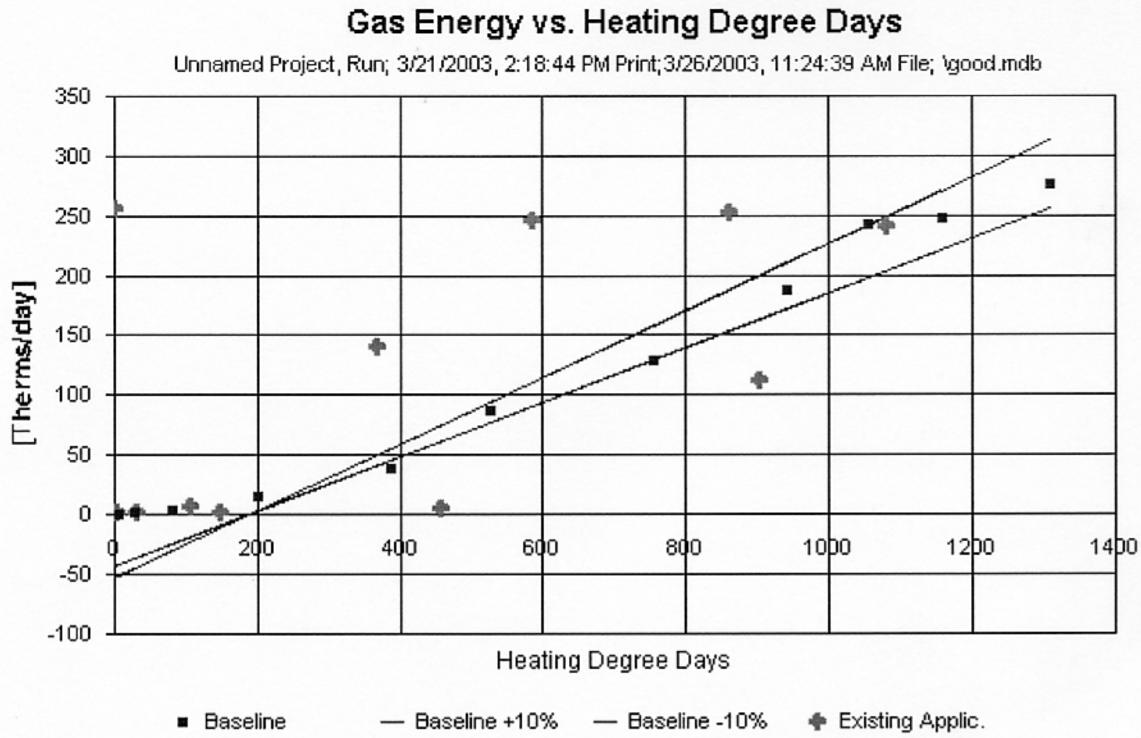
- Electric Demand vs. Daily Minimum Dry-Bulb Temperature [kW vs. °F]



- Gas Energy vs. Cooling Degree Days [therms/day vs. Degree-days]



- Gas Energy vs. Heating Degree Days [therms/day vs. Degree-days]



The table below summarizes the major relationships between drivers and the slope and intercept of the six calibration charts. While there may be offsetting interactions between the various drivers, adjusting them roughly in the order listed will help to move the simulation results in line with the existing application data. The main approach is establishing the intercepts by adjusting the non-weather-dependent loads and then bringing the slopes in line by adjusting the weather-dependent loads. Calibration is an iterative process that should become easier with experience.

Driver	kWh vs. CDD		kWh vs. HDD		kW vs. Max DB		kW vs. Min DB		therms vs. CDD		therms vs. HDD	
= *Slope,* = *Intercept =>*												
Non-Weather-Dependent												
Lights and Elec. Equip. kW		◆		◆		◆		◆		◆		◆
Lights and Elec. Equip. hrs		◆		◆						◆		◆
Occupancy People		◆		◆		◆		◆		◆		◆
Occupancy Hours		◆		◆						◆		◆
Gas Equipment Load										◆		◆
Weather-Dependent												
Building Envelope	◆		◆		◆		◆		◆		◆	
Glazing Percent	◆		◆		◆		◆		◆		◆	
Ventilation-Infiltration Rate	◆		◆		◆		◆		◆		◆	
Electric Cooling Efficiency	◆				◆							
Electric Heating Efficiency			◆				◆					
Gas Cooling Effic. (COP)									◆			
Gas Cooling Parasitics	◆				◆							
Gas Heating Efficiency											◆	

