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Renewable Distributed Generation Assessment: Sacramento Municipal Utility District Case Study

PIER FINAL PROJECT REPORT

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Environmentally-Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Energy Systems Integration

What follows is the third of four studies completed for the Distributed Generation Assessment project, contract 500-01-042, conducted jointly by Energy and Environmental Economics, Inc., and Electrotek Concepts, Inc. The report is entitled Renewable Distributed Generation Assessment: Sacramento Muncipal Utilities District Case Study. This project contributes to the Renewable Energy Technologies program.

For more information on the PIER Program, please visit the Energy Commission's Web site http://www.energy.ca.gov/pier/reports.html or contact the Energy Commission's Publications Unit at (916)-654-4628.

ABSTRACT

This case study presents the results of the second application of a renewable distributed generation assessment methodology conducted for Sacramento Municipal Utility District (SMUD). SMUD is one of four distribution system evaluated under the RDG Assessment project conducted under the auspices of the CEC PIER Renewables program. In addition to SMUD, the three other distribution systems evaluated include Alameda Power & Telecom (Alameda P&T), the San Francisco PUC / Hetch Hetchy (SF PUC), and the City of Palo Alto Utilities (CPAU). The overall objective of this project is to accelerate the deployment of renewable energy systems in a distributed generation mode by fully accounting for all benefits.

Keywords: renewable distributed generation, assessment methodology, municipal utility planning, Sacramento Municipal Utility District, avoided costs, reliability analysis, uncertainty analysis

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EXECUTIVE SUMMARY

Introduction

In an effort to contribute to the baseline knowledge of distributed generation value, this case study reports the methodology and results of the combined economic and engineering analysis performed by Energy and Environmental Economics, Inc. (E3) and Electrotek Concepts (ETK) under a California Energy Commission (CEC) PIER program-funded contract. The aim of this research project is to develop a methodology for evaluating the potential renewable distributed generation (RDG) applications within the municipal utility planning process. The resulting methodology from this research will be integrated with nine other related research projects occurring in parallel to this RDG Assessment project to further the greater goals of the CEC PIER program. Figure 1 maps how this RDG Assessment Project relates to the other research areas under this program.

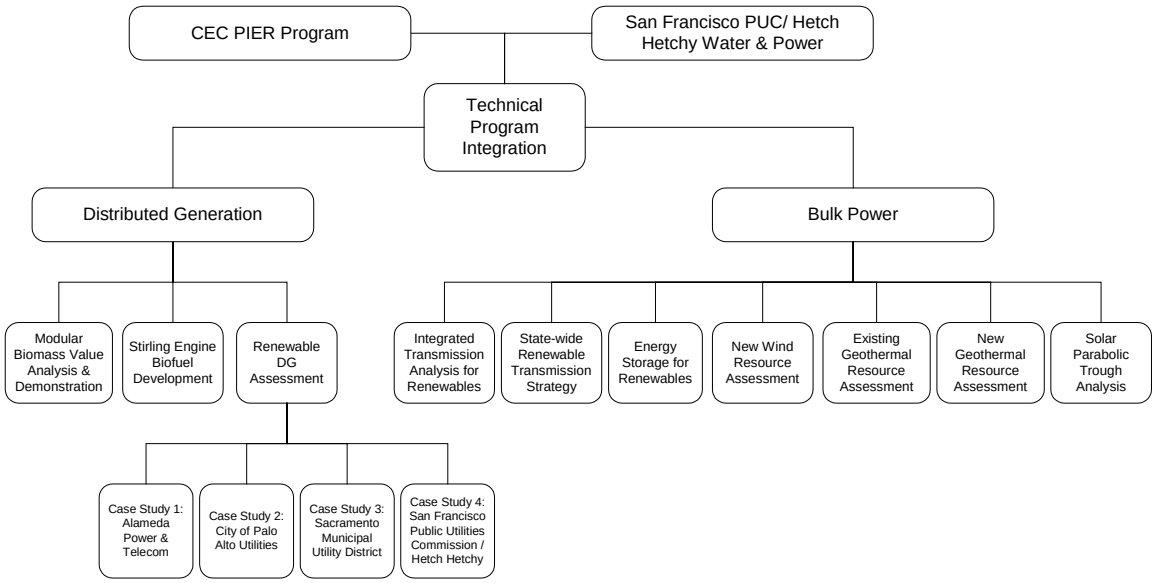

Figure 1: CEC PIER Program Research Project Structure

The following discussion comprises the results of the third of four case studies for the application of the RDG Assessment methodology. This case study describes the analytical process and associated results for the Sacramento Municipal Utility District (SMUD) distribution system. The analysis results for the remaining three municipal utilities are provided as separate cases study reports for the San Francisco Public Utilities Commission/ Hetch Hetchy (SF PUC), Alameda Power and Telecom (Alameda P&T), and the City of Palo Alto Utilities (CPAU).

Purpose

Numerous detailed screening studies for large transmission and distribution systems have identified several elements of value that distributed generation can provide. These include capital deferral, reduced losses, reduced O&M costs, and risk reduction. These elements focus on cost reduction to the wires company or an integrated utility. Although it has been postulated that distributed renewable generation can provide enhanced reliability, very little in the way of quantitative analysis has been completed to include the reliability impact in DG evaluation. This research builds upon this body of work and is focused on utility's internal planning processes.

As such, the purpose of this Renewable Distributed Generation Assessment project is to develop a sound and replicable methodology for evaluating RDG within a utility planning process. The methodology developed jointly by E3 and ETK was applied in four municipal utility case studies throughout Northern California with the goal of facilitating the installation of cost-effective RDG systems in California.

The core contributions of this research include the following:

- Analysis of the local system impacts and benefits that accrue directly to a municipal UDC in a localized network
- Expansion of the evaluation methodology to evaluate the impacts on local system reliability, including value to both the customers and the UDC
- Incorporation of uncertainty for elements of RDG project value such as local load growth, wholesale energy prices, and capital costs for equipment

Project Objective

The overall objective is to accelerate the deployment of renewable distributed generation by fully accounting for all benefits. The specific objectives of the project are to (1) identify the best locations for distributed renewable generation (DG) in a local Utility Distribution Company (UDC) system, (2) include reliability impacts in the analysis, and (3) assess the impact of load growth and generator performance uncertainty on the results.

The key measure of success of this project is establishing an understanding of the merits of distributed renewable generation in distribution systems in general, embodied in the comprehensive application to four example distribution systems. Successful completion of this research will result in reduced overall system costs, enhanced local reliability, and increased resource diversity. The key anticipated outcome is an established and verified methodology with readily accessible tools for rapid assessment of distributed renewable technologies, applicable to any distribution network.

Results

The results of the SMUD case study RDG Assessment project are two-fold. First, this project represents a successful application of the RDG Assessment methodology developed by E3 and ETK. Second, the results provide SMUD with valuable information for future decision making that includes the specific benefits RDG could provide on their distribution system.

Highlights of the assessment results provided in this report include these findings:

- *It is difficult to find cost-effective RDG.* Certain opportunities do exist, but they require an array of favorable circumstances to generate net benefits.
- *Two of the three cost-effective technologies identified were combined heat & power (CHP).* The ability to capture and use waste heat creates an additional income stream for RDG projects that can tip the balance towards cost-effectiveness. CHP is only an option with combustion-based RDG technologies.
- *The modeling of a 1.5 MW wind turbine resulted in the third cost-effective technology.* Even though a wind turbine of this size is technically not distributed, if an adequate wind resource exists in SMUD territory, this could result in a cost-effective renewable project.
- *RDG's ability to defer distribution projects can provide economic benefits.* However, the overall effect of the distribution deferral benefits is expected to be modest.

Engineering Screening

- No likely operational problems (e.g. voltage/overcurrent) were indicated for the three RDG cases that we evaluated. Among these, we note the following:
- 13.5 MW of RDG sited for loss reduction resulted in a net peak incremental loss reduction of 5%.
- 20 MW of dispersed solar PV resulted in only 2% peak loss reduction.
- 13.5 MW DG sited for released capacity is likely best for reliability improvement from feeder capacity.

Reliability Screening

- Solar PV can achieve a high (45%) incremental capacity value due to high coincidence with SMUD's summer peak.
- Well-sited RDG yields a 3-4% reliability 'bonus' when operating at peak load due to reducing losses as well as supplying load.
- Well-sited dispatchable RDG can yield incremental capacity increases of two to three times the generation output.

Conclusion and Recommendations

Upon initiation of this research project, the specific goals in the five-year, ten-year, and fifteen-year timeframe were identified. These included development of a robust methodology to evaluate local area resources and moving this type of analysis towards standard industry practice. The completion of the SMUD RDG Assessment represents the first step in achieving these goals.

Recommendations including the implications of the use of this methodology in California and proposed next steps are described in the Final Report for the Renewable Distributed Generation Assessment project which captures the results from all four applications of this newly developed evaluation methodology.

SACRAMENTO MUNCIPAL UTILITIES DISTRICT CASE STUDY

1.0 Introduction

This California Energy Commission (CEC) PIER-funded Renewable Distributed Generation (RDG) Assessment project provides a sound methodology for utility distribution companies (UDCs) to evaluate a wide variety of RDG options for their future resource planning needs. Given that many of the considerations for evaluating electricity resources (e.g. market prices, fuel prices, technology costs, etc.) continually change, we designed this methodology to be flexible and easily updated, so as to address the very dynamic nature of the electricity industry.

This report provides the results from our application of this RDG assessment evaluation methodology for the Sacramento Municipal Utility District (SMUD), one of the four California municipal utilities that participated in this project. Each municipal utility had its own interests and goals for participation in this project. While the methodology is the same for each, the focus of our analysis and the subsequent results are tailored to meet the needs of each utility. In addition to developing a methodology and transferring the process to the municipal utilities, our team offered the utilities an understanding of the analysis process through a three-day RDG seminar and/or other meetings, thus enabling them to continue using this evaluation methodology internally in the future.

The RDG evaluation methodology involves two analytical processes that occur simultaneously: an economic analysis and an engineering analysis. Throughout this report, we describe the methodology and results from both the economic and engineering analyses for the SMUD RDG assessment. The SMUD RDG assessment, along with that of the other three participating municipal utilities, illustrates how RDG evaluation can be integrated into the utility planning process. The RDG assessment methodology provided herein can also be used in conjunction with other ongoing CEC PIER programs to develop a systematic approach to evaluate RDG that is applicable state-wide.

1.1. Background

In January 2003, Energy and Environmental Economics, Inc. (E3) and Electrotek Concepts (ETK) began work under a CEC PIER program-funded contract to develop a methodology for evaluating RDG for municipal utilities. The following discussion of the analytical process and associated deliverables applies to each of the four participating municipal utilities, which are the San Francisco Public Utilities Commission/ Hetch Hetchy (SF PUC), Alameda Power and Telecom (Alameda P&T), City of Palo Alto Utilities (CPAU), and Sacramento Municipal Utility District (SMUD).

1.2. Overview of CEC PIER Deliverables

This project was designed to identify the best RDG projects from both economic and engineering perspectives. This includes (1) identifying the best locations for RDG in a local UDC system, (2) identifying reliability impacts in the analysis, and (3) assessing the impact of critical uncertainties on the results to provide robust conclusions. Application of this research may result in reduced overall system costs, enhanced local reliability, and increased resource diversity through the installation of cost-effective RDG technologies.

The RDG assessment for each utility is developed in several chapters, each corresponding to a major step in the evaluation as well as a deliverable in the original scope of work for this project. Taken together, these chapters constitute our team's suggested methodology for RDG planning and evaluation as applied in four specific cases.

1. **Three-day Planning Seminar on RDG Evaluation**

   This three-day seminar summarizes the methodology we have developed for this project. The course begins with traditional distribution planning and instructs how RDG evaluation can be included into this existing process. The goal of the seminar is to educate the utility engineers and resource staff in how to identify the areas of highest value for DG and where it is practical from an economic and engineering perspective.

2. **RDG Economic Screening Analysis** consists of the following three steps:

   Step 1: Define the baseline avoided costs.

   Step 2: Evaluate the cost-effectiveness of RDG from multiple perspectives.

   Step 3: Refine the potential of the RDG technologies that best suit the area needs with feedback from the engineering analysis.

   The results from the analysis performed by E3 during each of these steps will be provided in a separate chapter of this report. Specifically, the chapter will consist of the following:

   a. **Avoided Cost Memo.** This deliverable describes costs for the distribution system. The costing methodology follows the 'best practices' approach described by K. Knapp, et.al., during the NARUC conference in November 2000, and used in the CPUC draft report (currently awaiting comments) entitled "A Forecast of Cost Effectiveness Avoided Costs and Externality Adders" (January 8, 2004).

   b. **Economic Screening Analysis.** The economic screening analysis combines the area- and time-specific (ATS) distribution avoided costs with the ATS performance characteristics of RDG. Evaluation includes wind, solar PV, solar concentrator, and biomass fuels to more accurately estimate the economic potential for these technologies. In order to achieve the objective of developing a RDG evaluation methodology with readily accessible tools, we have simplified the inputs whenever possible for ease of use, while retaining the overall integrity of the results.

   c. **Load and Resource Analysis**. The load and resource analysis chapter refines the economic screening analysis with results from the engineering study and specific utility needs. The results include average marginal capacity costs, marginal operating costs, peak capacity allocation factors, and minimum size of distributed generation units needed to meet system demand requirements.

3. **RDG Engineering Screening Analysis**

a. **Engineering Circuit Model.** Using utility-specific data on system configuration and loading, ETK developed a circuit model of each UDC distribution system. This circuit model allows for the future analysis of the engineering impacts of RDG on the specific utility system.

b. **Engineering Screening Analysis.** The engineering analysis utilizes the ETK circuit model to determine the timing, magnitude and location of constraints in the electric distribution system. The ETK model analyzes the entire year, in 8,760 hourly increments, rather than a single peak load relying upon snapshots in time to evaluate how RDG output patterns interact with the distribution system. The analysis highlights the locations that need reinforcement and would benefit most from the siting of RDG, given expected performance characteristics and available resources.

4. **Reliability Analysis.** The reliability analysis chapter addresses the impact of RDG on utility reliability using three complementary methods. These methods are designed to evaluate the impacts of RDG on electric reliability.

   Method 1: Identify the number of years (or amount of MW peak growth) of improved reliability from RDG installation.

   Method 2: Estimate the reduction in expected unserved energy (EUE) on the system resulting from RDG installation.

   Method 3: Determine the reliability improvement for customers based on an estimated Value of Service (VOS).

5. **Uncertainty Analysis.** The uncertainty analysis examines how sensitive the results and recommendations for cost effective and appropriately-sited RDG are to varying conditions. This analysis incorporates 'high' and 'low' range estimates of input values, including market price, transmission costs, distribution costs, RDG capital costs, capacity factor, and fuel costs.

1.3. Analysis Process and Interrelationship of Deliverables

The first deliverable, the three-day planning seminar, is a stand-alone product that can be used either as an introduction to the methodology concepts or as a primer once the RDG evaluation is underway or completed. The seminar is organized to bring different departments of the UDC together including the distribution engineers, resource planning and management. Each group represents an important component of the overall RDG evaluation team.

The other deliverables are interrelated as represented in Figure 2. The shaded areas represent the major analyses and the boxes in each area represent the deliverables (memos) resulting from that analysis.

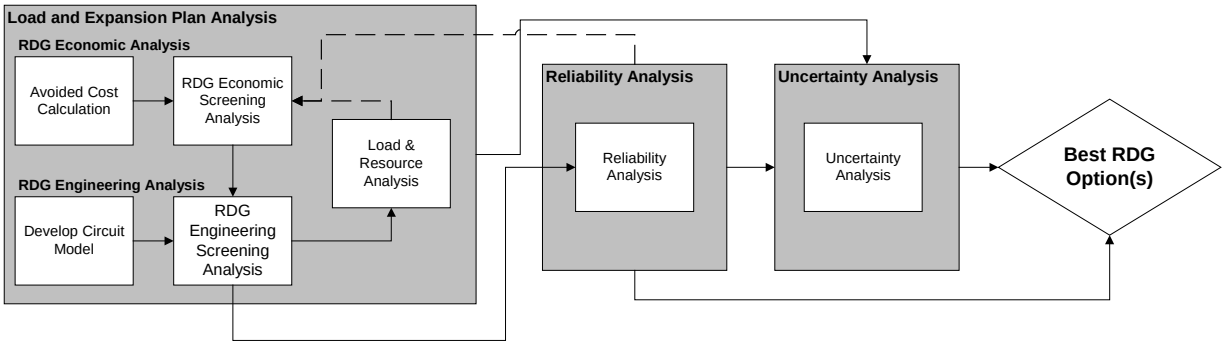

Figure 2: RDG Analysis Process Diagram

The dotted-line in the flowchart indicates the potential feedback loop between the reliability analysis and the economic screening analysis. In the normal progression of work, the economic screen would determine if there are areas with sufficiently high avoided costs to justify RDG. Then the engineering screening analysis would be conducted to fine tune the amount, location, and timing of RDG installations that would be needed to defer or replace any planned generation, distribution, or transmission upgrades. The engineering investigation continues through the reliability analysis to determine how the selected RDG would affect service reliability. The engineering screening and reliability analyses results are fed back into the economic screening to further refine the analysis.

Similarly, the overall analysis is expanded by including uncertainty evaluation. The uncertainty analysis involves the perturbation of inputs to test the sensitivity of the results to a change in key inputs. Specific inputs that may be varied include electricity price forecast, RDG costs, distribution capacity value, and RDG fuel costs. The results from this uncertainty analysis allow for a more accurate recommendation of the 'best RDG option.'

1.4. Deliverable Conveyance

As part of this analysis, our team will provide the following deliverables for each UDC.

1. **Three-day Seminar Materials**
   This deliverable will contain hard-copies of the presentation materials including slides, break-out sessions, and any other UDC-specific seminar materials.

2. **RDG Assessment Methodology and Results**
   This deliverable will be a report containing several chapters describing our methodology and results and a final RDG Assessment Report. Each chapter represents one portion of the analysis described above. The final report will be a summary of the entire RDG Assessment Project.

3. **Economic Analysis Tool**
   This deliverable will be an MS Excel spreadsheet model. This model was specifically developed for the RDG Assessment Project and contains all of the economic inputs and calculations described in the RDG Assessment Report.

1.5. Summary of Results for SMUD

SMUD's Board of Directors latest strategic direction outlined four key values to guide resource planning. These values are stated as follows[1]:

a) Emphasize local and regional environmental benefits over global benefits

b) Lower the cost to serve our customers by reducing per customer peak usage

c) Set a goal of meeting 10% of the District's load with renewables by 2006 and 20% by 2011, and thus meet or exceed the statewide RPS standard

d) Develop and deploy cost effective, clean distributed generation. As part of this policy, the District shall continue to be a leader in solar power.

This RDG analysis conducted for SMUD is aligned with the key values identified for resource planning. The results of our analysis are described in detail in each chapter of the RDG Assessment Report described above. Highlights are provided below.

1.5.1. Engineering Screening Analysis

The engineering screening analysis evaluates the feasibility of accommodating distributed generation and the potential value of that generation to the benefit of the power delivery system.

Figure 3 shows a typical diagram for the peak load case for SMUD.

[1] SMUD Board Policy, Resource Planning, Strategic Direction, Policy Number SD-9, Resolution Number 04-05-11/12, Adoption/Revision Date, May 6, 2004.

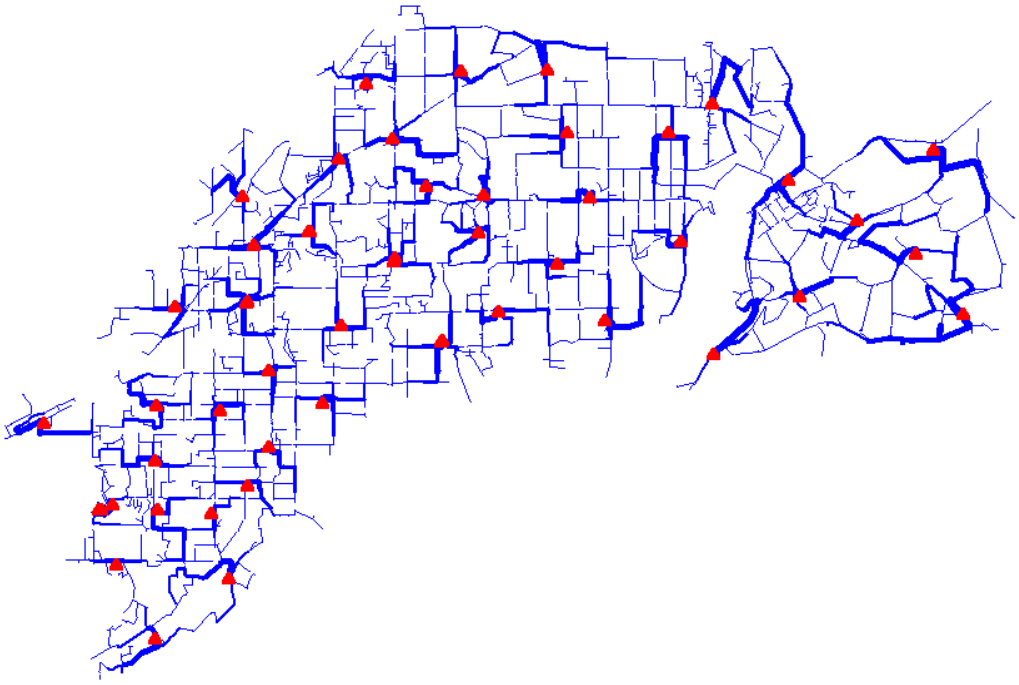

Figure 3: Power flow in the SMUD System.

The thickness of the lines in this diagram is proportional to the power flowing in the lines; therefore the main feeders are clearly visible. Each of the substations is indicated by a red triangle.

Benefits from RDG to a distribution system are very site specific and thus can have different value depending upon where it is located. The 'optimal' location for RDG will depend on what is being optimized and is quite sensitive to the size of generation. This engineering screening approach investigates both small and large unit sizes. The locations identified for small sizes are possible candidates for encouraging solar PV and small combined heat and power (CHP) applications. The locations identified for larger sizes would be possible candidates for peaking units and large CHP applications.

In this study, a 100-kW test generator was used for the small unit size, a 1,000-kW (1 MW) generator as a medium size and 5,000-kW (5 MW) for the large size. The 100-kW unit is small relative to the capacity of any of the feeders and lateral branches and should be applicable to any small generator. The 1 MW unit is typically about 15% of a given feeder's capacity and is a common size for installed DG. The 5 MW unit represents more than 50% of a given feeder's capacity and was chosen as the largest practical size, given system characteristics, that could not require significant changes to the existing system.

Figure 4 depicts the results for optimal location of a small generator with regard to reducing peak load losses. The darkest-colored bus locations represent the top 25% with respect to loss reduction. The lightest color represents the lowest 50%.

Loss improvement varied from slightly less than zero (increase in losses) to almost 8% of the generator's capacity (max of 8 kW loss reduction for a 100 kW generator) depending on location. Eight percent is a moderate incremental loss reduction for the first generator. Many more constrained distribution systems have incremental losses more than 15%. There is a high marginal improvement for the first small generator with respect to losses – if it is in the right place. Then the marginal improvement declines for subsequent generators added in the same general area.

Figure 4: Optimal Locations For Small Generation (100 Kw) On The SMUD System With Respect To Reducing Peak Load Losses

The analysis was repeated for both a medium (1 MW) and a large generator (5 MW). As shown in Figure 5, the 1,000 kW generator produced virtually the same results as the 100 kW generator with respect to loss reduction, indicating that the feeders are relatively short and there is little difference between 100 kW and 1,000 kW at a particular site. On a system with longer feeders, placing a 1,000 kW generator farther out on the feeder will often result in a more noticeable difference.

Figure 5. Optimal Locations For 1,000 Kw Generation On SMUD Area B System With Respect To Reducing Peak Load Losses

The 5 MW generator, shown in Figure 6, results in some slight differences in optimal locations from the other two cases, but is still similar. A few buses where generation may be a bit too large drop out of the top 25% while a few buses on more heavily loaded sections rise to the top 25%. The incremental loss reduction for this large of generator is no longer near 8%. It is 3.7% (of 5,000 kW). Thus, while the plots look similar, the color scale is not the same as the previous two plots.

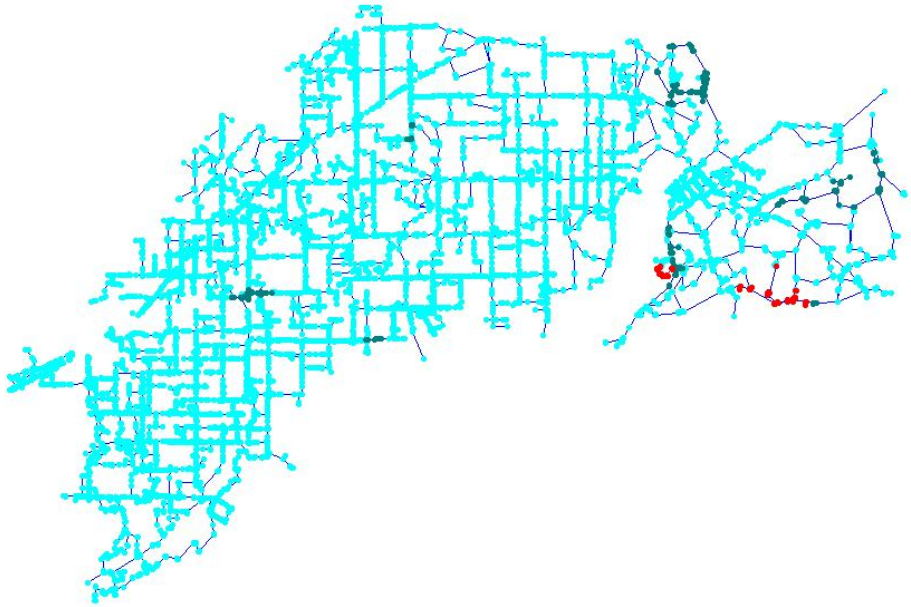

Figure 6. Optimal Locations For 5,000 Kw Generation On SMUD Area B System With Respect To Reducing Peak Load Losses

For more detailed discussion of the engineering screening results, including released capacity from DG results, see the engineering screening analysis chapter

1.5.2. Economic Screening Analysis

We calculated the cost-effectiveness of each RDG technology by comparing lifecycle benefits and costs for each of the applicable tests on an NPV basis, as described in the economic screening chapter. A Benefit/Cost (B/C) ratio greater than 1.0 indicates that the alternative has a lifecycle benefit greater than its lifecycle cost and would therefore pass our initial economic screen.

The B/C ratio results calculated for four economic perspectives including (1) Total Resource Cost Test, (2) Participant Cost Test, (3) Ratepayer Impact Measure Test, and (4) Utility Cost Test are summarized in Table 1. The TRC calculates the net direct economic impact to the community of RDG installation and the Participant cost test measures the cost-effectiveness as if the Participant owns the RDG. The UCT is calculated assuming the RDG is utility-owned, while the RIM is calculated assuming the RDG is owned by the customer (refer to Economic Screening Memo for a more complete description of these cost tests). RDG technologies with a B/C ratio greater than 1.0 are cost-effective. Those with a B/C ratio close to 1.0 may warrant further evaluation. It can be seen from these results that no technologies pass the TRC test or the RIM test. There are two technologies that pass the Participant test and both are combined heat and power (CHP) biogas units that yield high bill savings for the customer.

Table 1: Benefit/Cost Ratio Results For SMUD RDG Screening Analysis

(Using Base-Case Economic Assumptions)

	TRC Cost Test	Participant (Customer or Merchant)	RIM Test (Customer Owned)	UCT Test (Utility Owned)
Biogas - 10kW PEM Fuel Cell	0.03	0.03	0.81	0.03
Biogas - 10kW PEM Fuel Cell CHP	0.36	0.41	0.73	0.31
Biogas - 100kW SOFC Fuel Cell	0.05	0.05	0.81	0.05
Biogas - 100kW SOFC Fuel Cell CHP	0.49	0.56	0.73	0.41
Biogas - 200kW PAFC Fuel Cell	0.04	0.04	0.81	0.04
Biogas - 200kW PAFC Fuel Cell CHP	0.43	0.50	0.73	0.37
Biogas - 200kW PEM Fuel Cell	0.05	0.05	0.81	0.05
Biogas - 200kW PEM Fuel Cell CHP	0.48	0.55	0.73	0.41
Biogas - 250kW MCFC Fuel Cell	0.04	0.04	0.81	0.03
Biogas - 250kW MCFC Fuel Cell CHP	0.37	0.42	0.73	0.31
Biogas - 30 kW Capstone 330 Microturbine	0.07	0.07	0.81	0.07
Biogas - 30 kW Capstone 330 Microturbine w/ CHP	0.58	0.66	0.73	0.48
Biogas - 500 kW Gas Recip GA-K-500	0.14	0.14	0.81	0.12
Biogas - 800kW Caterpillar G3516 LE	0.19	0.20	0.81	0.18
Biogas - 800kW Caterpillar G3516 LE w/CHP	0.95	**1.09**	0.73	0.76
Biogas - 3MW Caterpillar G3616 LE	0.20	0.20	0.81	0.18
Biogas - 3MW Caterpillar G3616 LE w/CHP	0.97	**1.12**	0.73	0.77
Biogas - 5MW Wartsila 5238 LN	0.66	0.75	0.73	0.50
Biogas - MSW Gassification	0.42	0.35		0.50
Biodiesel - 500kW DE-K-500	0.74	0.81	0.75	0.54
Solar - PV-2 kW	0.15	0.19	0.58	0.15
Solar - PV-30 kW	0.17	0.14	0.89	0.17
Solar - PV-200 kW	0.25	0.19	0.95	0.25
Solar - Thermal SAIC SunDish 25 kW	0.15	0.14		0.24
Wind - Bergey WD -10kW	0.10	0.12	0.73	0.10
Wind - GE 750 kW	0.39	0.39		0.62
Wind - GE 1.5 MW	0.46	0.46		0.73

For each of the technologies in Table 1, we analyzed the sensitivity of results to uncertainties in the underlying assumptions. Figure 7 shows an example: the range of the TRC test results (net benefits) for the biogas 5 MW generator in $/kW for six key variables. This range shows that while the net benefit is negative under the base case scenario, changes in these key variables can lead to a cost-effective result with either the High transmission cost or Low fuel cost scenario.

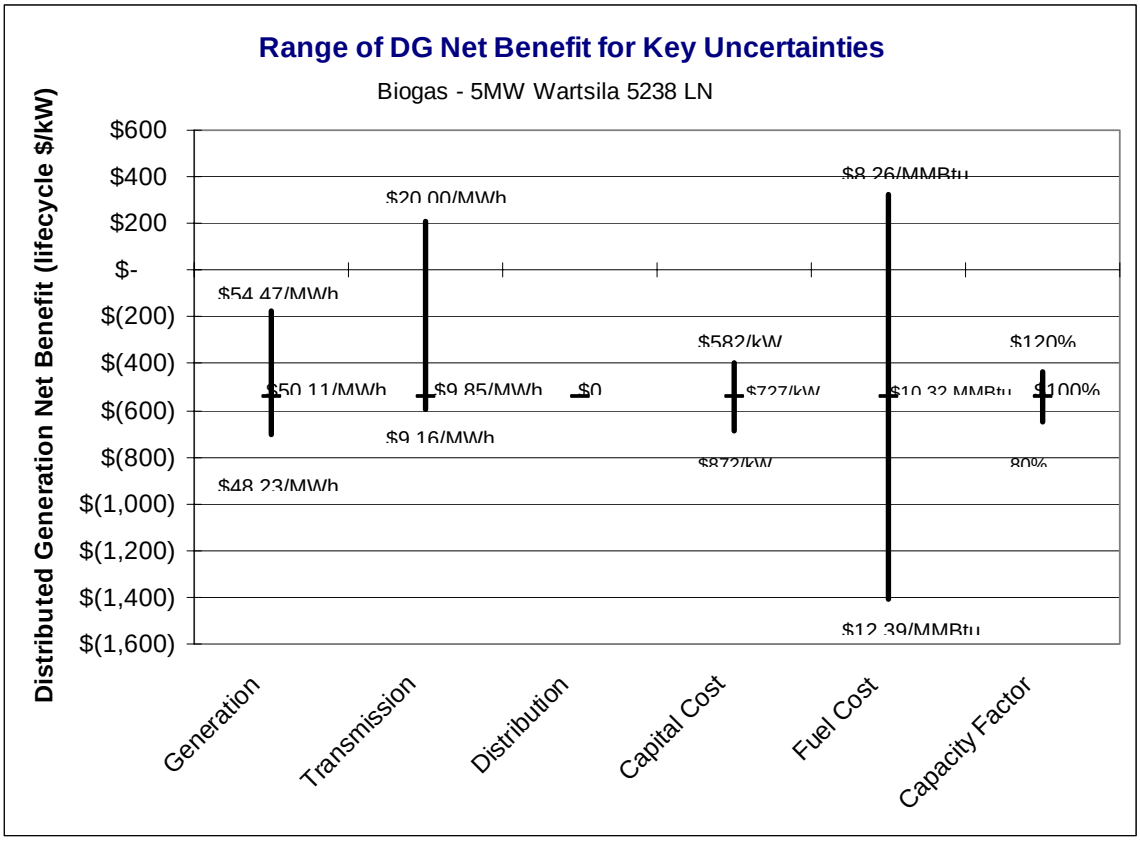

Figure 7: Net Benefit Range For Key Uncertainties From The TRC Test Perspective

For a more detailed discussion of the economic screening results and the sensitivity analysis, see the economic screening chapter and the uncertainty analysis chapter.

2.0 Economic Screening Analysis

The aim of our renewable distributed generation (RDG) analysis is to identify technologies that hold the potential for cost-effective installation in the Sacramento Municipal Utility District (SMUD) service territory. For the purposes of this analysis, RDG is deemed cost-effective if it yields positive net benefits:

Net Benefits = Benefits – Costs

A major component of the benefits associated with RDG in the above equation is comprised of avoided costs, which are the sole subject of this memo. We recognize there are many other benefits that may result from RDG installation, such as indirect environmental benefits, and these are discussed in the economic screening section. Also discussed in the economic screening section are the many perspectives from which one can evaluate the cost-effectiveness of RDG.

Avoided costs, aptly named, are the costs that a utility can avoid incurring by taking an action under consideration, such as installing RDG technology. Thus, avoided costs can be thought of as the benchmark for cost-effectiveness evaluation of RDG technologies. If the avoided costs are greater than the cost of RDG, the RDG technology is cost-effective for that application.

In this section, we focus on the methodology for determining avoided costs and present the results of our analysis of several potential avoided costs including generation, distribution, and transmission components within SMUD's service territory. The actual comparison of benefits (avoided costs and other benefits) and costs (installed and operating costs of RDG) are addressed in the next section which describes the economic screening analysis

This section is organized as follows:

1. General Avoided Cost Methodology
2. Generation Avoided Costs
3. Transmission Avoided Costs
4. Distribution Avoided Costs

2.1. General Avoided Cost Methodology

Throughout this analysis, we have drawn on information obtained from both SMUD and publicly available data sources to calculate avoided costs within SMUD's service territory. The energy commodity purchases, transmission costs, and infrastructure expansions that can be displaced as a result of the installation of RDG within (or close to) SMUD's service territory make up the bulk of the avoided costs. Solar photovoltaic DG, for example, may reduce the utility's energy purchases from the market, reduce associated transmission costs, and defer load growth-related expansion of the system.

Avoided costs vary by both location and time, as each area may have different load, load growth, capacity limitations, and planned investments, and these characteristics vary over time. Avoided costs are highest in capacity constrained areas with near-term expansion plans because the cost of the planned expansion project may be deferred by the installation of RDG. Where a local system has recently been expanded to provide adequate capacity to meet growth, avoided costs will be lower since meeting load with RDG would have no immediate effect on deferring distribution expansion.

We describe our specific methodology and results for generation, transmission, and distribution avoided costs in the sections below.

2.2. Generation Avoided Costs

2.2.1. Generation Avoided Costs Methodology

Avoided generation costs are the reduced market electricity purchase costs, or increased market sales, that result from the installation of RDG. The most appropriate source of data for estimating avoided costs, when available, is forward market prices. When a utility is short, it must purchase its excess energy needs on the market. In this case, new RDG would allow the utility to avoid these market purchases. When a utility is long, it sells its excess generation into the market at either a loss or a gain. [2] In this case, new RDG allows the utility to increase sales of excess energy into the market. Either way, the generation avoided cost value of RDG is represented by market prices.

Electricity forward market price quotes are currently available through Platts' Megawatt Daily through 2006, and these make up the initial basis of our estimate for avoided generation costs. In the absence of forward price quotes for electricity beyond 2006, our forecast relies on gas futures and Long Run Marginal Costs (LRMC), as shown in Table 2, and each forecast component is described in greater detail below.

Table 2: Avoided Generation Cost Forecast Method By Period

Period	Generation Cost Forecast Method
2004 -2006	Electricity Forward Price Quotes
2007	Gas Futures and Heat Rate
2008 and Beyond	Long Run Marginal Cost (LRMC)

Any electricity price forecast may be substituted for our avoided costs forecast, though care should be taken to ensure the price reflects delivery to the SMUD system. Broker quotes offered directly to SMUD are an excellent substitute for our avoided generation

[2] The utility is 'short' when it has purchased less than 100% of its energy requirement in the forward market and is 'long' when it has purchased more than 100%.

forecast for all years in which they are available. Generation market prices could be updated with broker quotes and other information available to SMUD.

2.2.1.1. Electricity Forward Market Price Quotes: 2004 – 2006

Through 2006, we base our market price forecast on forward price quotes from Platts' Megawatt Daily. The price quotes reported by Platts are for the peak period. We estimate the off-peak price to be 67% of the on-peak price, based on an historical relationship between peak and off-peak spot market prices. [3]

2.2.1.2. Gas Price and Heat Rate of CCGT: 2007

When forward price quotes are unavailable, Long-Run Marginal Cost (LRMC) may be used to forecast electricity prices, as described below. The LRMC method, however, assumes that the electricity system is in load and resource balance (meaning available generation is just able to meet demand plus reserve margin). California is currently in a period of excess supply; therefore, using the LRMC method would produce forecast prices that are too high in the short term, as they do not take into consideration this excess capacity.

In a competitive market with excess supply, the price of electricity should equal the marginal cost of producing it. So, one way around this price discrepancy is to observe the implied heat rate of the marginal generating unit. For a gas fired generator, the marginal cost of production is determined by the gas price and the heat rate of the generator. Therefore, we are able to calculate the implied heat rate for the marginal generating unit in 2006, when market prices for both gas futures and electricity forwards are available.

We then make the assumption that while excess generation capacity remains – in 2007 – this heat rate will hold. Now we can use the heat rate and gas market price (available through 2009) to derive an electricity price.

2.2.1.3. Long Run Marginal Cost: 2008 and Beyond

In a period of system load and resource balance with a competitive marketplace for generation the price of electricity can be expected to equal the Long Run Marginal Cost (LRMC) of production. For our forecast, we accept the CEC projection of system load and resource balance in 2008. We assume the LRMC will be equal to the full cost of operating a combined cycle gas fired generator (CCGT). We chose CCGT as a proxy for LRMC because natural gas makes up the vast majority of planned plant additions in California and CCGT plants are the dominant technology at present.

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[3] We used California Power Exchange data from April 1998 through April 2000 to calculate the estimated peak/off-peak price relationship.

Our assumptions regarding CCGT operating cost and performance were obtained from a CEC August 2003 staff report. [4] A key driver of CCGT cost is, of course, the cost of gas. We rely on NYMEX natural gas futures, which are available through 2009, and the CEC's gas forecast beyond 2009 for our gas price estimates.

2.2.2. Generation Avoided Cost Results

Taken together, the three electricity price period components described above comprise the electricity price forecast used to calculate the generation avoided cost results. Table 3 shows the first 10 years of generation avoided cost inputs in E3's screening model. This is a direct relationship whereby the actual market price of electricity equals the costs avoided through the acquisition of RDG resources. The data represent E3's base case electricity price forecast, calculated as described above.

Table 3: Screening Model Generation Avoided Cost Inputs

Wholesale Energy Forecast (Nominal $/MWh)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak	$50.47	$52.32	$52.82	$51.42	$60.70	$66.88	$62.02	$64.15	$66.18	$68.56	$70.92	$73.35
Off-Peak	$33.81	$35.06	$35.39	$34.45	$40.67	$44.81	$41.55	$42.98	$44.34	$45.93	$47.51	$49.15

Table 4 shows the definition of the two TOU periods we have used in the model, which correspond to the peak and off-peak pricing periods in the forward electricity market quoted by Platts.

Table 4: Time-Of-Use Period Definitions

TOU Period	Definition	# of Hours in Period	% of Hours in Period
Peak	Mon-Sat, 6:00 AM to 10:00 PM (6x16), except holidays	4864	56%
Off-Peak	All other hours	3896	44%

Generation avoided costs are shown in Figure 8 along with the 20-year levelized stream for both the peak and off-peak periods.

[4] "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Appendix D and Assumptions for Equity Return and Debt Interest Rates, Table 2.

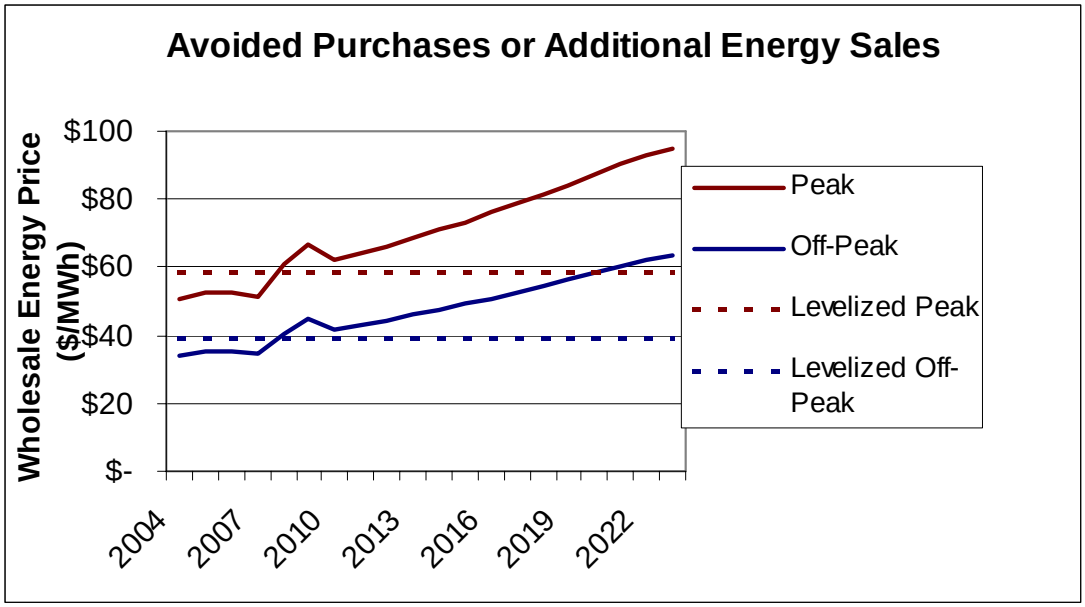

Figure 8: Avoided Generation Costs

All avoided costs are in nominal dollars. The 20-year levelized values in Figure 8 are the level payments required to produce the same total cost as the non-levelized stream, given the SMUD's discount rate. This value is $58.52/MWh in the peak period and $39.21/MWh in the off-peak period.

In Table 3 and Figure 8, one can observe a slight dip in forecast prices in 2007. This is a result of gas futures prices being lower for 2007 than for 2006. There is another, larger dip in 2010. Since gas futures are available only through 2009, beginning in 2010 we use the CEC gas price forecast, which is low compared to recent gas futures prices.

We also calculated 'high' and 'low' price scenarios for avoided generation costs. In our base case forecast, electricity prices for the years 2004 – 2009 are given by either forward electricity prices or natural gas futures prices and the cost of production. Since these are forward contracts that a utility can buy, the forecast represents a fully hedged position. For this reason, we hold the first five years of the forecast constant for the base case, high, and low scenarios. After 2009, when the forecast is based on the CEC's gas forecast and the cost of production, we use the CEC's high and low gas price forecasts to calculate our high and low electricity price forecast. As with the base case, the price is based on the full cost of operating a CCGT.

The base, high, and low avoided generation cost scenarios are shown in Figure 9.

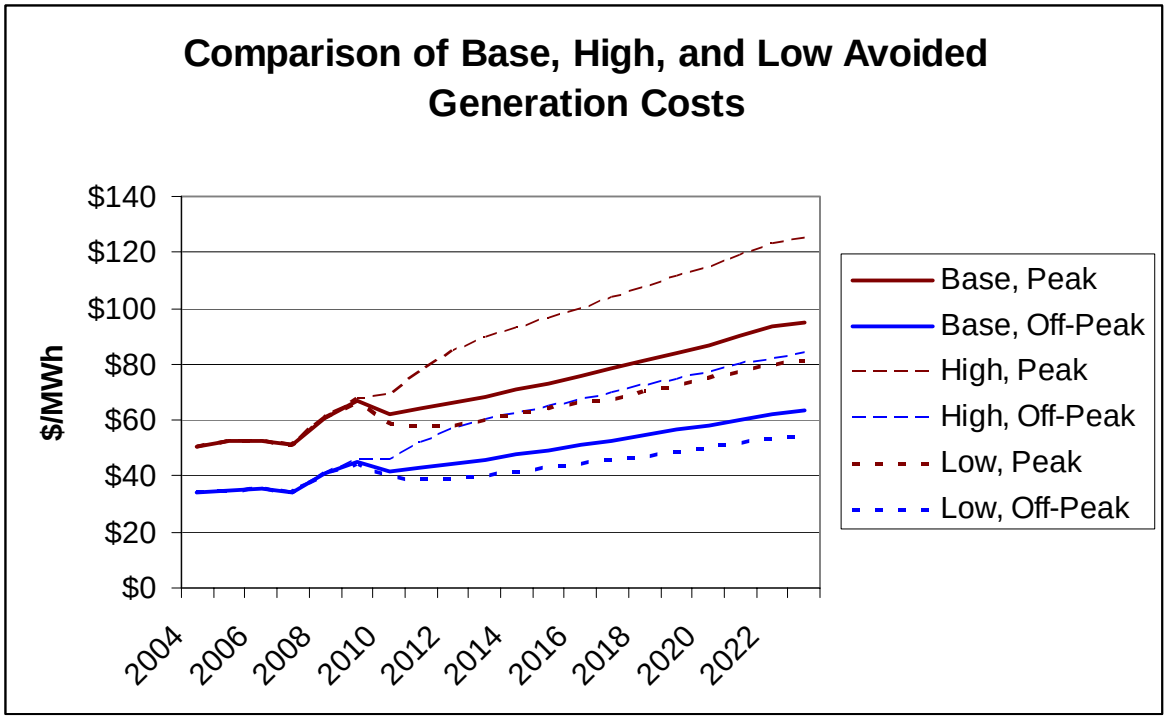

Figure 9: Comparison Of Base, High, And Low Scenarios For Avoided Generation Costs

In the uncertainty analysis chapter, we discuss the sensitivity of benefit-cost analysis results to the high and low scenarios shown above.

2.3. Transmission Avoided Costs

2.3.1. Transmission Avoided Costs Methodology

Transmission avoided costs, for a UDC such as SMUD, consist of transmission charges paid to other entities that the utility would not have to pay if it had sufficient in-area generation to meet its load.[5]

Transmission avoided costs for a larger utility responsible for construction, operation, and maintenance of a portion of the transmission system could be calculated using the PW method as described in the distribution avoided costs methodology below. However, since the municipal distribution utility jurisdiction does not include transmission

[5] This assumes transmission service is based, as it currently is, on net usage, meaning the amount of energy the utility takes through the transmission system (gross consumption net of any in-area generation). If transmission charges are based on *gross* usage, in area generation would be added back in for calculation of transmission charges, and no transmission avoided costs would ensue from DG.

investments, we simply apply the actual transmission charges paid to import power onto the local distribution system.

2.3.2. Transmission Avoided Cost Results

We estimate SMUD's transmission charges to be $2.22/MWh. This represents the California ISO's High Voltage Wheeling charges, which are the marginal avoidable transmission charges for SMUD. This estimate is held constant over the life of the analysis to make up our base case and low scenarios.

The 'high' scenario reflects the uncertainty of a possible move to Locational Marginal Pricing (LMP), proposed by the California ISO for implementation in 2005. Under LMP, the price of energy would reflect congestion on the grid, and the transmission charge would effectively become the energy price differential between points on the grid. The effects of a move to LMP are difficult to estimate, as the rules for the new market have not yet been established. We have assumed a value of $15/MWh to reasonably represent an upper bound of transmission costs under this scenario. Additional detail on the sensitivity testing results is provided in the uncertainty analysis chapter.

2.4. Distribution Avoided Costs

2.4.1. Distribution Avoided Costs Methodology

Distribution avoided costs result when peak loads are kept below a threshold level that would otherwise trigger a distribution investment. Distribution avoided costs are often referred to as the 'deferral value' of a planned capital project. Since the cost of capital is higher than the inflation rate, the postponement of a capital project into the future results in a positive deferral value or an avoided cost value. We use an evaluation method called the Present Worth (PW) method to calculate the deferral value (distribution avoided costs).

Under the PW method, the utility's revenue requirement under the base case plan (no RDG) is compared with the plan with RDG on a present value basis. We use the term 'revenue requirement' to stress that it is not just the engineering costs of each case that are compared, but the fully loaded project costs, including maintenance, administrative costs, insurance, and any other relevant project costs. However, the fully loaded project costs exclude any 'unavoidable' or non-deferrable costs such as land acquisition costs.

The expression of the PW formula used to calculate the distribution avoided cost is shown in Equation 1. The results from this calculation provide a $/MW-year value for distribution avoided costs.

$$MC[PW] = \frac{\sum \left[\frac{Invest}{(1+r)^{y}} - \frac{Invest * (1+i)^{\Delta y}}{(1+r)^{y+\Delta y}} \right]}{LoadChange} * AnnualizationFactor$$

where:

Invest = annual demand-related investments in capacity by area ($)

i = escalation rate for the investments

r = discount rate; *y* = year

LoadChange = estimated average change in peak load by area for the planning period

Δy = deferral caused by load change (annual peak load growth divided by *LoadChange*)

Annualization Factor = real economic carrying charge for the planning period, grossed up by a variable expense factor

We use a spreadsheet-based model to calculate the specific avoided cost values relevant to SMUD. The basic model inputs are shown in Table 5.