Building Energy Analyzer (PRO) 2.4

Appendix H - Building Energy Analyzer Life Cycle Cost Payback Definitions

LCC Payback

Number of years needed to generate positive present value cumulative cash flow for the alternative configuration when compared with the baseline present value cumulative cash flow.

Simple Payback

Installed cost (including O&M costs) of alternative configuration divided by annual utility savings.

Cash Flow

The cash flow describes the yearly net cash flow resulting from an investment in a particular alternative. It is the sum of the operating expenses minus any tax credits or depreciation and is determined by the following equation:

$$CFE_{c,n} = (U_{c,n} + M_{c,n} + INT_{c,n} + PRC_{c,n}) - (TR * (U_{c,n} + M_{c,n} + INT_{c,n} + TD_{c,n}))$$

Where:

c = alternative (baseline, or alternative)
n = year

CFE c,n = cash flow
U c,n = utility expense
M c,n = operation and maintenance expense
INT c,n = loan interest expense
PRC c,n = loan principal expense
TR = income tax rate
TD c,n = tax depreciation

NOTE: BEA does not take into account the effects of insurance expense, property tax, equipment salvage value, or replacement expense.

Cash Flow Present Value

Present value cash flow is the process of discounting future cash flows back to present day value.

$$\text{Yearly Discount Factor} = 1/(1+k)^n$$

Where:

k = Yearly discount rate, or also called cost of capital
n = Number of years

*Present Value Cash Flow = Cash Flow Effect * Yearly Discount Factor*

Present Value Cash Flow Example (using 10% cost of capital /discount rate)

Year	Cash Flow Effect	Yearly Discount Factor	Present Value
1	$156,392	0.909090909	$142,174.55
2	$169,807	0.826446281	$140,336.36

3	$177,270	0.751314801	$133,185.57
4	$185,076	0.683013455	$126,409.40
.			
.			
20	$386,716	.0148643628	$57,482.87

Study Period

Study period is the period for which the study is to be taken.

Depreciation Period

Depreciation period represents the length of time required to fully depreciate the cost of the project.

Finance Period

The finance period is the years required to retire the debt incurred in financing the project.

% Financed

Percent financed is the amount the project that is being financed with debt.

Financing Interest Rate

Financing interest rate is the interest percentage that will be paid on the money borrowed to finance the new project.

Cost of Capital

Cost of capital represents the discount factor by which all future yearly cash flows will be discounted back to present day value.

Tax Rate

Tax Rate is the income tax rate.

Depreciation

Depreciation is calculated by the straight-line method.

SL - Straight Line

In the straight-line method, the payments are divided into equal annual charges over the life of the project. The depreciation calculation is as follows:

Depreciation Rate = Depreciable Value / Useful Life

For example:

Depreciable Value	$100,000
Estimated Useful Life	20 years

Depreciation rate = 100,000/20 = $5,000 / year

Year	Beginning Balance	Depreciation Charge	Year	Beginning Balance	Depreciation Charge
1	$100,000	$5,000	11	$50,000	$5,000
2	$95,000	$5,000	12	$45,000	$5,000

3	$90,000	$5,000	13	$40,000	$5,000
4	$85,000	$5,000	14	$35,000	$5,000
5	$80,000	$5,000	15	$30,000	$5,000
6	$75,000	$5,000	16	$25,000	$5,000
7	$70,000	$5,000	17	$20,000	$5,000
8	$65,000	$5,000	18	$15,000	$5,000
9	$60,000	$5,000	19	$10,000	$5,000
10	$55,000	$5,000	20	$5,000	$5,000
Total	$100,000				

This report was prepared under Subcontract between UT-Battelle, Prime Contract No. 4000031103 with the U.S. Department of Energy, and Gas Technology Institute

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