Table 5: Distribution Avoided Cost Calculation Inputs

Model Input	Unit	Additional Information
Planned investments	$	For this analysis, our focus has been on local distribution investments. If generation or transmission projects could impact local avoided costs, we would incorporate those as well.
Timing of investments	Year/Month	This is the time period within which the decision to build or not-build would be made as well as the required in-service date for the project.
Minimum load deferral amount	MW	The minimum amount of load that needs to be deferred through an alternative option to avoid construction of the base-case project.
Load growth forecast	MW/year	We often use a base case forecast to calculate avoided costs, but also evaluating both high and low estimates can be useful in the decision-making process.
Investment discount rate	%	This is the discount rate used by the local distribution company for investment also known as the weighted average cost of capital (WACC).
Interest rate	%	This should be the interest rate that is used in internal investment evaluations.

2.4.2. Distribution Avoided Cost Results

SMUD distribution engineering staff provided plans for distribution capacity projects within Area B over the next five years. In coordination with SMUD engineers, we were able to identify only one distribution capacity project that could potentially be deferred through the installation of RDG. All the other capacity related projects planned in Area B are required to serve new or 'greenfield' developments and cannot be deferred or offset. The project identified as potentially deferrable – the addition of a second bank at the Sylvan-Auburn substation – is currently scheduled for construction in the 2009 – 2010 period. The total costs estimated for this project are approximately $1 million; however, only $500,000 could be deferred.[6] The remaining costs, such as land purchase and basic facility, would be incurred regardless of RDG installation to insure facilities are available for future expansion.

[6] The avoided engineering costs are increased by 30% to represent fully-loaded project costs.

Figure 10 shows the results of the avoided distribution costs analysis for the Sylvan-Auburn project. The levelized avoided costs reflect the value of the deferral on a per-kW of RDG basis, and take into consideration the number of kW of RDG that would be required each year to allow deferral.

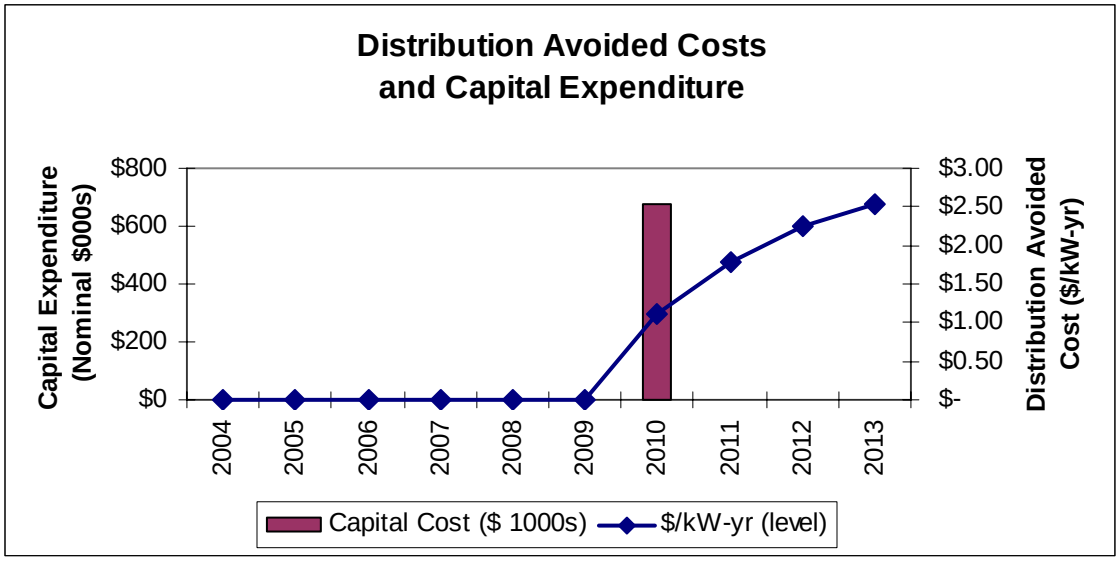

Figure 10: SMUD Area B Distribution Avoided Costs Resulting From Deferral Of Sylvan-Auburn Substation Second Bank

If this project were deferred for one year, the value would be $1.10/kW-year; if deferred for two years, the value would be $1.80/kW-year. These values represent the discounted values and assume that the RDG is installed in 2004 and the deferral avoided cost value is realized in 2010. Since there were no deferrable projects identified in earlier years, this one project represents a relatively small distribution avoided cost value.

2.5. RDG Economic Screening

In this section, we incorporate the results described in the avoided cost section to further develop the RDG economic analysis. The avoided costs are one element of the total benefits of RDG installation. In order to determine the overall cost-effectiveness of RDG, we compare the total benefits compared to total costs of RDG as in this simplified calculation.

Net Benefits = Benefits – Costs

In this section, we provide a description of the inputs, methodology, and results from our analysis of multiple RDG technologies that could be installed within or nearby the SMUD service territory.

The approach we take to evaluating potential RDG involves determining the cost-effectiveness of each technology from several different perspectives (e.g. RDG owner, utility, customer, and society). Specifically, we evaluated cost effectiveness from the perspective of five established 'cost tests':

1. Participant Cost Test. This test measures the economic impact to the DG owner.
2. Ratepayer Impact Measure (RIM). This test measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels of margin if a customer installed RDG.
3. Utility Cost Test (UCT). This test measures the change in the amount the utility must collect from the customers every year.
4. Total Resource Cost Test (TRC). This test measures the net direct economic impact to the community.
5. Societal Cost Test. This test measures the net economic benefit to the community, as measured by the TRC, plus indirect benefits such as environmental benefits.

A common misperception is that there is a single best perspective for evaluation of cost-effectiveness. Each test is accurate, but the results of each test are intended to answer a different set of questions. In our analysis, we evaluate multiple perspectives to paint a more complete picture of the overall RDG project economics. The key questions answered by each cost test are shown in Table 6.

Table 6: Questions Addressed By The Various Cost Tests

Participant Cost Test	Is it worth it to the customer to install DG? Is the customer likely to want to participate in a utility program that promotes DG?
Ratepayer Impact Measure	What is the impact of the DG project on the utility's operating margin? Would the project require an increase in rates to reach the same operating margin?
Utility Cost Test	Do total utility costs increase or decrease? What is the change in total customer bills required to keep the utility whole (the change in revenue requirement)?
Total Resource Cost Test	What is the community benefit of the DG project including the net costs and benefits to the utility and its customers? Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)? Is more or less money required by the community to pay for energy needs?
Societal Cost Test	What is the overall benefit to the community of the DG project, including indirect benefits? Are all of the benefits, including indirect benefits, greater than all of the costs (regardless of who pays the costs and who receives the benefits)?

In Table 7, we list the specific benefit and cost components that are attributed to each cost test perspective in our economic screening. These are the easily identified and typical direct costs and benefits that can be associated with RDG. We have also included a category entitled 'Other Direct Benefits' to capture other specific, measurable benefits that may be identified.

Table 7: Benefits And Costs Of RDG From Five Cost-Effectiveness Test Perspectives Included In Our Modeling

Tests and Perspective	Costs	Benefits
Participant Cost Test	• RDG capital and operating costs	• Participation incentives • Energy sales and/or bill savings • Equipment rebate
Utility Cost Test (UCT) **Distribution Utility as DG Owner**	• RDG capital and operating costs • Siting costs for utility-owned RDG	• Transmission tariff savings • Distribution capacity savings • Energy savings • Voltage support • Other direct benefits, such as lower tipping fees for solid waste
Ratepayer Impact Measure (RIM)	• Revenue loss • Incentive payments • Equipment rebate • Administrative costs	• Transmission tariff savings • Distribution capacity savings • Voltage support • Energy savings
Total Resources Cost Test (TRC)	• RDG capital and operating costs • Administrative costs	• Distribution capacity savings • Energy sales and/or savings • Transmission tariff savings • Other direct benefits, such as lower tipping fees for solid waste
Societal Cost Test	• RDG capital and operating costs • Administrative costs	• Distribution capacity savings • Voltage support • Energy sales and/or savings • Other direct benefits • Transmission tariff savings • Indirect benefits, such as reduced emissions and increased property value

The major difference between the TRC and Societal tests is the inclusion in the Societal test of externalities or indirect benefits such as cleaner air and increased local property values, elements for which a clear price or economic valuation may not exist. To avoid diluting results by mixing these indirect, unpriced values with known, priced values, our methodology relies on a 'gap analysis' to evaluate the Societal test perspective. The gap analysis measures direct benefits against direct costs and weighs the economic 'gap,' if any, against a list of indirect benefits. We discuss the gap analysis in more detail in the indirect benefits section.

2.5.1. Calculation of Benefits and Costs

This section describes in greater detail our methodology for calculating the benefits and costs that enter into the cost tests described above. We have made an effort to simplify the inherent complexity in some of the inputs and calculations for ease of use but only if these simplifications do not affect the robustness of the results. In every case, we calculate the net present value (NPV) of the stream of costs and benefits, based on the discount rate appropriate to the test perspective, and compare the two. Our results are presented on an NPV basis.

2.5.1.1. Costs of RDG

For the Participant, TRC, and Utility (assuming utility RDG Ownership) test perspectives, the costs of RDG comprise the capital, fuel, and O&M (fixed and variable) costs of the RDG technology under evaluation. Table 8 shows the key RDG performance characteristics and cost data we used in our analysis. We used publicly available information on commercially available technologies. Additional information on RDG technologies is available in Appendix A.

For the RIM test perspective, RDG capital and operating costs are excluded since these costs are borne by the participant and have no impact on the utility's rates or operating margin. Instead, costs in the RIM test include lost revenues due to reductions in the participant's energy bill. The RIM test also includes as costs any incentives paid by the utility to participants and any administrative costs associated with a utility DG program.

Table 8: RDG Performance Characteristics

Technology Name	Generator Life (Years)	Fuel Type: (1)No Cost (solar, hydro, wind) (2) Biodiesel 80/20 (3) MSW Delivery and Process. $/MMBtu (4) Landfill Gas (5) Renewable Fuel #5	Heat Rate (Net Heat Rate for CHP Applications)	Capital Cost $/kW	Fixed O&M $/kW-yr	Variable O&M $/kWh
Biogas - 10kW PEM Fuel Cell	10	4	11,370	$5,500	$18.00	$0.03
Biogas - 10kW PEM Fuel Cell CHP	10	4	6,370	$5,500	$18.00	$0.03
Biogas - 100kW SOFC Fuel Cell	10	4	8,338	$3,500	$10.00	$0.02
Biogas - 100kW SOFC Fuel Cell CHP	10	4	5,731	$3,500	$10.00	$0.02
Biogas - 200kW PAFC Fuel Cell	10	4	9,480	$4,500	$6.50	$0.03
Biogas - 200kW PAFC Fuel Cell CHP	10	4	5,105	$4,500	$6.50	$0.03
Biogas - 200kW PEM Fuel Cell	10	4	10,725	$3,600	$6.50	$0.02
Biogas - 200kW PEM Fuel Cell CHP	10	4	5,775	$3,600	$6.50	$0.02
Biogas - 250kW MCFC Fuel Cell	10	4	7,930	$5,000	$5.00	$0.04
Biogas - 250kW MCFC Fuel Cell CHP	10	4	5,730	$5,000	$5.00	$0.04
Biogas - 30 kW Capstone 330 Microturbine	10	4	15,070	$2,260	$0.00	$0.02
Biogas - 30 kW Capstone 330 Microturbine w/ CHP	10	4	5,434	$2,630	$0.00	$0.02
Biogas - 500 kW Gas Recip GA-K-500	10	4	12,003	$936	$26.50	$0.00
Biogas - 800kW Caterpillar G3516 LE	10	4	10,246	$724	$0.00	$0.01
Biogas - 800kW Caterpillar G3516 LE w/CHP	10	4	4,771	$971	$0.00	$0.01
Biogas - 3MW Caterpillar G3616 LE	10	4	9,492	$702	$0.00	$0.01
Biogas - 3MW Caterpillar G3616 LE w/CHP	10	4	4,857	$864	$0.00	$0.01
Biogas - 5MW Wartsila 5238 LN	10	4	8,758	$727	$0.00	$0.01
Biogas - MSW Gassification	15	3	8,000	$5,179	$20.00	$0.00
Biodiesel - 500kW DE-K-500	12.5	2	10,314	$386	$26.50	$0.00
Solar - PV-2 kW	20	1	-	$9,390	$14.30	$0.00
Solar - PV-30 kW	20	1	-	$8,550	$5.00	$0.00
Solar - PV-200 kW	30	1	-	$6,980	$2.85	$0.00
Solar - Thermal SAIC SunDish 25 kW	20	1	-	$5,700	$20.00	$0.00
Wind - Bergey WD -10kW	10	1	-	$6,055	$5.70	$0.00
Wind - GE 750 kW	20	1	-	$1,200	$15.00	$0.00
Wind - GE 1.5 MW	20	1	-	$1,000	$15.00	$0.00

3.0 Engineering Screening Analysis

3.1. Overview

This chapter describes engineering screens performed on the SMUD distribution system to estimate the feasibility of accommodating distributed generation and the potential value of that generation to the benefit of the power delivery system. A particular emphasis is given to renewable generation.

The system being studied here is known as SMUD Area B. It consists of approximately 700 MW of load with peak losses in the 12 kV distribution system of 10.5 MW (1.5%). It is an area approximately 17 miles in width and is rather uniformly covered with substations having relatively short feeders of one to two miles. For the most part, losses are relatively low with a few areas having incremental losses as high as 8%.

The analysis was performed in three steps:

1. Determine the area power flow characteristics
2. Perform a distributed generation (DG) siting analysis for the area
3. Perform operational feasibility analysis for proposed cases

The area was evaluated for the best areas to add small, medium and large sized generation with respect to losses and released capacity. The sizes were represented by 100 kW, 1000 kW and 5000 kW generators, respectively.

Three reference cases were developed:

1. 13.5 MW of generation sited for optimal loss reduction
2. 13.5 MW of generation sited for optimal released feeder capacity
3. 20 MW of solar PV generation dispersed over the area

Operation feasibility screens were performed for each of these cases. No likely problems were indicated for these DG configurations. Considerably more generation can likely be accommodated in Area B without requiring costly changes to the distribution system, provided it is not more heavily concentrated than in the reference cases developed here.

Reference Case 1 achieves a net incremental peak loss reduction of 5% for 13.5 MW of generation. The first few generators added can achieve up to 8% incremental peak loss reduction. More widely dispersed generation sited at random, such as Reference Case 3, can be expected to contribute only 2% peak loss reduction. Reference Case 2 is somewhat less effective in reducing losses than Reference Case 1, but should prove to be more effective in releasing feeder capacity for reliability improvement. (Incremental loss reduction is defined as the percentage of the loss reduction relative to the amount of generation added.)

Impact on annual energy and capacity values will be evaluated in the Reliability Chapter yet to follow.

3.2. Description of Analysis

This section describes the work performed to gain an understanding of the essential electrical characteristics of the system and to evaluate the feasibility of distributed generation (DG) alternatives from an engineering perspective. A model of the primary distribution system was constructed in Electrotek's Distribution System Simulator (DSS), which was used to perform the analysis described herein.

The steps in the analysis are:

1. Generate graphics of the power flow in the system. This allows us to rapidly gain an understanding of the system and begin to understand where there might be some opportunities for DG.
2. Perform a siting analysis for various sizes of generation. This determines where the most benefits to the distribution system are likely to be obtained.
3. Evaluate a range of DG schemes for operational feasibility with respect to losses, voltage regulation, and impact on overcurrent protection.

This report is divided into three major sections corresponding to the steps above.

Although it had no specific DG plans to investigate, SMUD has an active program for encouraging the use of solar power. Therefore, one case was developed with 20 MW of PV distributed across the system.

Two other cases were developed by siting generation where it would have the best benefit for either losses or released feeder capacity. This is a common technique we use to determine what might be possible with DG if one had the choice to place the DG where it might best benefit the power delivery system.

For each case, a standard voltage regulation screen and overcurrent contribution screen was executed. These screens are intended to identify cases where the distribution system must be changed to accommodate the DG. Two of the more limiting issues are the amount the voltage changes when the generation is brought on or off the system and the amount of additional fault current contributed by the generation.

3.3. Power Flow Characteristics

Figure 11 shows a typical diagram for the peak-load power flow case for SMUD Area B. The thickness of the lines in this plot is in proportion to the power flowing in the lines. Therefore, the main feeders are clearly visible. The substation locations can be deduced from the convergence of the thick feeder lines, but are also marked with a red triangle symbol.

This diagram helps the engineer understand how things are connected and whether there are any likely problem areas that might be addressed by DG. The area appears to have a rather uniform distribution of substations with the load relatively well distributed among the stations.

There are 52 transformers represented in this model (some substations have more than one transformer). The model consists mainly of the 12 kV lines. There is a 69 kV equivalent at each substation, but the 69 kV system is not represented in detail. Therefore, the impact of DG on the transmission system is not included in this analysis. The benefits identified in this report are strictly related to the 12 kV primary distribution system.

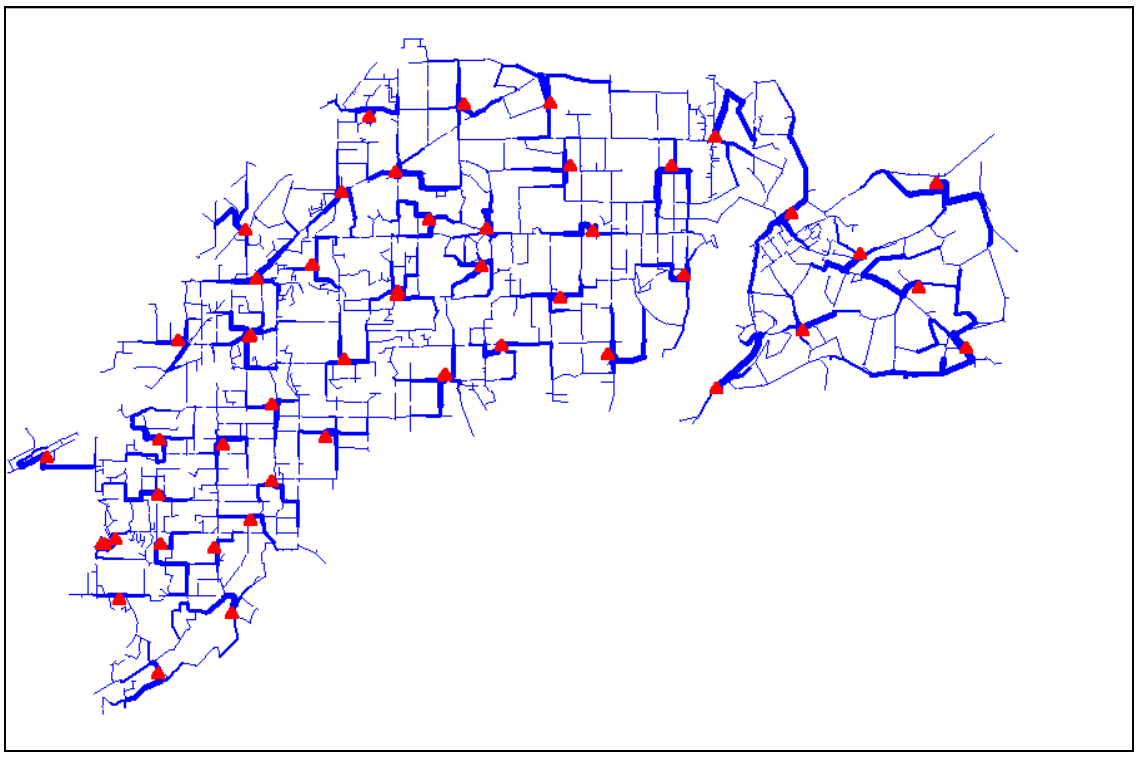

Figure 11: Power Flow Diagram For Area B

The system model consists of over 8,800 buses and approximately 700 MW of load. The data for the line impedances and loading were extracted from a Microsoft Access database used by the Stoner SynerGEE program. This program is used by SMUD engineers for planning and analyzing the distribution system. When the model was first received, it contained descriptions of some substations on the fringe of the area shown in Figure 11. It was unclear whether these models were complete, so they were stripped out of the model built in the DSS.

Figure 12 shows a partial map of Area B corresponding to approximately the right half of the power flow diagram in Figure 11. As might be expected, the feeder lines and street lines are coincident in most cases. This area is approximately 17 miles from left to right.

The typical distance between substations would appear to be one to two miles. The substations are well distributed across the area and the feeder lengths are short relative to feeders in more rural areas. This results in a more efficient power delivery system than found in other utilities that might use longer average feeder lengths. This observation is borne out in some of the calculations performed in this report.

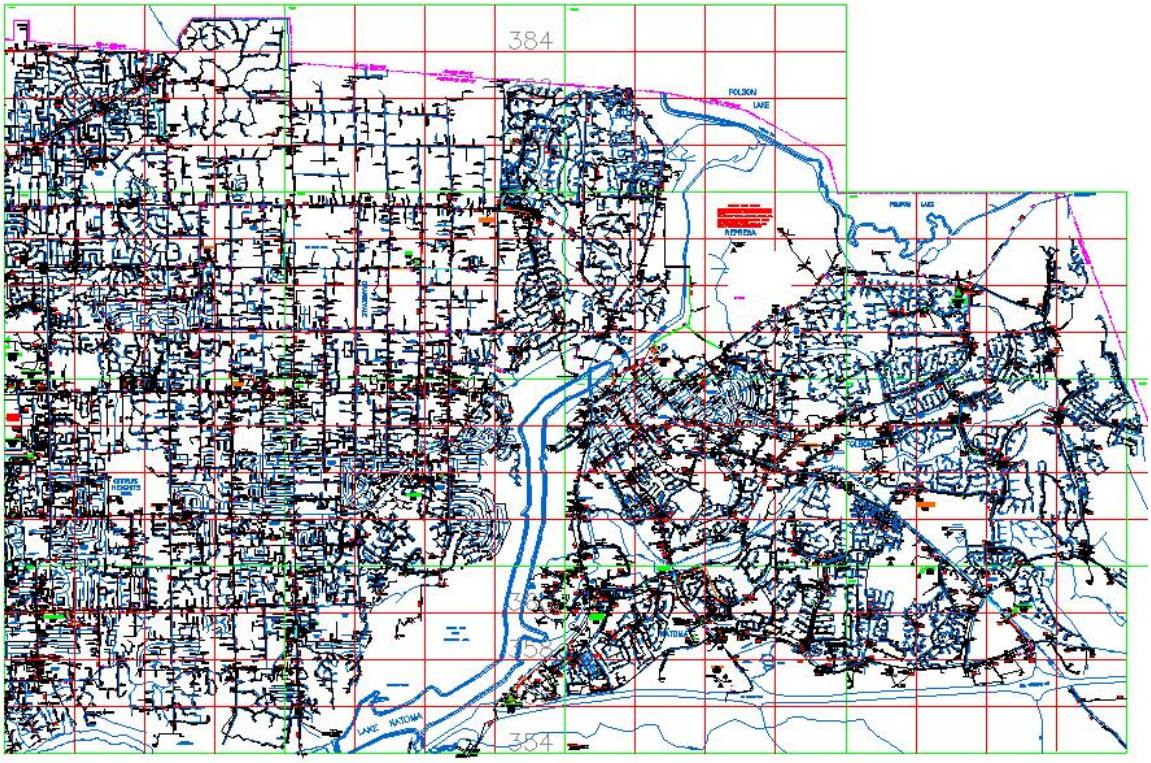

Figure 12: Partial Map Of Area B

3.3.1. Losses

To compare the DG options, we need to first establish the base case. One key figure of merit is the peak loss value. For the base model, we compute the losses in the primary distribution system as follows:

Total Active Power: 710.761 MW

Total Active Losses: 10.491 MW, (1.476 %)

This does not include secondary losses and transformer idling (no load) losses. It includes only the losses in the substation transformers and in the 12 kV lines. Secondary losses for typical utility systems might average 4% or more on an annual basis. As of this writing, it is not know what the annual losses are for SMUD as a whole.

From the engineering viewpoint, this value is relatively low compared to other 12 kV systems we have studied.

3.4. DG Siting Analysis

The preceding analysis gives insight into some general system characteristics. However, with the substations scattered rather uniformly throughout the geographical area, it does not give much indication where the generation should be sited for optimal benefits. Benefits from DG to a distribution system are often very site-specific.

The 'optimal' location for DG on distribution systems will depend on what is being optimized and is quite sensitive to the size of generation. This engineering screening approach investigates both small and large unit sizes. The locations identified for small sizes are possible candidates for encouraging solar PV and small CHP applications. The locations identifies for larger sizes would be possible candidates for peaking units, large CHP and baseload applications.

For each unit size, we typically find optimal sets of locations with respect to loss reduction and released feeder capacity. The loss reduction computation is straightforward: simply compare the losses of the various proposed cases. Released capacity is computed in terms of energy exceeding normal (EEN) rating of the feeders. Other criteria could be used in special cases, but were not in this study.

Losses are often an indicator of where the locations with the greatest overall benefit to the system are to be found. While one might expect the loss-optimized locations to improve system efficiency, there is also a relationship between losses and capacity. Therefore, optimizing for minimum losses is often near-optimal for capacity issues as well.

Optimizing strictly on EEN generally highlights locations on feeders that are presently utilizing the greatest percentage of their capacity. This often corresponds to feeders with heavier losses, but not necessarily. No credit is given for reducing capacity below the value established for the normal rating. Therefore, only the lines with peak loading in excess of normal rating are considered candidates for DG in this analysis.

In this study, three sizes of generators were used. A 100 kW test generator was used for the small unit size, a 1,000 kW for a medium-sized generator, and 5,000 kW (5 MW) for the large size. 100 kW is small relative to the capacity of any of the feeders and lateral branches and the results should apply to any small generators. The results for this case give a good idea of the incremental improvement possible with respect to losses or released capacity. 1,000 kW is typically about 15% of a given feeder's capacity and is a common size of DG applied. 5 MW is more than 50% of the capacity of any one feeder and is, therefore, likely about as large of a generator as would be practical without considerable changes to the existing system.

3.4.1. Optimal Locations for Loss Reduction

The first screen is to place the test generator at each bus and then rank the buses based on relieving losses in the distribution system. It should be noted that the result depends on the specific loading assumptions in the model. SMUD could hypothetically vary the

loading relatively easily by changing the switches so that the optimal locations might very well shift to another feeder.

Figure 13 depicts the results of this analysis for a 100 kW test generator. The buses in red (dark on a monochrome print) represent the buses in the top quartile (25%) of the loss reduction range. The buses in green are the next most favorable and light blue (cyan) the least. The cutoff between the cyan and green buses is 50% of the range.

The loss reduction range was from slightly less than zero (a small increase in losses) to almost 8% of the generator's capacity (max of 8 kW loss reduction for a 100 kW generator) depending on location. It is common for the first generator added at peak load to achieve a fairly significant loss reduction – if it is in the right place. Then the improvement declines for other generators added in the same general area (see description of Reference Case 1 below). Eight percent is a moderate incremental loss reduction for the first generator. More constrained distribution systems often have incremental loss improvement of more than 15%.

The vast majority of the buses (cyan) have incremental loss improvements less than 4%. The conclusion is that the power delivery service to most of the area uniform and fairly efficient. There are only a few areas where the incremental losses are computed to be moderately high, as indicated.

Figure 13: Locations In Red Are Most Optimal For 100 Kw Generation On SMUD Area B System With Respect To Reducing Peak Load Losses.

This conclusion is reinforced in Figure 14. Here, the red (darker) circles indicate the buses with incremental loss improvement in the lower quartile. In this case, these are areas where the incremental loss improvement is 2% or less of the generator size. As can be readily seen, these represent the majority of buses.

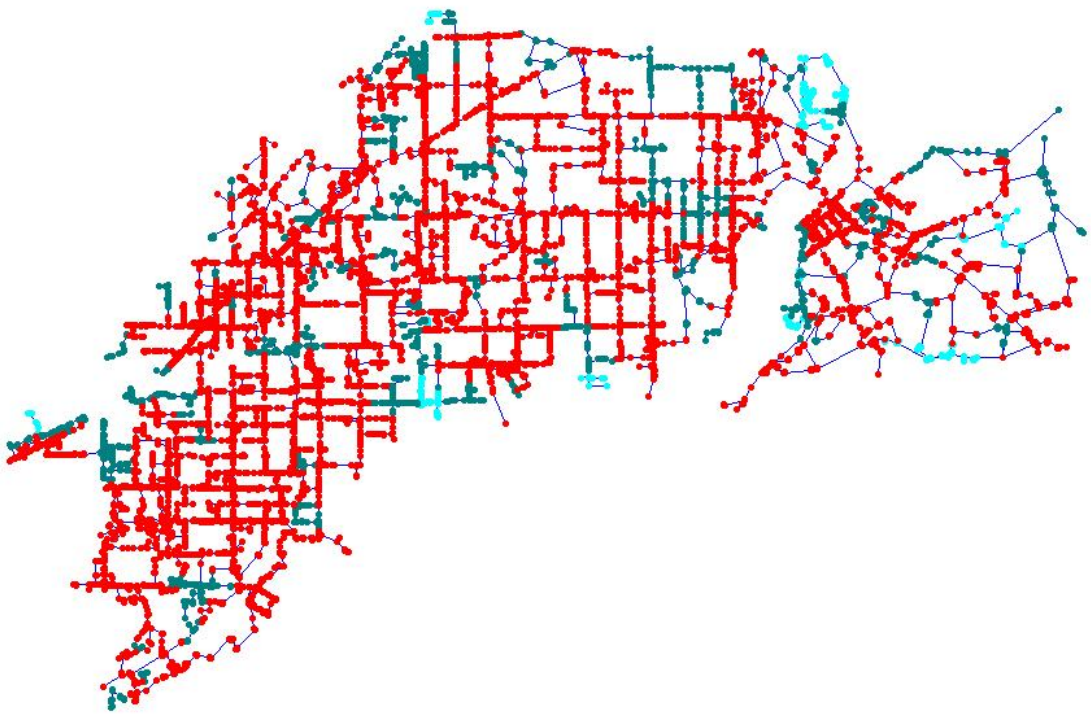

Figure 14: Red Areas Are Least Optimal For Siting 100 Kw Generation With Respect To Loss Reduction.

Figure 15 shows the same plot as Figure 13, except that the test generator size is 1,000 kW. This gives virtually the same result as the 100 kW test generator with respect to loss reduction. This is an indication that the feeders are relatively short and there is little difference between 100 kW and 1,000 kW at a site. On systems with longer feeders, placing 1,000 kW farther out on the feeder will often make a more noticeable difference.

The 5 MW test generator shown in Figure 16 results in some slight differences in optimal locations from the other two cases, but is still similar. A few buses where generation may be a bit too large drop out of the top 25% of the range while a few buses on more heavily loaded sections rise to the top 25%. The incremental loss reduction for this size generator is no longer nearly 8%. It is only 3.7% (of 5,000 kW). Thus, while the plots look similar, the color scale is not the same as the previous two plots.

Figure 15: Optimal Locations For 1,000 Kw Generation On SMUD Area B System With Respect To Reducing Peak Load Losses

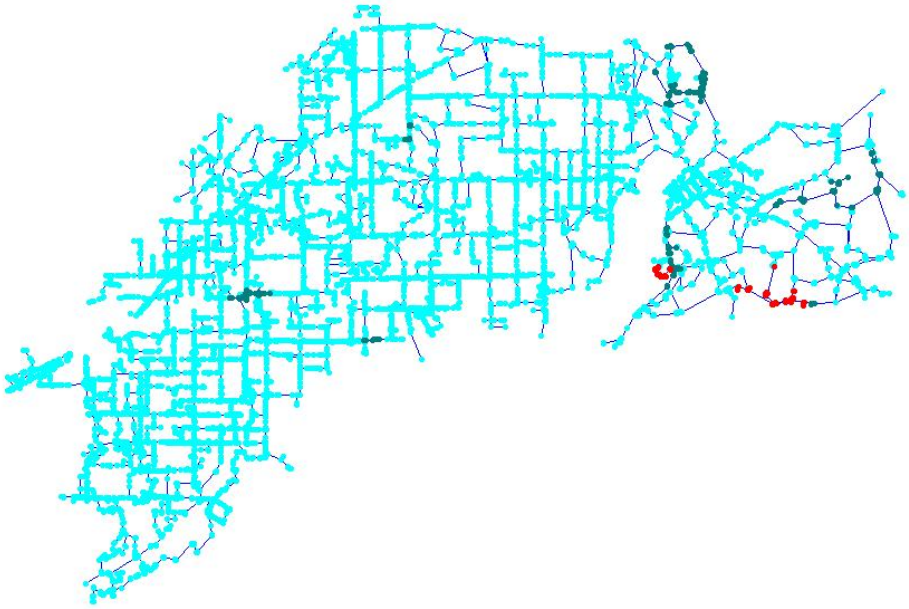

Figure 16: Optimal Locations For 5,000 Kw Generation On SMUD Area B System With Respect To Reducing Peak Load Losses

3.4.2. Optimal Locations for Released Capacity

As a next screen, we tested the three generator sizes for their effects on releasing capacity on the system. This will favor the areas that use a larger proportion of the feeder current carrying capability.

The circuit data supplied by SMUD had two ratings, the smaller of which was interpreted as the normal rating. We found that in many cases this rating was too high to give good resolution on the power being served above this level; not many lines were above this rating. Therefore, we resorted to our default practice of setting the normal rating to 50% of the maximum rating.

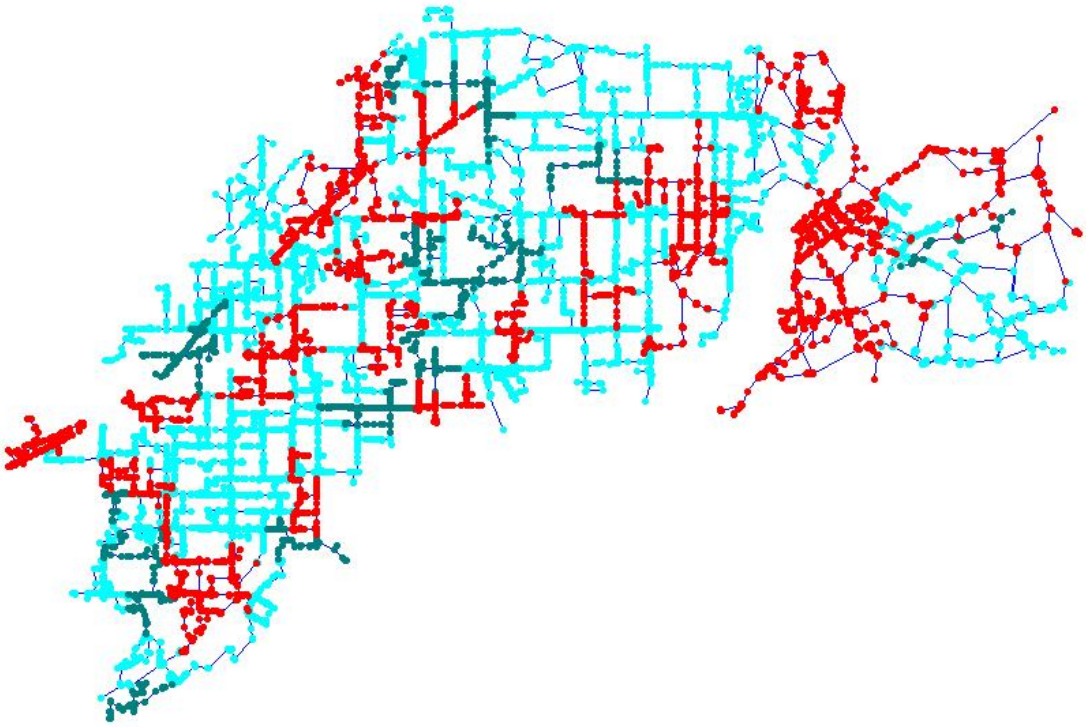

Figure 17: Optimal Locations (Red) For 100 Kw Generation On SMUD Area B System With Respect To Releasing Capacity

Figure 17 shows the results for the 100 kW test generation. Again, the red dots indicate buses in the top 25% of released capacity criteria. For many of these sites, adding a small generator of 100 kW results in 100 kW released capacity. The red circles indicate 75-100 kW released capacity.

Figure 18 is essentially the inverse of Figure 17 with the red areas representing 0 to 25 kW released capacity. These would be the least optimal with respect to released capacity. These areas are typically where the feeders are not loaded the cutoff criteria – 50% of maximum rating in this case – and there is likely little capacity benefit for DG located in these areas.

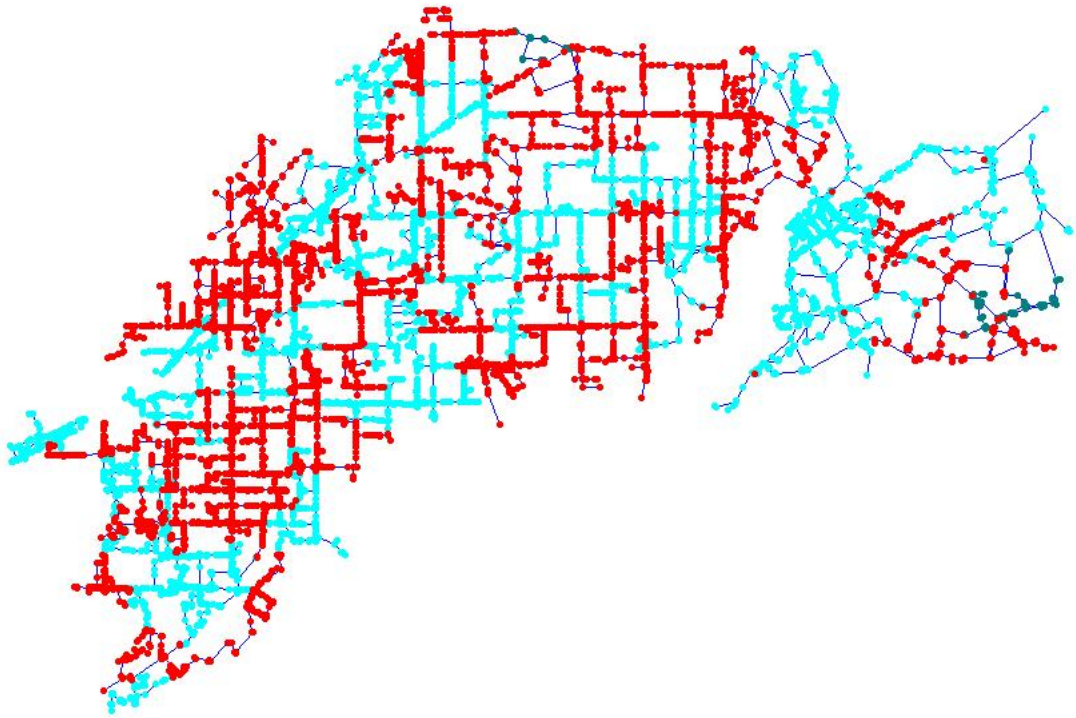

Figure 18: Areas In Red Are Least Optimal For Releasing Capacity With 100 Kw Generators.

As we use larger and larger test generators, the number of buses included in the upper quartile of best locations for releasing capacity shrinks. Figure 19 shows the results the 1,000 kW case. As with the losses, the differences between this and the 100 kW case are minor. The 5 MW test generator case is significantly different. There are only a few locations where the feeder loading is heavy enough to justify this much generation for feeder benefits (there are many locations that can support this much generation, but there may be no feeder benefits). These show up clearly on the plot in Figure 20.

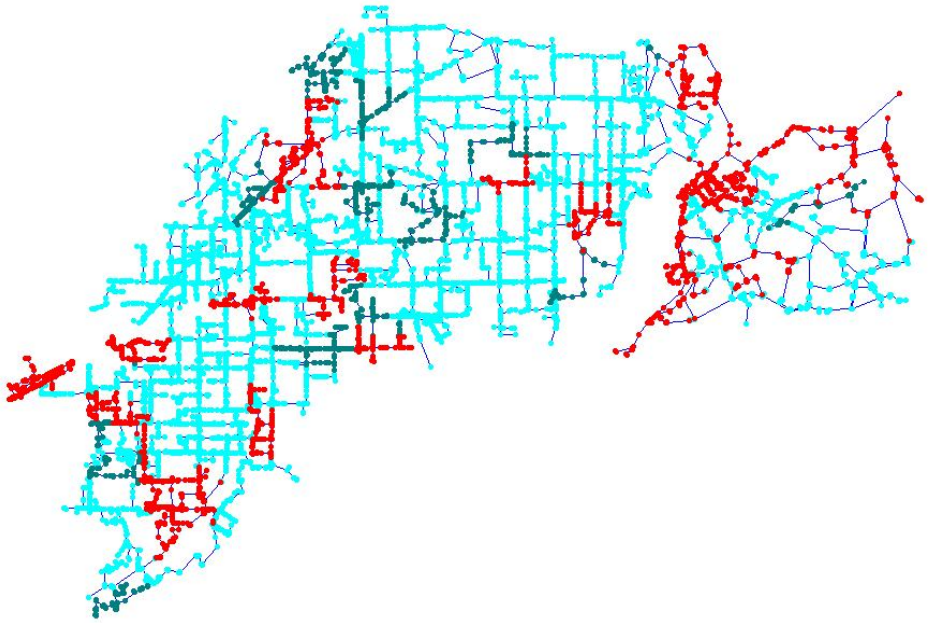

Figure 19: Optimal Locations For 1,000 Kw Generation On SMUD Area B System With Respect To Releasing Capacity.

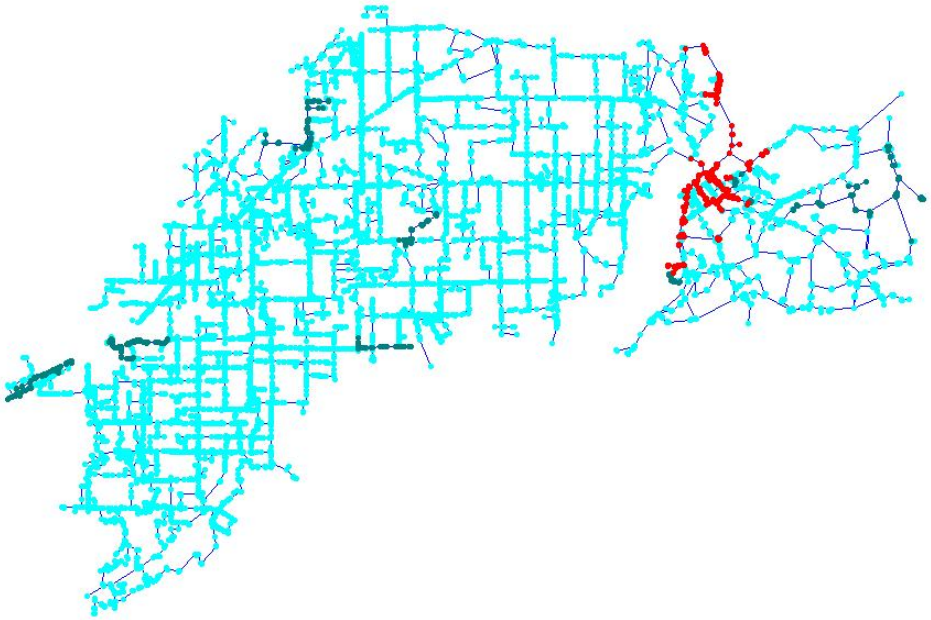

Figure 20: Optimal Locations For 5,000 Kw Generation On SMUD Area B System With Respect To Releasing Capacity

3.4.3. Reference Case 1: Optimally Sited for Loss Reduction

The objective of this analysis is to develop a reference case with generation distributed around the system to achieve the optimal reduction of losses at peak load. Such a case may be used to compare against other proposed DG applications to judge how well the applications do with respect to benefits to the delivery system.

The algorithm for this is straightforward: add generation in small units in sequence, each one at the bus that yields the lowest loss. For 12 kV systems, 500 kW units are generally a good compromise between computational efficiency and a sufficiently small unit size.

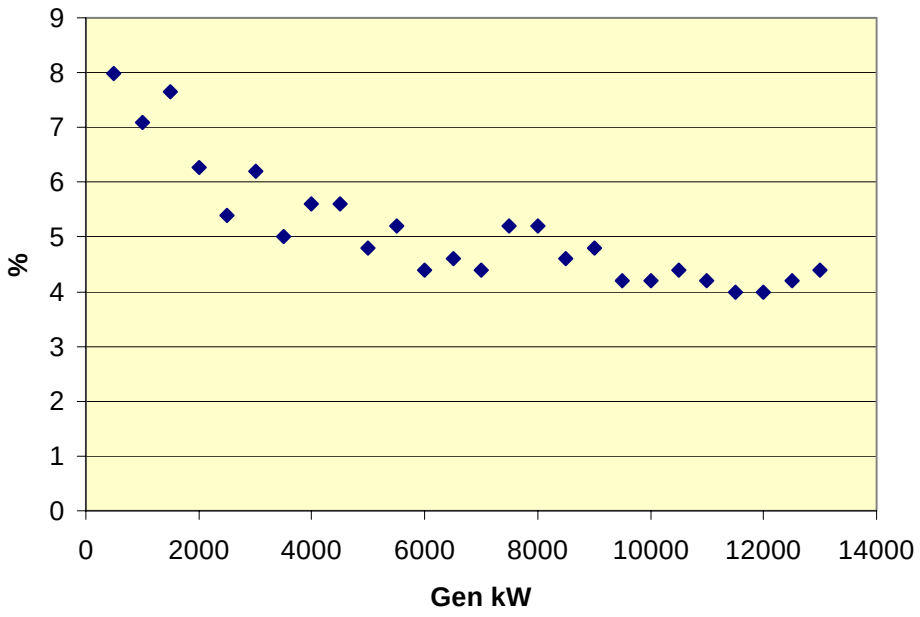

Figure 21: Incremental Loss Reduction In Percent Of Last DG Unit Added.

Figure 21 shows the characteristic of the increment loss reduction for each successive generator addition for the SMUD Area B system. Incremental loss is defined as the loss reduction achieved as a percentage of the DG size. The first unit that is added results in an 8% incremental loss reduction. That is, the losses in the 12 kV system are decreased some 40 kW. Therefore, placing the 500 kW generator in the chosen location reduces the power demand by 540 kW at the peak loading level (the loss reduction is less at lower loading levels).

The incremental loss reduction decreases relatively rapidly with each successive generator addition until it begins to level off at 4-4.5% above 9 MW total generation. There are relatively few locations at which the high incremental loss reduction can be achieved, but

many locations where about half the maximum can be achieved. Eventually, as the area becomes blanketed with DG, the incremental loss reduction declines to about 2%.

Figure 22 shows the result of adding 27 units, or 13.5 MW of generation optimally for loss reduction. Clusters of generation indicate locations that can accommodate substantially more than 500 kW and still satisfy the optimization criteria. Experience has shown that this technique gets very close to, or exceeds, the optimum determined by more mathematically elegant methods.

It is clear from this diagram that the areas of interest with respect to applying DG to improve the efficiency of the distribution system are in the right one-third of the diagram. This is consistent with the locations identified in Figure 13 and Figure 15.

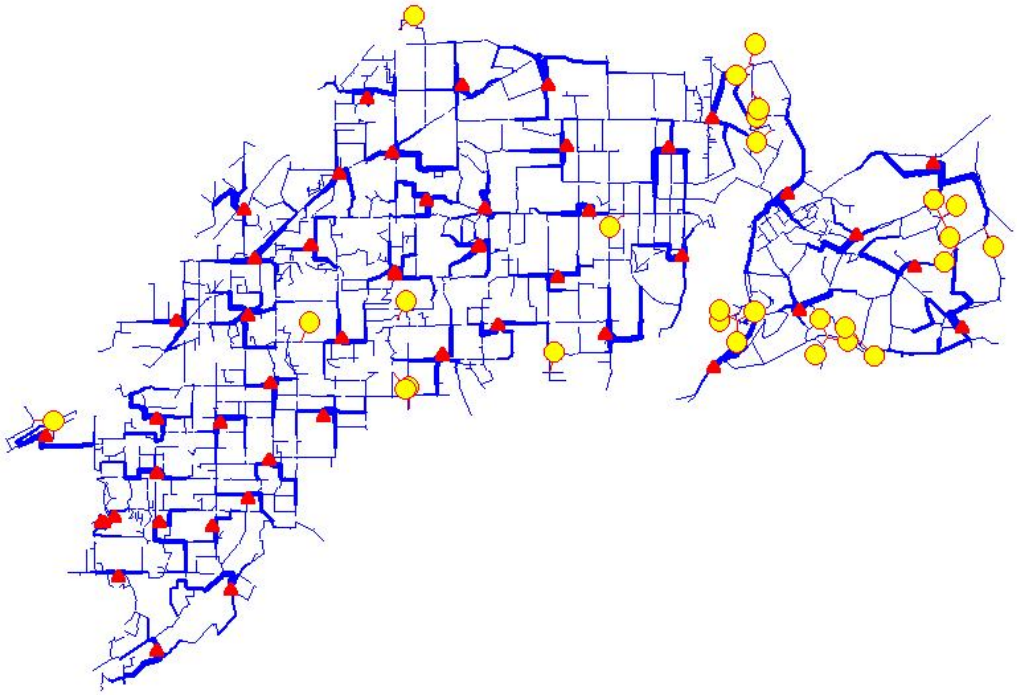

Figure 22: Optimal Siting For 13.5 MW Of 500 Kw Generators For Loss Reduction

The 13.5 MW of generation results in a savings of approximately 670 kW at peak load for an average incremental savings of nearly 5.0%. This establishes a target for what might be achievable for well-placed generation.

3.4.4. Reference Case 2: Optimally Sited for Released Capacity

The second reference case we will establish here will be done in a similar manner as the first, except that the optimization criteria will be mostly released capacity in terms of

reduced EEN at the peak load hour. We will use the same number of 500 kW units as established in the previous reference case, or 27.

Figure 23 shows the results of this optimization run. As with the losses, the first generator is sited at the location resulting in the greatest decrease in EEN. Then the second generator is sited using the same criteria, and so on. Clusters of generators indicate areas that can use more than 500 kW.

The basis for the EEN calculation is the normal current-carrying capacity of the lines, which was established at 50% of the maximum. Thus, this analysis will favor lines loaded more than 50% of maximum and will ignore lines with less loading. By using this rating, there is some correlation to the reliability of the system in the sense that EEN is a measure of how much excess capacity is available to use to backup loads on other feeders in case of faults. Lines loaded less than 50% typically would not need assistance from DG in order to perform the backup function. Therefore, adding DG to those lines would not generally improve reliability. Adding DG to heavily loaded lines would have an impact on reliability.

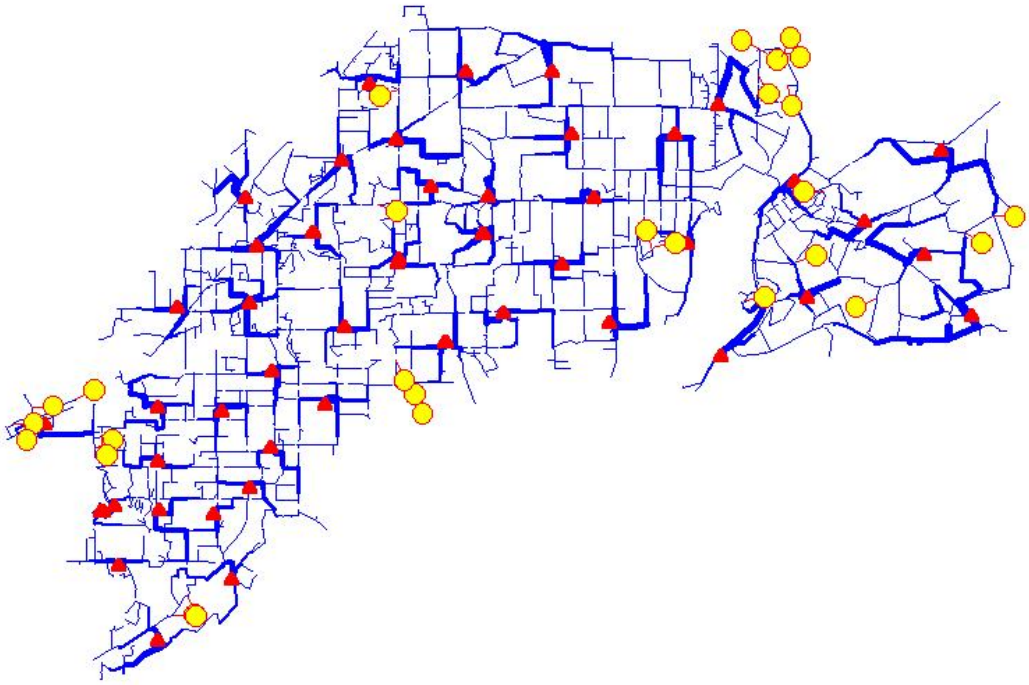

Figure 23: Optimal Siting For 13.5 MW Of 500 Kw Generators For Released Capacity

3.4.5. Reference Case 3: 20 MW Distributed PV Generation

For this reference case, 20 MW of small generation representing solar PV generation was distributed across Area B at approximately 390 buses in proportion to the load. Figure 24 depicts the distribution of the generation. SMUD engineers estimate that there is currently 900 kW of PV generation in Area B. Therefore, this reference case represents a considerably higher penetration level than currently exists.

The generation in this case reduces the losses by 430 kW at peak load for an average incremental improvement of 2.15%. The demand to Area B is reduced by 20.43 MW at peak load assuming the peak generation is coincident with the peak load.

The loss savings is less than half of what is achievable if the generation were purposely sited to reduce losses (compare to Reference Case 1). This is not surprising because by dispersing the generation widely throughout the system, much of it ends up in locations that will yield less incremental improvement.

Impact on the annual reduction in EEN will be evaluated in the Reliability Chapter.

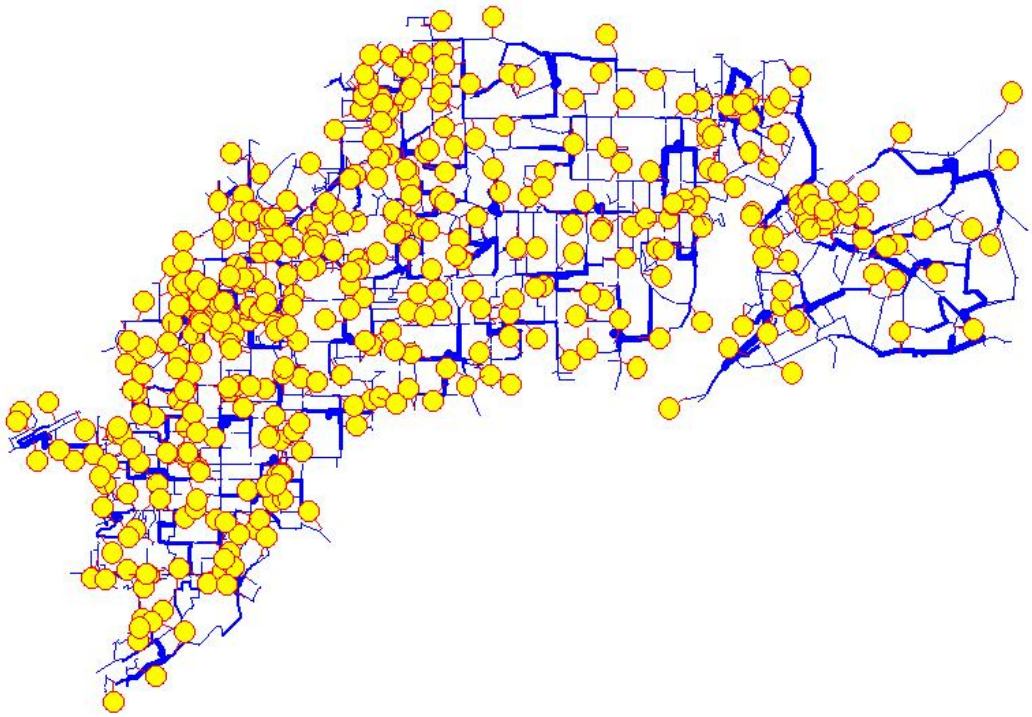

Figure 24: Distribution Of 20 MW Of PV Generation For Reference Case 3

3.5. DG Operational Feasibility

3.5.1. Voltage Regulation Screen

The voltage regulation screen computes the voltage change when the generation is suddenly brought on or off the system. While it may not be likely that widely distributed generation will connect to the system simultaneously, there will be instances when all the generation will suddenly exit the system. The utility distribution fault clearing process is designed for radial systems. Therefore, all DG must disconnect to allow this process to complete successfully. The general rule is for the DG to remain disconnected for five minutes. If the system has become dependent on DG, the voltage could sag too low during this period.

The limit is generally considered to be 5% to prevent power quality problems on the feeders. More than 5% change can be accommodated on some systems if equipped with fast voltage regulators now available from some manufacturers.

The cases tested here did not have enough generation installed to tax the power delivery system with respect to voltage. The generation was sufficiently dispersed to limit the voltage change below that which might occur if the generation were concentrated in one place. The cases where 13.5 MW were added optimally resulted in the voltage change shown in Table 9.

Table 9: Voltage change for 13.5 MW cases

Optimally for losses	2.0%
Optimally for released capacity	2.77%

Based on this screen, the system ought to be able to handle these distributions of 13.5 MW of generation without making any changes with respect to voltage regulation. The system should be able to accommodate at least twice as much similar generation before there might be a likely voltage regulation problem. Even more generation could be accommodated according to this criterion if it is widely dispersed among various feeders.

When the generation is spread out across the system as it might be for 20 MW of solar PV systems (Reference Case 3), the voltage change is computed to be less than 0.2%. At this level, there is not enough generation concentrated on any one feeder to cause much voltage change. Keep in mind that this model does not represent the impact on the 69 kV transmission system, which could register a more significant voltage change for sudden increase of 20 MW in load. Nevertheless, the system should be able to accommodate considerably more such generation assuming it is not concentrated disproportionately to the load.

These are typical results for systems where the feeders are relatively short and the generation is spread out across the system. The more significant voltage regulation problems occur when the generation is concentrated on only a few feeders or on one substation.

3.5.2. Overcurrent Protection Screen

Utility distribution system design is essentially dictated by the method used to detect and clear short circuits. There are two key issues evaluated in this screen that are indicators for DG having an adverse impact on the proper detection and clearing of faults:

1. The amount of increased fault current
2. The percent change in fault current from the original

The first is important for the ratings of the fuses and breakers on the system. These are the devices that must interrupt the fault current that can range from a few hundred amperes to several thousand. The system is generally designed assuming declining fault currents as the distance from the substation increases. Utilities may take advantage of this to use less expensive equipment with lower interrupting ratings at locations farther from the substation. DG can violate the assumption of reducing fault currents. If the fault current increases significantly, fuses or other automatic switchgear may have to be replaced with higher rated equipment in the affected areas.

When the percentage change is high there is increased risk the relays and fuses will no longer coordinate properly. Overcurrent protective devices are coordinated with a certain margin of safety. However, DG contributions to faults can erode this margin in some cases. This is often corrected by simply adjusting a setting on a control, but is an action that must be taken into consideration. In other cases the entire scheme must be changed, requiring the purchase of more capable (and more expensive) relays.

Figure 25: Darker (blue) colors represent areas with larger change in fault currents for 13.5 MW generator case, generators sited for loss reduction.

Figure 25 shows a plot of the system in which the color of the dots representing the buses has been adjusted according to the amount the fault current increased due to the addition of 13.5 MW of generation optimally sited for loss reduction in units of 500 kW as previously described. Synchronous alternators were assumed with a transient reactance of 27% at 600 kVA rating. Figure 26 shows a similar plot for the case where the same amount of generation was added for feeder capacity relief.

The results for each of these two cases are found in Table 10.

Table 10: Fault Current Changes With 13.5 MW DG Case

13.5 MW DG Case	Max Ampere Increase	Max Percentage Change
Sited for loss reduction	500 A	16.5%
Sited for capacity relief	720 A	27.5%

These are relatively minor changes in the fault current, although the latter case might come close to some coordination margins. Normally, one is not greatly concerned with changes less than 50%, although some utilities have coordination margins in the 25% range. As of this writing it is not known if this will impact SMUD's coordination criteria. On short feeders, as we see in this case, problems tend to begin when the generation capacity reaches 30% of design capacity. This would correspond to approximately 2.5 MW on an 8 MW feeder or a total of 6 MW on a 20 MW substation bus.

If there were a problem with this distribution of generation, the areas with the solid dark (blue) colors would likely require some changes in the relaying or the switchgear. For the two cases depicted, the generation is not sufficiently concentrated to significantly change the fault currents seen at these locations.

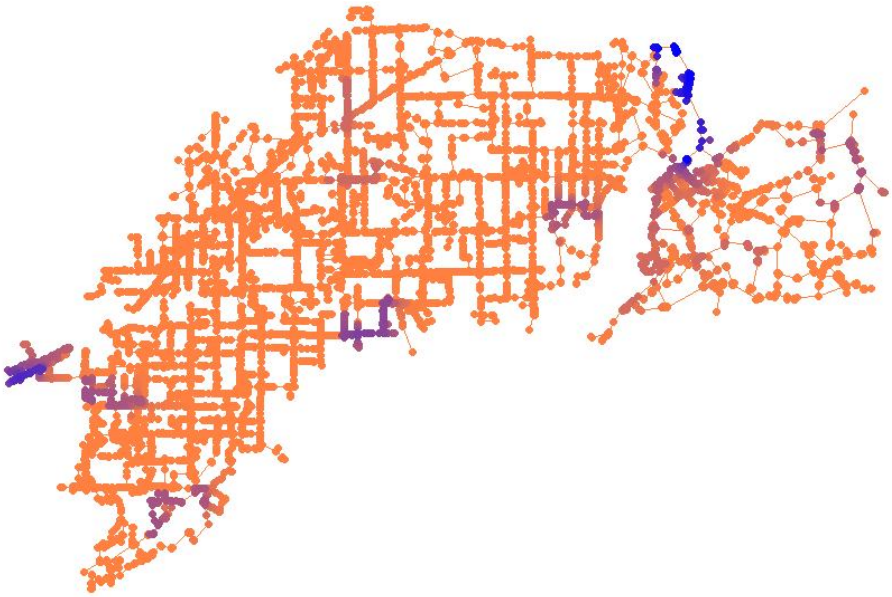

Figure 26: Darker (blue) colors represent areas with larger change in fault currents for 13.5 MW generator case, generators sited for released capacity.

No fault analysis was performed for the PV solar generation. It is assumed this generation will not contribute significantly to faults because the inverters will cease to switch or will limit the current to slightly above normal.

4.0 Load and Resource Analysis

An important element of RDG assessment is evaluation of the fit between load shapes and RDG output. The more coincident the RDG output shape with the load shape, the greater the benefits, particularly in terms of deferring distribution investment. This chapter presents information on the SMUD load shapes and the impact of characteristic RDG output shapes on peak load reduction and losses.

4.1. Local Area Load Shapes

E3 collected 2003 through 2004 load shape information from SMUD Area B for several substations. The substation characteristics were combined into a single load shape that was assumed to apply to the entire area.

Electrotek's load shape analysis tool allows the user to select the year and data subset (system, substation, feeder, or some combination) of interest and view the corresponding load shape. For each hour of each month (e.g. 8:00 – 9:00 a.m., March) the highest hourly system load value determined by the simulations is plotted. The result is an image representing the load shape, as shown in Figure 27.

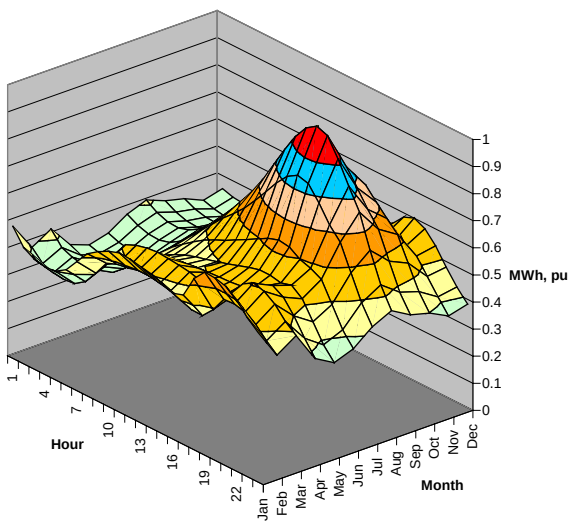

Figure 27: SMUD Area B Annual Energy Load Shape, Normalized

As seen in Figure 27, the SMUD Area B peak energy consumption occurs during mid-day in the summer months expected to have the highest average temperatures. Figure 28 shows a similar plot except the quantity being plotted is the peak load demand in MW. High loads occur over a much broader time frame than the peak energy consumption. This indicates that high load demand days occur commonly throughout the warmer

months from spring through fall, but many more are concentrated during July and August.

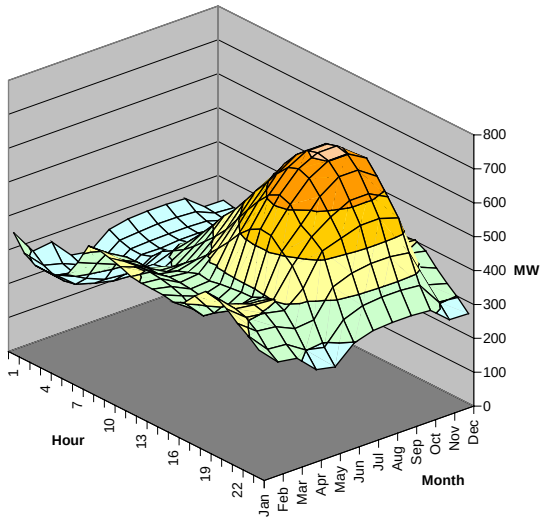

Figure 28: SMUD Area B Peak Demand Shape

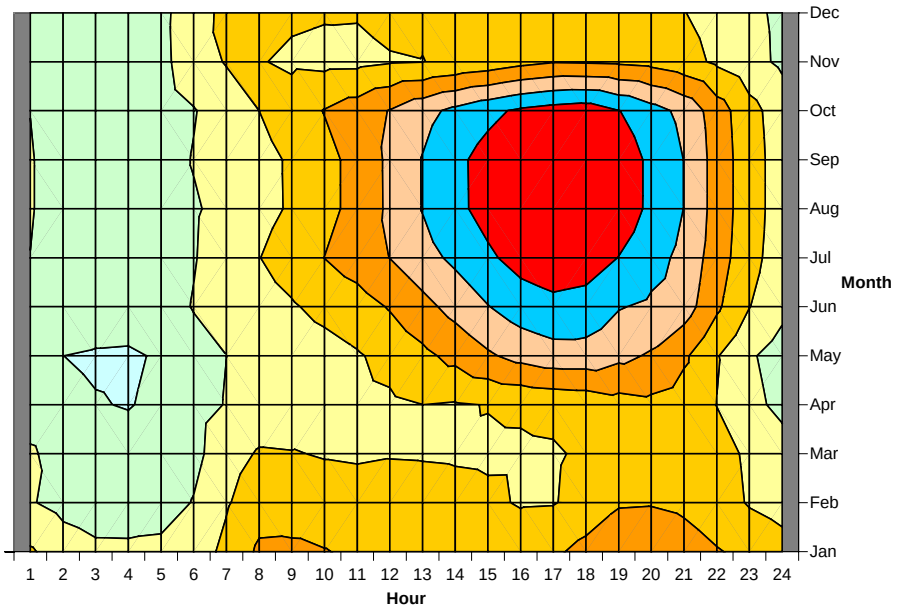

Figure 29: Topographical Representation Of SMUD Area B Peak Load Shape

The data from Figure 27 is shown as a topographical chart in Figure 28 with 70 MW per contour. The topographical chart shows the same information, but is easier to read in terms of the exact peak load timing.

4.2. Renewable DG Output Characteristics

The engineering and economic analyses of renewable generation depend critically on the timing and location of the distributed generation. For each renewable resource, we assume a 'loadshape' of the generator output, and a location for the purposes of the engineering modeling.

Both the output pattern, and the location within the SMUD Area B system change the renewable generator's ability to provide peak load relief (based on coincidence with the system profile above) and reduce losses. The following table summarizes the contribution of each of the characteristic to reduction in EEN, peak, and average system losses

4.3. Summaries of Demands and Savings

There were three primary reference cases with two variations investigated in this analysis. These cases were intended to illustrate what might be possible with various types of generation. Table 11 through Table 13 show the savings in power demand and losses for each of the DG options considered in this analysis. These tables were compiled for the loading level corresponding to a 700 MW peak load. The savings are expressed in both actual energy or power units, and in percentage. If expressed as percent of generation, the values are the savings divided by the amount of energy produced or power capacity of the generation, as appropriate.

Table 11: Purchased Power and Demand Savings

	Gen Size	Purchase Power Savings		Peak Demand Savings	
Case	**MW**	**MWh**	**% of Gen**	**kW**	**% of Generator kW**
Reference Case 1	13.50	118911	100.6	14091	104.4
Reference Case 2	13.50	117913	99.7	13905	103.0
20 MW PV Case	20.00	35164	100.4	9855	49.3
Ref Case 1 Peaker	13.50	5616	103.2	14091	104.4
Ref Case 2 Peaker	13.50	5551	102.0	13905	103.0

Table 12: Annual Loss Savings

	Gen Size	Annual Loss Savings		
Case	**MW**	**kWh**	**%**	**% of gen kWh**
Reference Case 1	13.50	1515188	6.9	1.3
Reference Case 2	13.50	970365	4.4	0.8
20 MW PV Case	20.00	287286.1	1.3	0.8
Ref Case 1 Peaker	13.50	179381	0.8	3.3
Ref Case 2 Peaker	13.50	125246.6	0.6	2.3

Table 13: Loss Savings at Peak Load

	Gen Size	Peak Loss Savings	
Case	**MW**	**kW**	**%**
Reference Case 1	13.50	594	7.1
Reference Case 2	13.50	419	5.0
20 MW PV Case	20.00	162	1.9
Ref Case 1 Peaker	13.50	594	7.1
Ref Case 2 Peaker	13.50	419	5.0

Each of the cases is described in more detail in the following sections. The descriptions will refer back to the tables above.

4.3.1.1. Reference Case 1: 13.5 MW of 500-kW Generators Optimally Sited for Losses

As a reference case to gain understanding of the system and to establish a benchmark for what might be possible with RDG, 27 dispatchable generators, 500 kW each, were sited to reduce peak losses. Another reference case was developed in which the generators were sited to reduce the overloading on the lines (see Reference Case 2). These generation units could represent microturbines or fuel cells operating off some sort of renewable fuel. The resulting locations are shown in Figure 30.

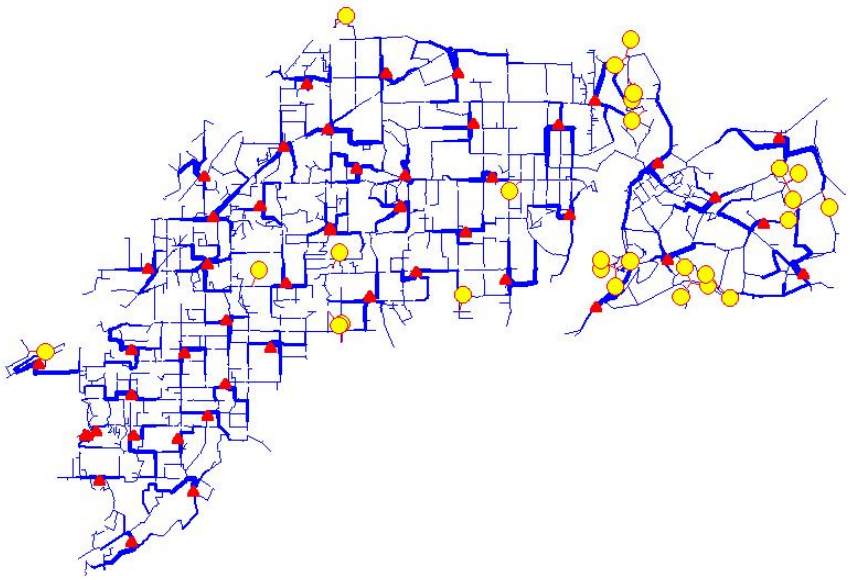

Figure 30: 'Optimal' Locations (yellow circles) Assumed for 13.5 MW of DG for Reference Case 1

This generation was simulated as operating both continuously as it might in a combined heat and power (CHP) application, and as peaking generation at the top 400 demand hours in a year.

If the generation was to run continuously, the total demand is reduced approximately 13.5 MW each hour of the day (see Figure 31). The actual amount varies with time of day. At peak, the demand is reduced more than 13.5 MW because the losses are reduced. At minimum load, the reduction is slightly less than 13.5 MW due to losses in the local lines supplying the generators.

This phenomenon is common with relatively large cogeneration that runs continuously on feeders where the load cycles. At times, the generation produces excess current that actually exceeds the load current and results in losses.

At peak load, the 13.5 MW of generation results in a demand reduction of 14.091 MW, with the additional 591 kW coming from the reduction in losses. At minimum load, the losses increase approximately 50 kW over the base case at the same load. Annually, this generation is quite effective by reducing energy losses in all of Area B by 6.9%.

This moderately good result is expected since the generation was assumed to be sited for optimal loss reduction. However, it does not necessarily imply that it will be economical to run such generators at the off-peak hours just to achieve these loss savings. Even in this favorable case, only 1.3% of the generated energy goes toward loss reduction when considering the entire area. There are pockets where the loss reduction is much greater.

One should keep in mind that the model considers only primary distribution system losses. On the average, primary losses are low in the SMUD system compared to more

heavily loaded systems. The areas chosen for siting generation have moderately high incremental peak loss reduction (7-8%), but most other areas have low incremental loss reduction. There is likely an equal, or greater, amount of losses in the secondary distribution system from the distribution transformer through the service drop cable to the meter. Whether the generators will be connected in such a manner to do anything about secondary losses is an open question. Smaller units connected to existing secondary buses may contribute significantly. Larger units may have separate service drops and will suffer the same secondary loss penalty as the loads.

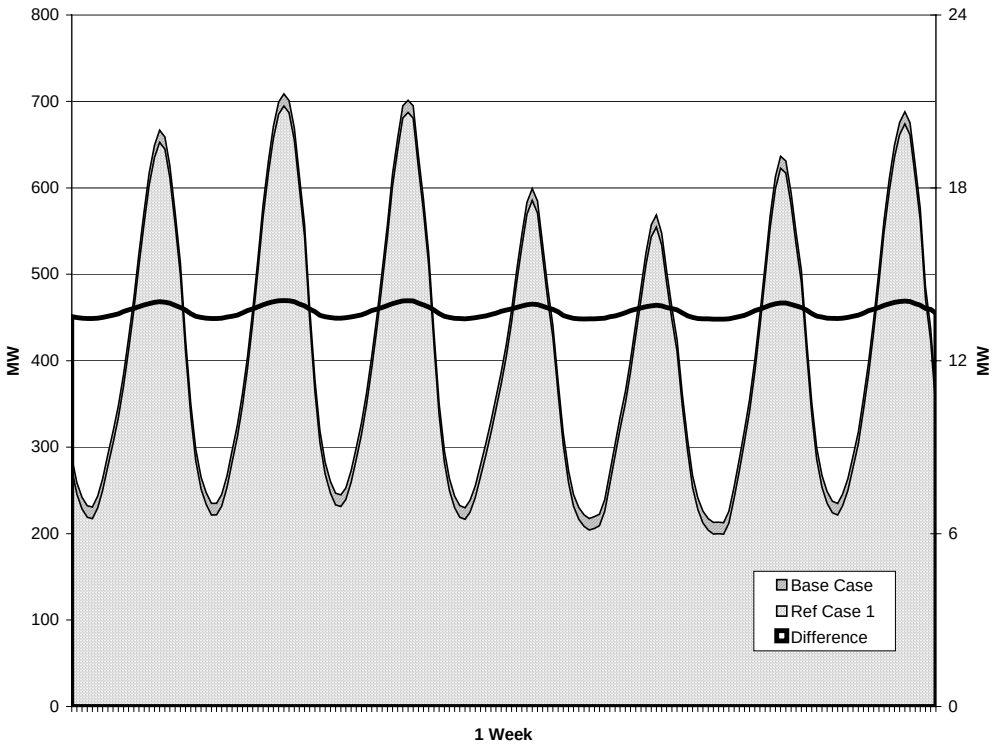

Figure 31: Impact Of 13.5 MW Generation Optimally Sited For Losses, Operated As <u>Baseload</u> Generation For A Typical 7-Day Load Profile During Summer Peak Loading

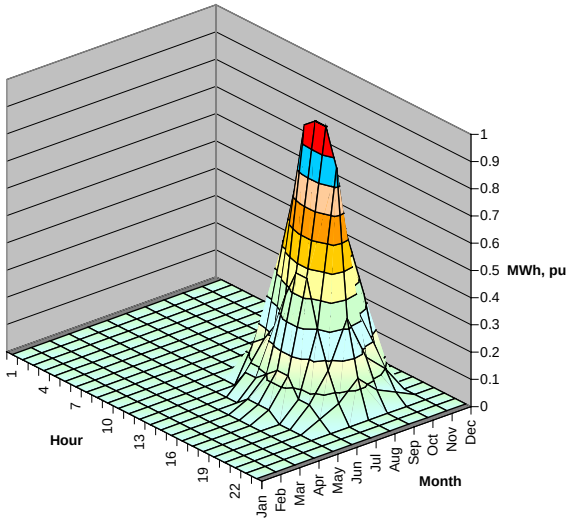

Figure 32: Peaking Generation Dispatch Shape For Top 400 Hours

Running the same generation only on the peak 400 hr of the year (see Figure 32) results in the same peak load loss and demand savings (see Figure 33). The total kWh saved annually is much less than for continuously running generation, but is a higher percentage of the generator output. As peaking generation, a bonus of 3.2% is achieved in demand savings and 3.3% in loss savings. This approaches optimal savings on this system and suggests that there might be economical applications for peaking generation.

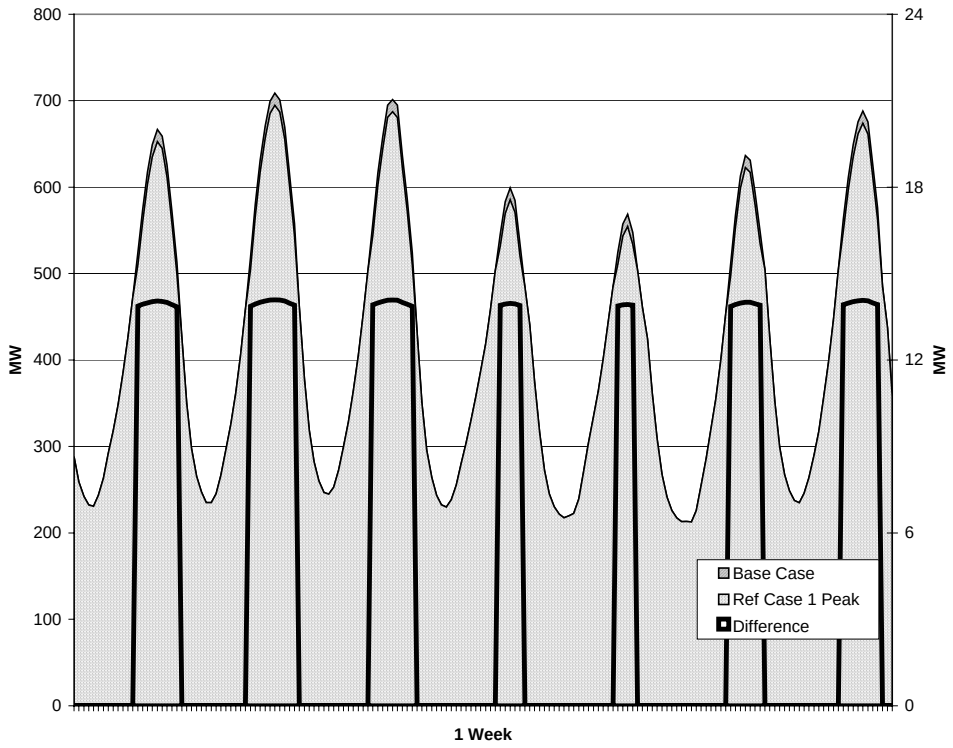

Figure 33: Impact Of 13.5 MW Generation Optimally Sited For Losses

Operated As Peaking Generation For A Typical 7-Day Load Profile During Summer Peak Loading

4.3.1.2. Reference Case 2: 13.5 MW of 500-kW Generators Optimally Sited for Released Capacity

A second reference case was established. As with Reference Case 1, 27 dispatchable generators, 500 kW each, were sited to release capacity in the lines and transformers. These generation units could include microturbines or fuel cells operating off some sort of renewable fuel. The resulting locations are shown in Figure 34.

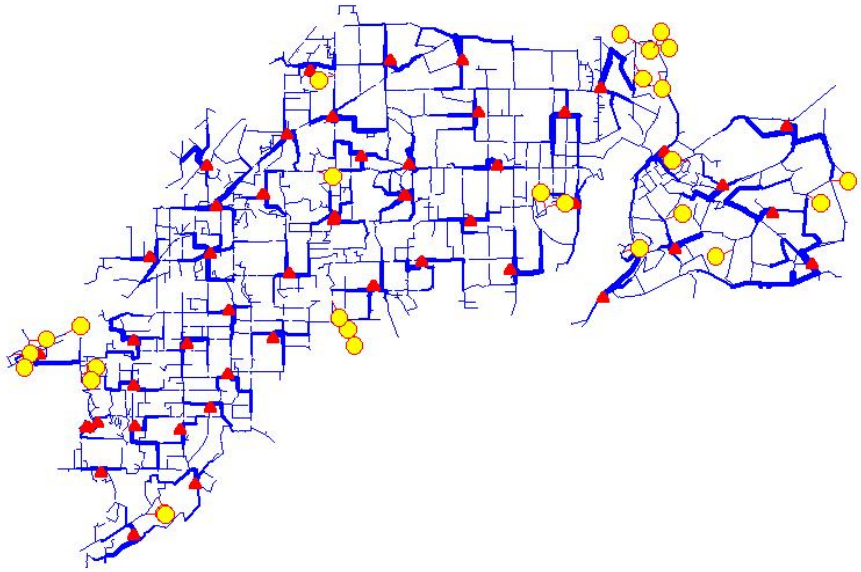

Figure 34: Optimal Siting For 13.5 MW Of 500 Kw Generators For Released Capacity

As in Reference Case 1, this generation was simulated as operating both continuously as it might in a CHP application, and as peaking generation at the top 400 demand hours in a year.

If the generation was to run continuously, the total demand is reduced by approximately 13.5 MW each hour of the day (see Figure 35). The actual amount varies with time of day. At peak, the demand is reduced more than 13.5 MW because the losses are reduced. At minimum load, the reduction is slightly less than 13.5 MW due to losses in the local lines supplying the generators.

This trend is similar to Reference Case 1; however, the results are not quite as satisfactory. The generation locations are good, but not as optimal with respect to loss reduction.

At peak load, the 13.5 MW of generation results in a demand reduction of 13.9 MW, with the additional 400 kW coming from the reduction in losses. At minimum load, the losses increase approximately 120 kW over the base case at the same load. Annually, this generation reduces energy losses by 4.4%.

This result is not quite as good as the generation that was assumed to be sited for optimal loss reduction. Only 0.8% of the generated energy goes toward loss reduction.

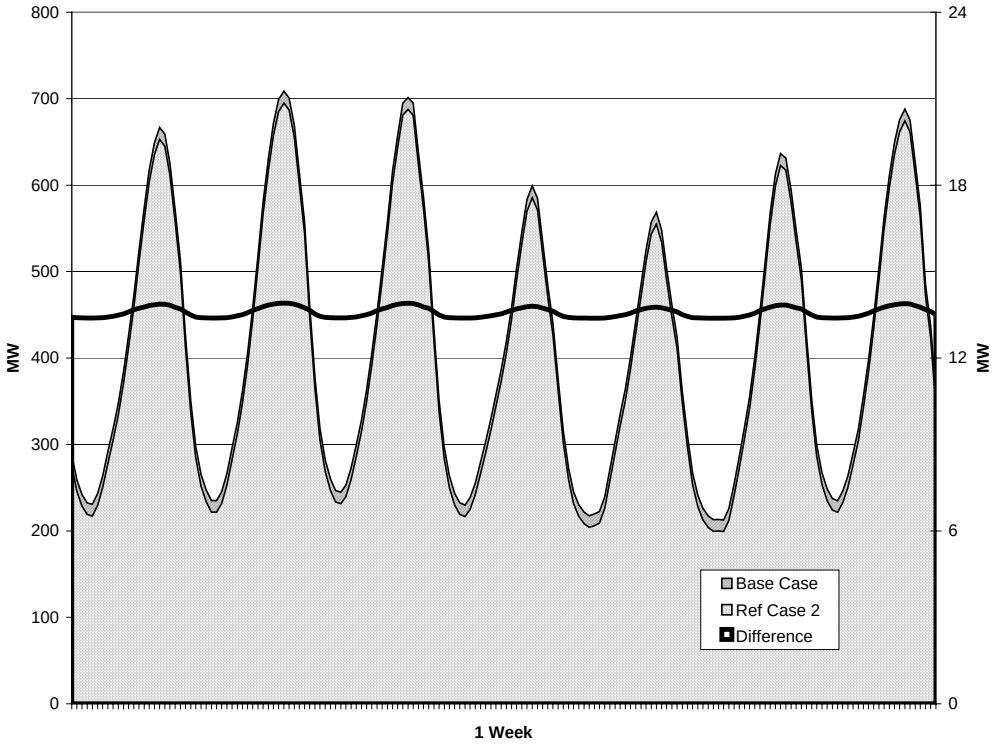

Figure 35: Impact Of 13.5 MW Generation Optimally-Sited For Released Capacity,

Operated as baseload generation for a typical 7-day load profile during summer peak loading.

Figure 36 illustrates the impact of running the generation in this case as peaking generation for only the top 400 hours. The week in which the annual peak occurred is shown. In terms of percent of generation capacity this is much more effective than running the generator constantly. A bonus of 2% is achieved in annual purchased power savings and 2.3% in annual loss savings.

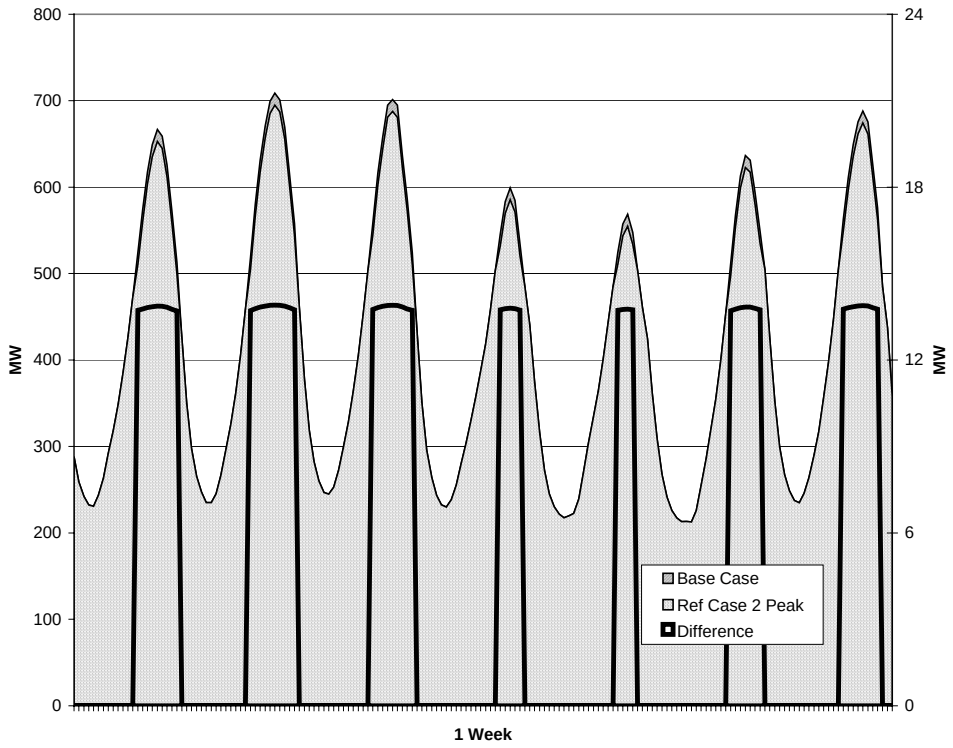

Figure 36: Impact Of 13.5 MW Generation Optimally-Sited For Released Capacity

Operated as peaking generation for a typical 7-day load profile during summer peak loading

4.3.1.3. Reference Case 3: 20 MW PV Generation

For this case it was assumed that 20 MW of photovoltaic (PV) generation is distributed approximately uniformly over the system proportionately to load. Assumed locations are shown in Figure 37. A uniform distribution should yield a good estimate of the maximum capacity and loss reduction benefit possible from this type of generation.

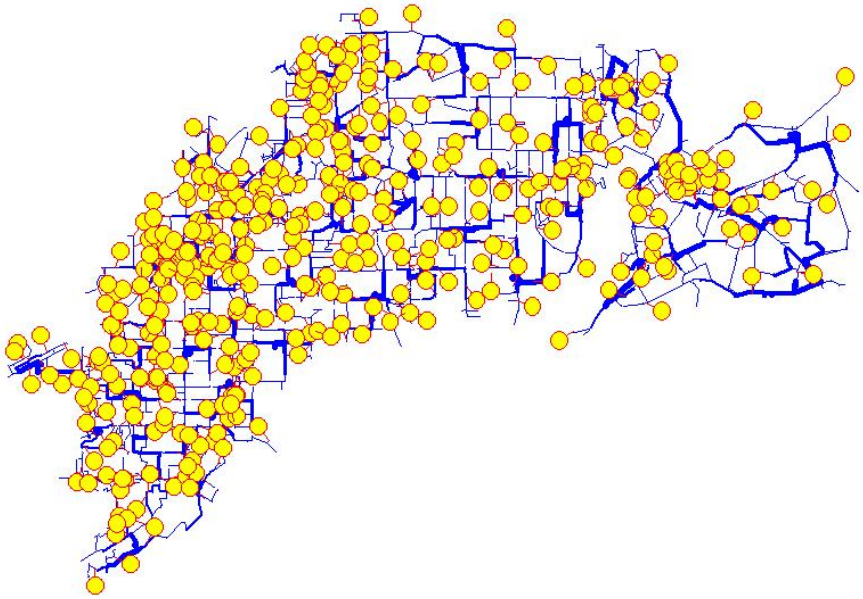

Figure 37: Assumed Locations For 20 MW Of Solar PV Units For Reference Case 3

For the photovoltaic characteristic, metered output from a nearby photovoltaic installation was assumed. The shape for the peak PV output is shown in Figure 38.

Figure 38 shows that PV peak power output is relatively consistent throughout much of the year. It tapers off from the summer peak in the winter months with the January peak output approximately 70% of that in June. The PV output corresponds well with SMUD's overall load shape, suggesting there might be some good value for PV as a deferral mechanism for distribution investment. Figure 39 and Figure 40 further illustrate the degree of coincidence between the load and the solar PV output.

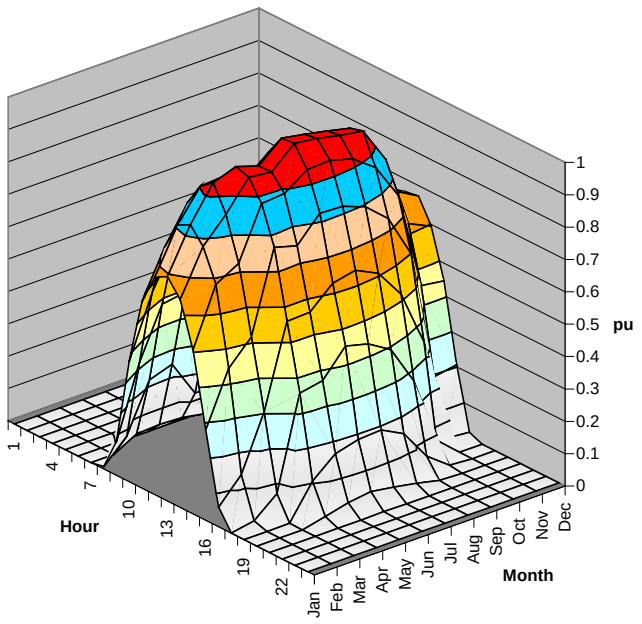

Figure 38: PV Peak Output Shape, Normalized

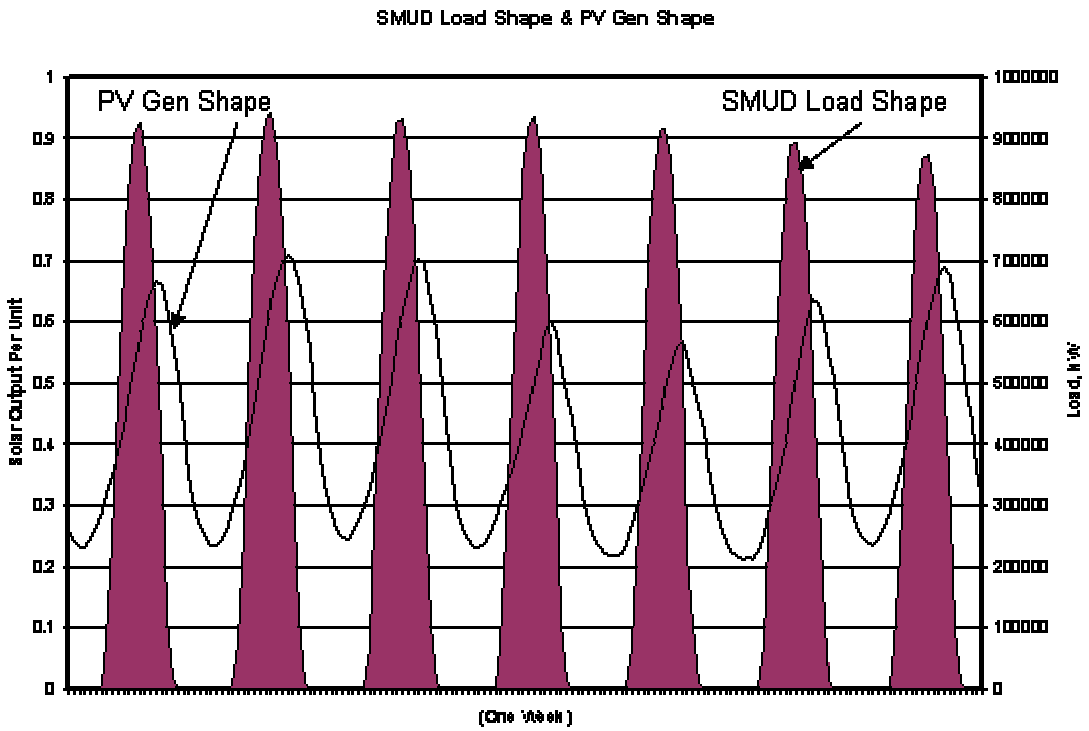

Figure 39: Coincidence Between Solar PV Output And Load During Peak Demand Week

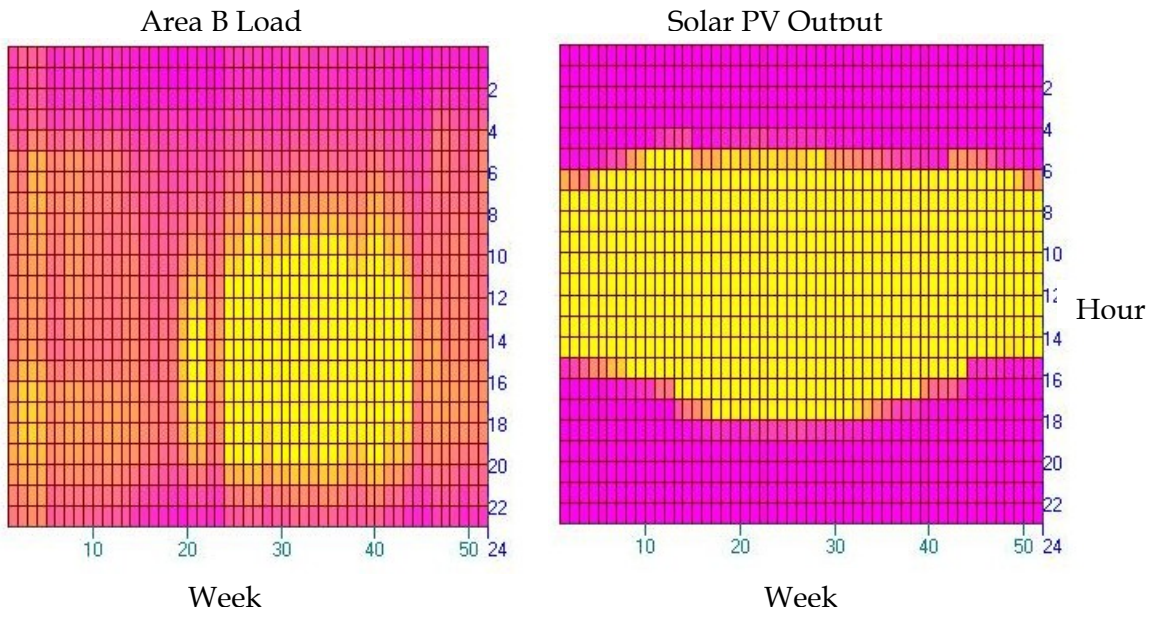

Figure 40. Side-by-Side Comparison of SMUD Area B Load Contour (left) and Solar PV Output Contour

While the correspondence with peak load is good, the duration of the load peak is slightly longer than the solar PV generation can provide without storage. Thus, the capacity provided by PV will be limited, although it is better in this case than for many other utility systems.

The impact on peak demand and losses of the PV system is mixed (refer to Table 11 through Table 13), but relatively good for PV systems. Approximately 1.3% of the energy generated goes toward reducing annual losses. There is nearly a 2% reduction in peak losses (1.9%). The annual savings are only 0.8% of generated energy. The purchased power savings net out to only slightly greater than the net amount of PV generation. The PV output aligns fairly well with the load peak, but misses part of it (see Figure 41). 49.3% of the total capacity goes toward the peak reduction. While this is not as great a reduction as achieved with dispatchable generation, it is good for solar PV generation where a typical value on other systems is in the 30% range.

The loss reduction figures are not as good as in the other two reference cases because the generation is dispersed over areas with low incremental loss improvement factors, as well as those few areas where the incremental loss improvement is fairly high. Thus, the average improvement is much less than the highest areas.

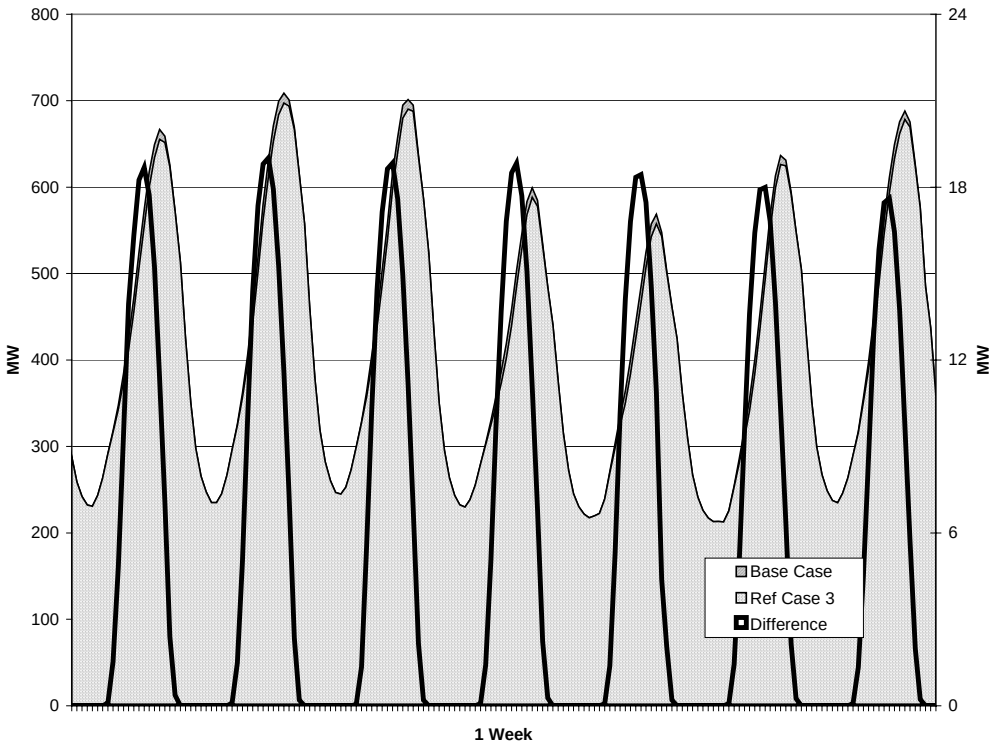

Figure 41: Impact Of 20 MW Of PV Generation Distributed Uniformly

4.3.2. Conclusions

The typical bonus, if any, from RDG that can be expected on this system is in the 1% range. If the generator can produce power through the entire system peak, the peak demand can be reduced by an additional 3-4% over the generator output.

PV generation is more effective against the system peak than in many other power systems. The output catches the maximum peak, but the PV output shape is not broad enough to catch the entire evening peak. Thus, the effective capacity with respect to demand and loss savings is approximately half the rating of the generation.

These findings basically indicate that there are no big surprises expected for the proposed generation. The change in purchased power demand will be very close to the amount generated. If there were very high loading levels on the distribution feeders, there could be more significant gains from well-sited RDG. While some highly constrained systems exhibit gains of 15% or more at peak load when the first increment of RDG is added, the maximum possible in SMUD Area B would appear to be about 7% at peak, with an average 2-3% over the year.

Peaking generation in the proper location should provide some significant additional benefit to the SMUD Area B system. Due to load cycling, continuously running generation tends to give back some of its demand and loss saving benefits during off peak hours.

5.0 Reliability Analysis

This chapter presents the results of an analysis of the impact of distributed generation (DG) on the reliability of the SMUD Area B electrical distribution system. A particular emphasis was given to renewable technologies.

The existing SMUD system has ample capacity for the present peak load of approximately 700 MW. As described by circuit data supplied by SMUD, the system is relatively compact, consisting of many relatively short feeders of one to two miles. Therefore, capacity issues are not as great as they might be in a more heavily loaded distribution system.

Four cases were simulated for this analysis in which the load was increased from 700 MW to nearly 1,100 MW:

1. Base case with no DG modeled
2. 13.5 MW of DG (base load and peaking) sited for optimal loss reduction
3. 13.5 MW of DG (base load and peaking) sited for optimal released capacity
4. 20 MW of widely dispersed solar PV generation

Each of the latter three cases was compared to the base case to determine the incremental capacity improvement achieved. These cases serve as reference cases for what might be achieved in SMUD Area B with appropriate applications of DG.

The system is very clearly summer peaking. Solar PV generation aligns fairly well with the summer peak, achieving an incremental capacity value of 45% of the installed capacity by the measures used here. This is quite good for solar generation.

Well-sited DG generally yields a 3-4% bonus when operating at peak load due to reducing losses as well as supplying some of the load. The first few units sited could achieve incremental loss reduction as high as 7% of the generation capacity at peak load. Of course, operating at lower loading level will yield less improvement and might even increase losses at certain times of the year.

Well-sited dispatchable DG also can yield incremental capacity increases of two to three times the generation output. That is, by addressing the more critical capacity constraints, the overall area load can grow by two to three times the capacity of generation added, while maintaining loss and capacity levels at or below present levels.

Therefore, SMUD Area B should be able to benefit in terms of both loss reduction and released capacity with targeted DG applications.

Only the impact on the distribution system (12 kV) was considered in this analysis. Including elements of the transmission system may alter these conclusions.

5.1. Reliability Evaluation

The reliability impact of small generation on the power delivery system is an area of continuing research. Most distributed generation (DG) proponent literature will claim a

reliability benefit, but there is not agreement over how to define the benefit (see References 1 - 4). The benefit is quite different depending on perspective. Utility engineers are reluctant to provide credit to DG for improving the reliability of the power delivery system. They would argue that benefits of small generation are too small to make a difference in investment decisions and that DG cannot be depended on. Others would argue that a system with more distributed sources is less vulnerable to failures in specific areas.

Utility customers that install DG can experience an improvement in reliability if the DG can supply sufficient power when the utility system suffers an outage. The traditional indices (SAIFI, CAIDI, etc.) for measuring the reliability of utility power delivery systems are too coarse to register a change if a small number of utility customers experience reliability improvement as a result of applying some form of DG. The 'A' in the indices stands for 'average' with the denominator generally being the total number of customers in the system. Thus, an improvement for a handful of customers does not appear significant. Besides, these indices are more dependent on distribution system topology than other factors. The location of switches, fuses, and automatic sectionalizing devices will play a greater role in the isolation of faulted sections and the rapid restoration of power to unaffected areas than nearly anything else.

DG can increase the capacity of the system and there is an intrinsic relationship between capacity and reliability. To evaluate reliability impacts of DG, we compute the additional load serving capacity made possible by the addition of DG. Where the capacity of the power delivery system has been increased, there is the possibility of better accommodating emergency conditions. We evaluate the impact of a proposed DG application on the capacity of a distribution system by developing a 'cost' function proportional to selected operating quantities. In this case, the quantities are the annual energy losses and the energy exceeding engineering limits as the load grows over a planning horizon.

This process gives a better idea of the impact of smaller incremental capacity additions and, therefore, more easily permits comparisons of DG alternatives. In this particular study, we analyzed the main proposed case and compared it to two reference cases that have more predictable characteristics.

5.2. Basic Concept

Figure 42 illustrates the basic concept used in the evaluation of capacity with respect to engineering limits. Two limits are defined: Normal and Emergency (or Maximum). The Emergency limits are never to be exceeded and assume loads would have to be disconnected (load shedding) to avoid damage to the power delivery system. This results in unserved energy (UE). The Normal limit is used for planning studies of the normal circuit configuration, and we call the energy served above this limit EEN, for Energy Exceeding Normal.

The figure illustrates the principle involved using two daily load shapes. One exceeds the Normal limit while the other exceeds the Emergency limit after some assumed growth in

the load or alternate configuration of the system. In general, the normal system configuration is used in studies that evaluate EEN and one or more contingency configurations are used in studies concerned with UE.

The Emergency limit is determined by the maximum amount of current allowed in circuit elements. This limit is more deterministic and is based on physical limitations of the network elements. The Normal limit is more arbitrary and can be set for a variety of planning strategies. In this particular study, only the normal circuit configuration was evaluated with the Normal limit being set to 50% of the Emergency limit. The SMUD feeders and transformers are typically not heavily loaded in the normal configuration and the normal rating was selected so that the capacity gained (or lost) by proposed DG applications could be determined with a reasonable resolution in the EEN calculations. By setting the rating at 50%, one side effect is that no credit is given for having more than 50% available capacity to serve as a backup to other feeders.

This concept is simple when there is but one 'capacity' of a given system. In practice, there are many elements in a distribution system in which limits can be exceeded simultaneously and the evaluation can become quite complicated. The Electrotek Distribution System Simulator™ (DSS) is designed to compute and keep track of the various capacities. For this analysis, EEN and UE numbers are essentially computed feeder-by-feeder and summed for the entire model system at a given hour. This must be done with care to avoid double counting and the program has sophisticated algorithms for doing this. Thus, it is possible to determine the degree to which a plan impacts the whole system under study. While there may be great impact on one feeder, this may or may not result in a significant impact on the whole system.

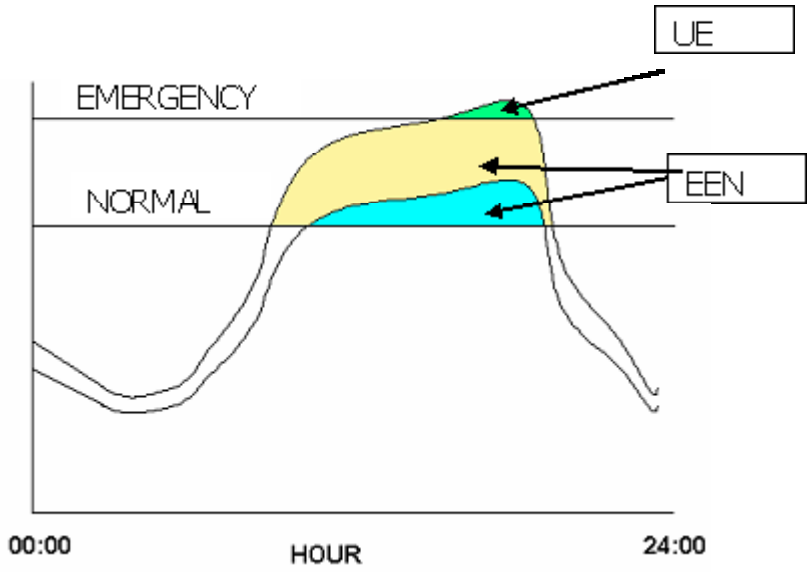

Figure 42: Graphical Explanation Of EEN And UE

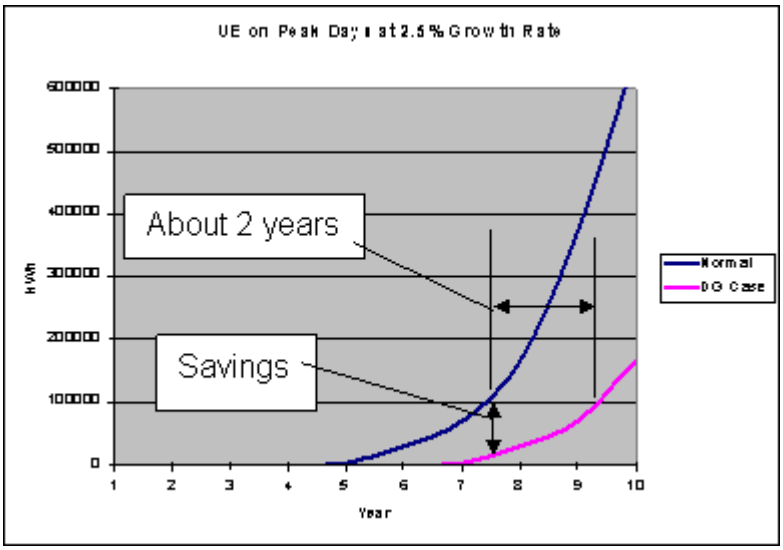

Figure 43: Evaluating The Impact Of DG On The Power Delivery System Capacity

Figure 43 shows the UE curves computed for two cases: the base or 'normal' case, and a case with distributed generation (DG) proposed to extend the life of the system. In this example, the UE is essentially zero until Year 5 at which time the load is projected to exceed the maximum limits for the planning case. Most utilities would plan to upgrade the power delivery system before the system peak load occurs in Year 5, so that the risk of unserved energy is minimized. The question we are attempting to answer in this case is: How long can a proposed DG option defer the needed upgrade?

The vertical difference between the curves represents the savings achieved by the proposed solutions. When the UE numbers can be calibrated to actual system conditions, yielding the Expected Unserved Energy (EUE), this savings can be converted directly to costs, hence the term 'cost" curves. This is done by multiplying the EUE by the value of unserved energy, which is generally in the range of $4 - $10/kWh for typical industrial and commercial loads. When engineering limits are exceeded, the risk of UE is sharply higher and EUE costs become the primary driving factor for new investment in many cases.

These curves are still useful even when the UE or EEN numbers cannot be calibrated to actual system reliability measures. The horizontal difference between the curves reflects the incremental capacity, and, therefore, the timing required for various investments. In the example shown, the projected UE for the DG option increases to the same value as the base case approximately two years later. Therefore, we can conclude that the DG option can be expected to provide the technical capability for two year's deferral of the upgrade as the same risk of UE. If the savings in UE and deferral were economic compared to the

cost of operating the generator, then the DG option would be a good alternative to new feeder and substation construction. This is a very useful analysis for situations described below:

1. The load growth appears that it will outpace new feeder construction and DG is an option for covering contingencies until the construction can catch up.
2. The load growth is slow and uncertain, but pressing the limits of the system, and DG might serve as a hedge against overloads until the growth is more certain and new delivery capacity can be justified.
3. The load is in an area where new lines are expensive or difficult to construct and DG can help serve the load for a number of years, or indefinitely.

Alternatively, MW load can be plotted on the x-axis instead of in terms of years. Then the horizontal difference between the curves represents the incremental load-serving capacity the DG adds to the system. This is becoming a popular measure of the effectiveness of all types if DG and is the method chosen to compare alternatives in this report. In terms specific to this report, given a particular DG proposal, how much more load can be served in SMUD Area B with approximately the same reliability as the present system?

A similar analysis is done for annual system losses. Losses can generally be correlated to capacity measures because they reflect how well structured the system is to serve the load. This often reveals insights not obvious from the unserved energy calculations alone.

5.3. Distribution Reliability

The question of impact of DG on distribution system reliability boils down to: How much more load can be served on the system with x MW of generation?

The answer depends on how 'system' is defined. If we focus on a single feeder, the increase in load served is often closely related to the size of the DG, assuming the DG is an appropriate location to be of assistance. Sometimes, the increase in load-serving capability is greater than the DG size, if it is an appropriate generation technology and in a particularly good location. At other locations, the benefit can be a small fraction of the DG capacity.

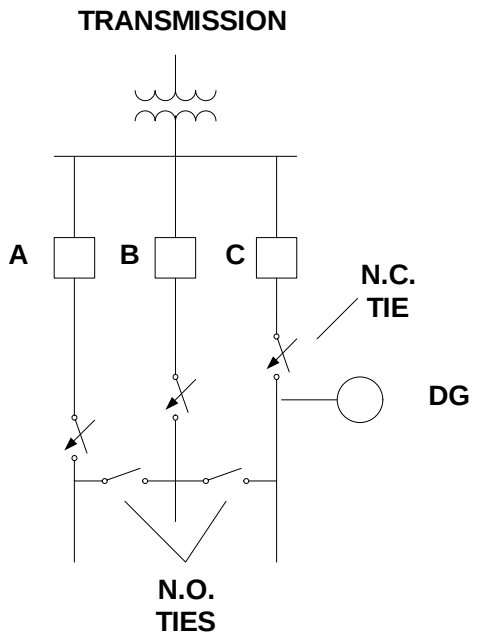

Figure 44: How DG Might Affect Distribution Reliability

If we define the system as consisting of more than one feeder, the net gain is often much less than the DG size even if it is in a good location for one feeder. A specific generator provides capacity to only one of those feeders and to the substation. However, if the DG is sited so that it unloads a feeder, then it is theoretically possible to transfer loads from another feeder if tie switches are placed properly, and achieve an apparent capacity increase. The concept is illustrated in Figure 44. Consider the following cases:

1. If the transmission system goes down, only a small amount of load can be served, i.e., those customers with backup generation (not all DG is capable of providing backup power).

2. If a fault occurs on either Feeder A or B, load can theoretically be shifted to feeder C by opening some normally-closed tie switches and closing some normally-open ties. This feeder is now more capable of serving additional load because part, or all, of its load-serving capacity has been freed up by the DG shown.

3. If a fault occurs on Feeder C, the DG may or may not help, depending on where the fault is located. If the fault is in the section closer to the source, the tie to B can be closed and the DG helps support the remaining load on C while being fed in the opposite direction from B. If the fault is between the DG and the tie, the DG is likely of no assistance.

One way of dealing with the reconfiguration problem is to leave sufficient capacity in the backup feeder to serve the entire load. Thus, any time the load exceeds 50% of the maximum capacity, there is a risk of an outage that cannot be covered by simple

reconfiguration. This is a conservative approach that is found more frequently in urban areas where the feeders are short enough that more easily accomplish that with a single switching operation. It requires more investment in feeders. Some utilities permit the load to grow to 70-80% of maximum capacity. This is a less conservative approach taken when either the utility is willing to undertake more switching options, or is willing to accept more risk of failure occurring at a load level that cannot be completely restored. This might be the case in areas were outage times are historically short. This philosophy generally results in fewer feeders.

For the purposes of this study, the 50% philosophy will be used. That is, any time the loading in the Normal configuration exceeds 50% of the feeder capacity, it will be assumed that the reliability of the system is compromised. The amount of energy served above this level (EEN) will be considered the energy at risk. Not only is the Area B system an urban setting in which this philosophy might well apply, this value also allows for improved resolution in the computing of the EEN values. This provides better comparisons of the alternatives.

5.4. Case Evaluation

For each of the cases described in the following, the total load on the SMUD Area B system is assumed to grow from approximately 700 MW to nearly 1,100 MW.

The simulations are performed for the base case with no DG, two reference cases with optimally sited DG, and one reference case with 20 MW of widely dispersed solar PV generation. The reference cases are designed to have certain expected characteristics. These provide additional insight into the planning problem by showing what might be achievable by nearly ideal applications of DG with respect to selected criteria.

EEN and loss curves are developed for the various options. To compute EEN values for each case, the 'normal' rating of the power delivery elements was set to 50% of the maximum, or emergency, rating as described in the preceding sections. The annual simulation is then performed in the normal circuit configuration and the EEN and losses are tabulated as the simulation progresses. This avoids having to search for critical contingencies and simulate each separately. The reliability evaluation values are computed in one pass. These are then compared to determine the effective additional capacity added by each option compared to the Base Case for the same criteria. The base case energy and peak power load shapes for SMUD's Area B are shown in Figure 45 and Figure 46 respectively.

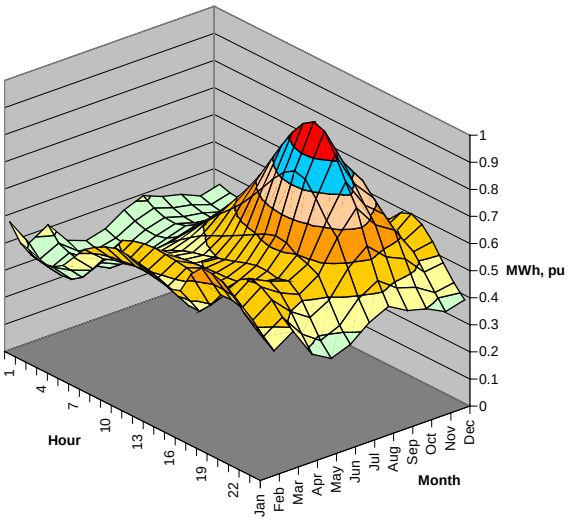

Figure 45: Load Shape (Energy) For SMUD Area B (Normalized)

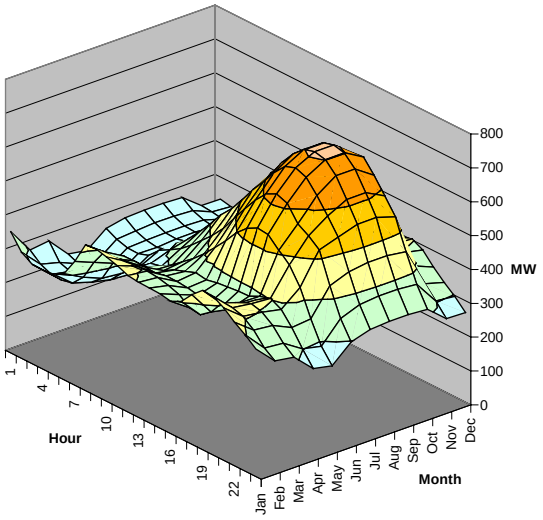

Figure 46: Load Shape (Peak Power) For SMUD Area B

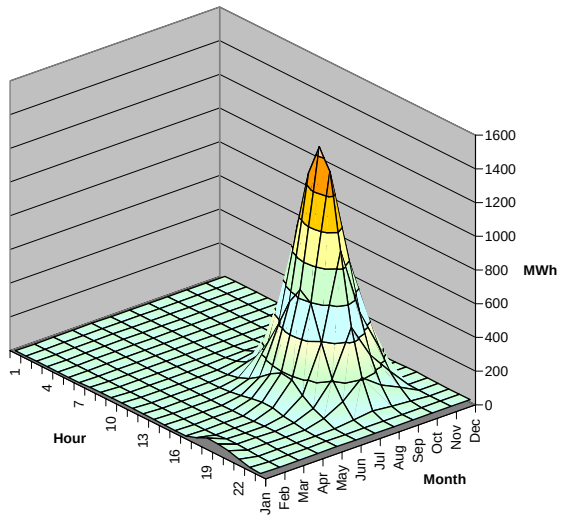

Figure 47: Energy Exceeding Normal (EEN) for Area B

Figure 47 shows the energy delivered through lines when the current exceeds 50% of the maximum rating of the lines. This is referred to as energy exceeding normal, or EEN. Not surprisingly, it shows a very prominent summer peak approximately corresponding to the assumed annual load shape.

DG solutions that would add significant capacity to the power delivery capability of this system would have to deliver power at the times where this characteristic is the greatest. The base case EEN is used as one of the reference criteria for the comparisons described subsequently in this report. The losses are computed simultaneously and both the EEN and the losses are compared to the base case for each of the cases presented in this report.

5.4.1. Reference Case 1: 13.5 MW of 500-kW Generators Optimally Sited for Losses

The reference cases provide a benchmark for comparing proposed DG applications against the base case. Reference Case 1 is designed to be nearly optimal with respect to improving the system with respect to losses using dispatchable generation distributed around the system. To establish this case, 13.5 MW of DG were sited in 500 kW increments to achieve maximum loss improvement at peak load. The details of this case are described in the Engineering Analysis chapter. Figure 48 is a chart from that report showing the distribution of the generators.

The choice of 13.5 MW is simply an arbitrary value selected after the incremental loss improvement had leveled off. That is, the best locations for 500 kW units had been taken and the remaining locations offered nearly the same incremental improvement.

The siting algorithm tends to target areas that are more heavily loaded and areas served by longer lines. It generally results in a DG distribution that has good characteristics for both capacity relief as well as loss reduction, although it would be expected to have better

performance with respect to losses. The areas in which the DG is sited would generally be good areas to target for DG applications.

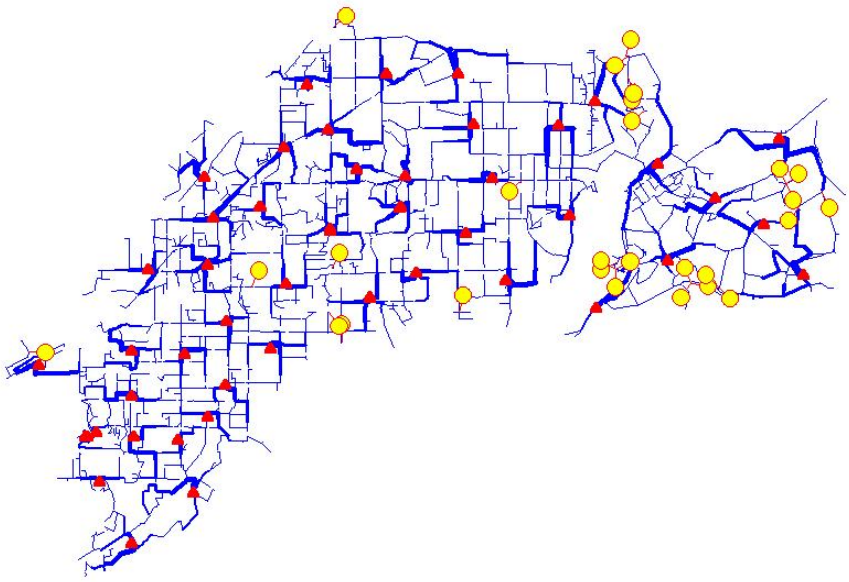

Figure 48: Optimal Siting For 13.5 MW Of 500 Kw Generators For Loss Reduction

It is assumed that the generation is dispatchable. The generation dispatch was simulated in two ways:

1. <u>As baseload generation that runs continuously (or is available to run at all times)</u>
2. <u>As peaking generation restricted to running at certain times.</u> The dispatch characteristic for this generation is shown in Figure 49. This was determined by assuming the generation would be dispatched whenever the load exceeded 500 MW in the base case. This results in approximately 400 hours of operation.

For each of these simulations, as well as the remainder in this report, the load was assumed to grow uniformly from 700 MW to nearly 1,100 MW.

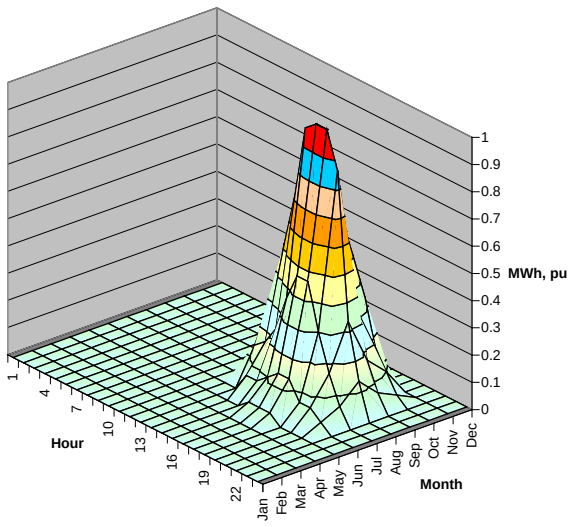

Figure 49: Peaking Generator Dispatch Characteristic

Figure 50 shows the result of the EEN for this case compared to the base case. It shows an incremental capacity of nearly 20 MW growing to 25 MW as the load grows. This simply means that the load in Area B can grow by 20-25 MW before the EEN reaches the same level it would without any DG added. The condition is that the DG would have to be in the locations shown.

The simulation was performed assuming the generation was running continuously. With respect to EEN, this is also equivalent to saying the generation is available to be dispatched at any time with minimal delay to alleviate any overloads. (This does not hold true for the loss comparisons, however.)

Figure 51 shows the same simulation running the generators as peaking generation for only the top 400 hours of the year.

Note that most of the curves show a slight 'hitch' in the characteristic at approximately 1,000 MW. This appears to be due to the computer model modifying the load model to accommodate low voltages. Thus, some additional reinforcement is likely to be needed when the load reaches this level.

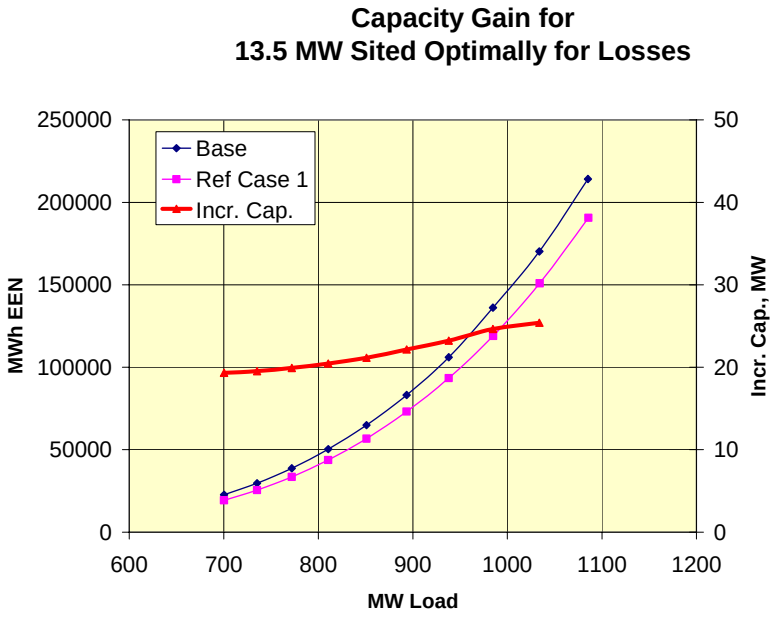

Figure 50: EEN Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Maximum Benefit To Distribution System Losses (Baseload)

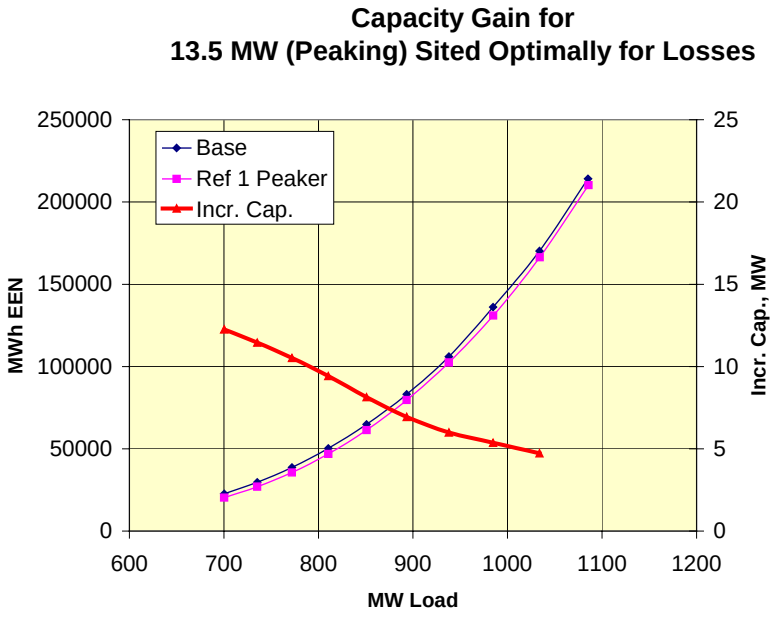

Figure 51: EEN Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Maximum Benefit To Distribution System Losses (Peaking)

In Figure 50 we see the incremental capacity growing as the load grows while Figure 51 shows declining incremental capacity. The difference is that the data in Figure 50 assume the generation is available at any time while the hours for the peaking generation are prescribed. As the load grows, currents exceed the assumed normal limits at hours other than when the generation is operating, implying something should be done to alleviate that situation eventually.

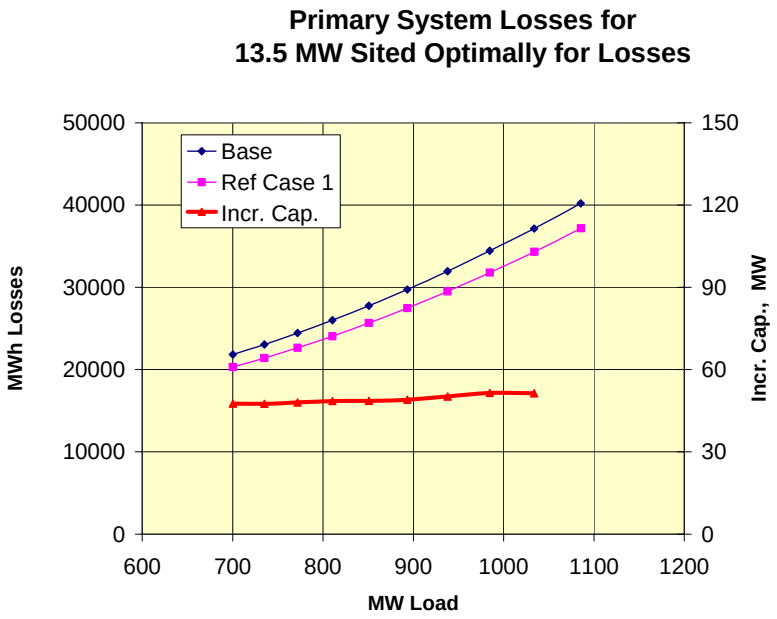

Figure 52: Losses Computed For13.5 MW Of Generation Optimally Sited In 500 Kw Units For Losses (Baseload)

Figure 52 shows the same comparison with respect to the annual losses. This comparison suggests an incremental capacity of more than three times the DG rated output. This is a very good result, not completely unexpected since the DG unit locations have been selected for optimal benefits with respect to loss reduction. It simply means that if the load growth were to occur uniformly across the area, the load could grow by 50 MW before the losses would be the same as without the generation.

This result requires the generation to run continuously. The annual savings are in the neighborhood of 1,500-2,000 MWh. However, in terms of the amount of energy imported into the region, there is little net gain on an annual basis because the generation actually creates additional losses at light load periods when localized line flows reverse. The generation was sited for optimal loss reduction at peak load.

If the generation operates solely as a peaker, a 3-4% boost is achieved through loss reduction each time the generation is dispatched on. In terms of the incremental capacity

as we have be defining it here, operating the generation for the top 400 hours yields a mere 5 MW incremental capacity as shown in Figure 53. Put in other terms, operating the generation in this fashion is equivalent to achieving a 5 MW overall reduction in load for each hour of the year. Obviously, peaking generation is not able to affect losses for the bulk of the hours per year when it is not running.

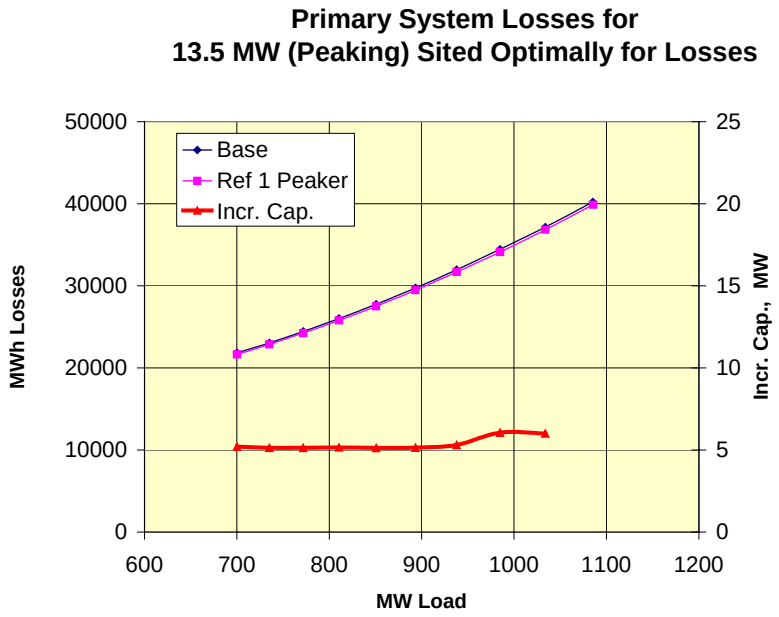

Figure 53: Losses Computed For13.5 MW Of Generation Optimally Sited In 500 Kw Units For Losses (Peaking)

5.4.2. Reference Case 2: 13.5 MW of 500-kW Generators Optimally Sited for Released Capacity

This case is quite similar to Reference Case 1 except that the generators are sited for optimal released capacity (as measured by EEN) instead of losses. Sometimes this optimization is nearly the same as that for losses and this is the case for many of the generators sited by the algorithm. However, there are some key differences in the locations chosen.

The same amount of generation was chosen for this case as for Reference Case 1 simply to provide a consistent comparison. The locations are shown in Figure 54. These are the best locations with respect to reducing the amount of load served in lines with currents exceeding 50% of maximum rating.

As might be expected, this distribution of generation produces a slightly better incremental capacity value with respect to EEN than the previous case. The incremental capacity is in the 27-30 MW range (compare Figure 55 to Figure 50). That is, this generator configuration is equivalent to an overall load reduction of 27-30 MW with respect to

capacity of the lines. By reducing the loading in a few more critical lines, the overall load can grow more than twice the amount of added generation. This is a good result, especially when considering only the distribution system. If we were to include the 69 kV system, the impact could be even greater, although this is speculation at this point.

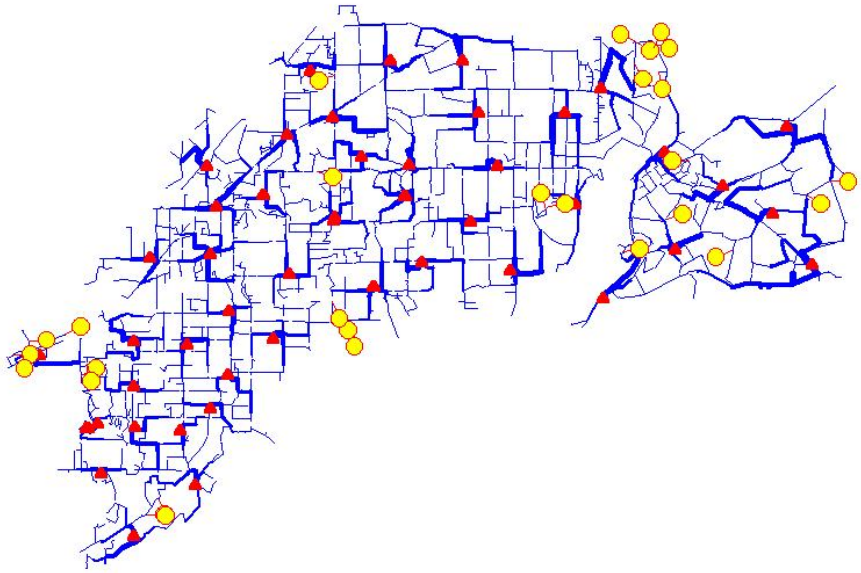

Figure 54: Optimal Siting For 13.5 MW Of 500 Kw Generators For Released Capacity

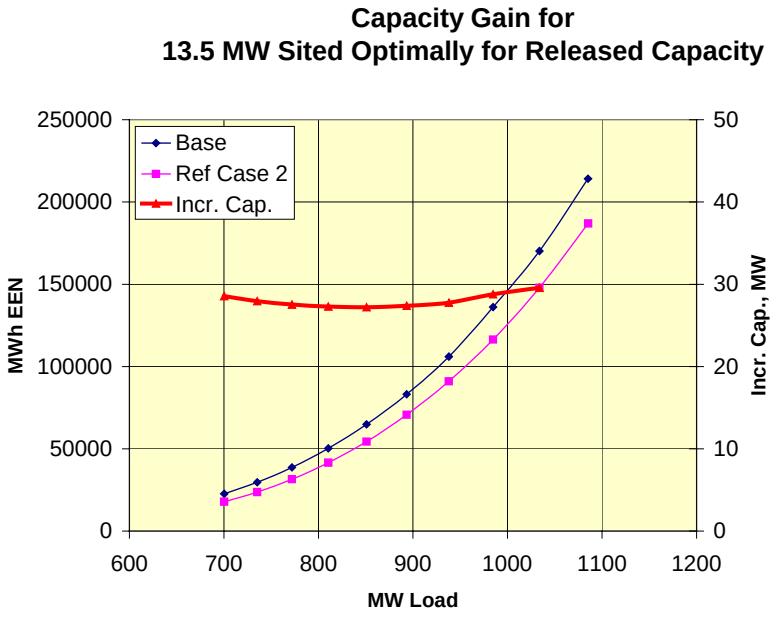

Figure 55: EEN Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Optimal Released Capacity (Baseload)

Figure 55 represents the value achieved for generation that either runs continuously or is available at all times without delay. As before, if the generation is constrained to a few prescribed hours, the increase is not as great (see Figure 56). The EEN measure implies that if the generation is not available at other hours, there is increased risk that a failure cannot be compensated. However, if it is available and the generation is in a particularly good place, there can be a significant bonus with respect to this measure.

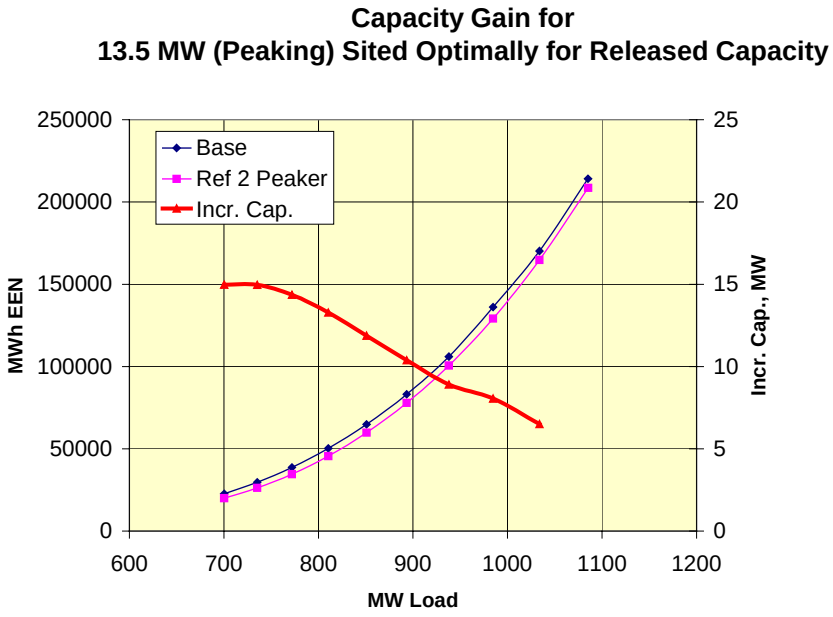

Figure 56: EEN Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Optimal Released Capacity (Peaking)

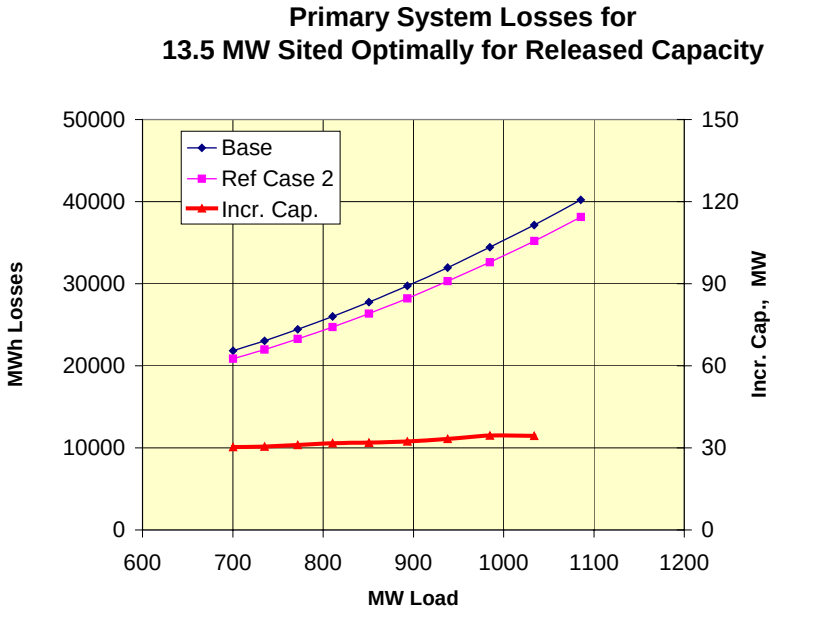

Figure 57: Losses Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Optimal Released Capacity (Baseload)

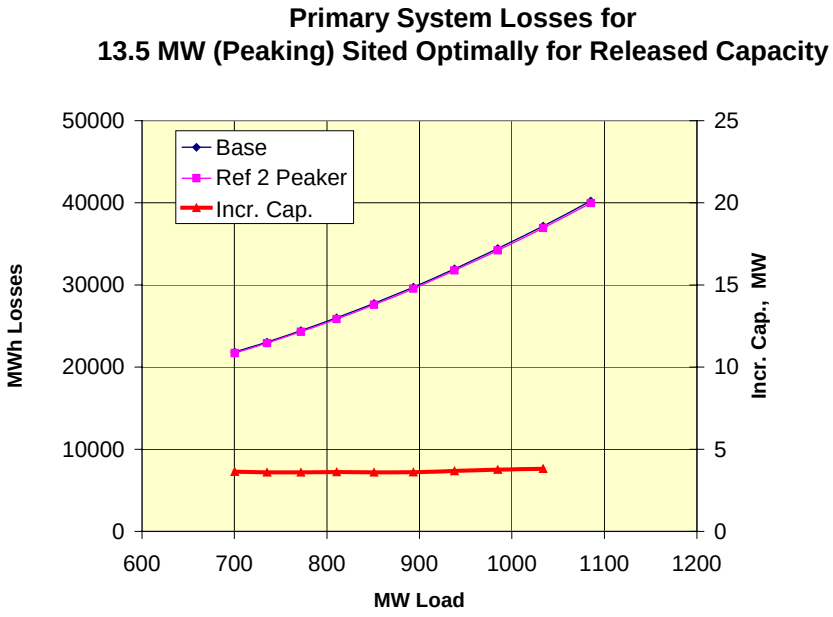

Figure 58: Losses Computed For 13.5 MW Of Generation Sited In 500 Kw Units For Optimal Released Capacity (Peaking)

As might be expected, the measures of incremental capacity are not quite as good as those for Reference Case 1 in which the generation was specifically sited for loss reduction (see Figure 57 and Figure 58). The annual loss reduction if the generation runs continuously is 4.4% instead of 6.9%. However, this is not a bad number. Interestingly, the incremental capacity number of approximately 30 MW for loss reduction is in substantial agreement with that determined by the EEN measure (see Figure 55).

Therefore, both of the reference cases would appear to be good models for DG application to alleviate loss and capacity issues. They give an idea of what might be possible on SMUD Area B if there can be targeted DG applied in this area.

5.4.3. Reference Case 3: 20 MW PV Generation

In this case, 20 MW of solar photovoltaic (PV) generation was dispersed over the system proportional to load. By somewhat uniformly distributing the generation, one might expect to see good uniform capacity relief throughout the system and there would ideally be at least as much capacity gain as the amount of generation applied. Another reason for including this reference case is that PV is a popular form of renewable generation. This case demonstrates some of the issues with this form of generation with respect to system reliability. This case might represent the result of an ambitious, long-term solar power incentive program that achieved the equivalent of 10,000 2-kW residential solar PV units, for example.

The generator locations assumed for the simulation are shown in Figure 59. Figure 60 shows the EEN computed for this case compared to the base case and the corresponding incremental capacity curve. Figure 61 shows the same type of plot comparing the losses against the base case. Both measures of incremental capacity are remarkably similar in this case: approximately 45% of the installed PV capacity.

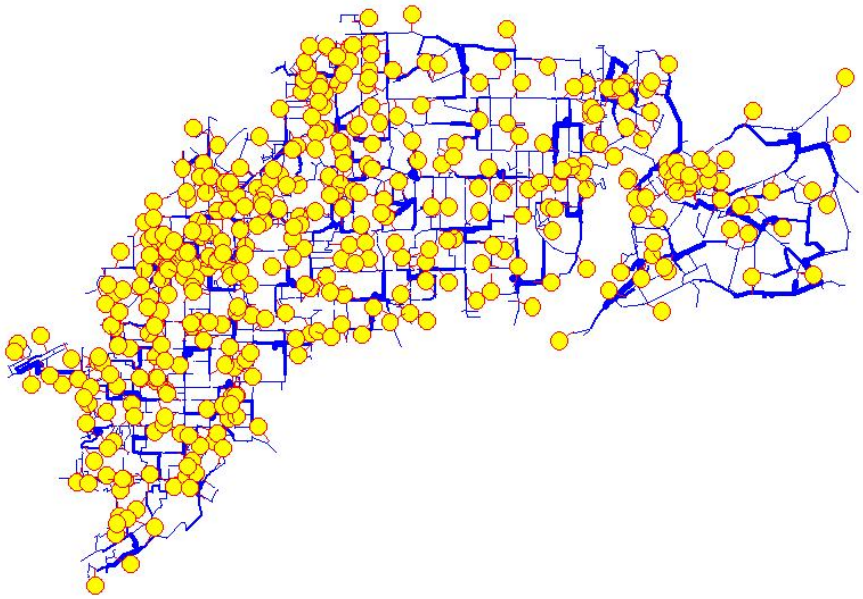

Figure 59: Distribution of 20 MW of PV Generation for Reference case 3

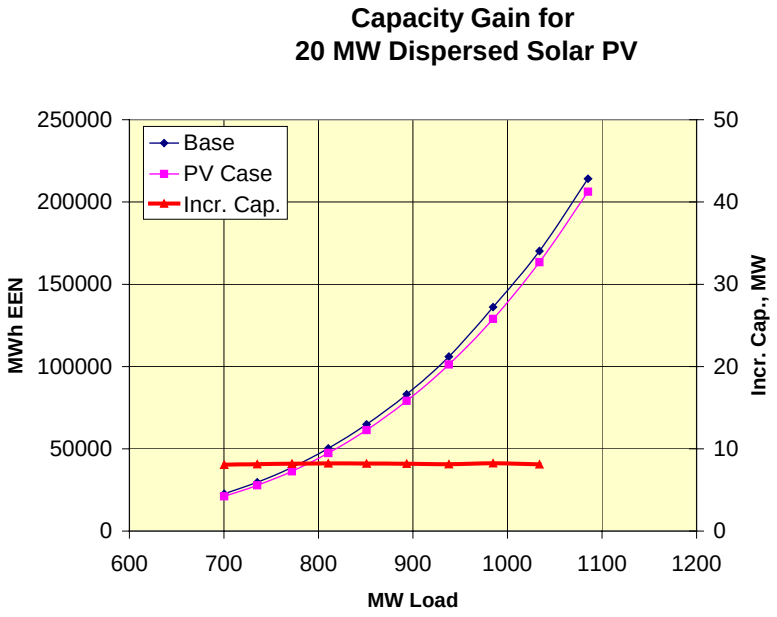

Figure 60: Capacity Gain With Respect To EEN For 20 MW Of Solar Photovoltaic Generation Dispersed Throughout The System

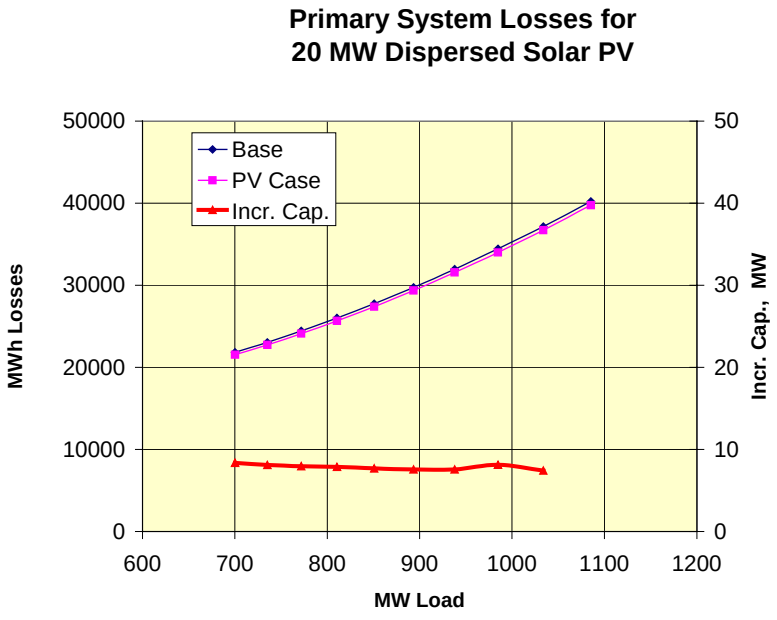

Figure 61: Capacity Increase With Respect To Losses For 20 MW Of Solar Photovoltaic Generation Dispersed Throughout The System

This is a somewhat higher percentage of incremental capacity to installed capacity than we have seen in other cases related to this project. The likely reason is that there is a correspondingly better coincidence between the load shape and the solar PV shape, particularly in the summer months.

Figure 62 depicts the coincidence of the load and solar PV generation assumed for the peak week in the summer. The load shape shown is the computed shape for the entire SMUD Area B system. This coincidence is relatively good, although the load peak is clearly delayed from the generation peak by a few hours. Nevertheless, there is still substantial generation output at the time of the peak. As expected, the solar PV generation is not proportionately as effective as a well-sited dispatchable generator.

The color contour plots in Figure 63 show another way to view the degree to which the solar PV output matches the SMUD Area B load. Here, the yellow color represents the peak load of power output, fading to magenta. Each cell in these plots represents the peak value in a given hour for each week of the year. The solar PV output is quite intense during the middle of the day and tapers off relatively quickly on each side. The peak load demand has reasonably good coincidence with the peak solar PV generation, although the peak load period clearly has a longer duration than the solar PV has the ability to supply power without supplementing with energy storage.

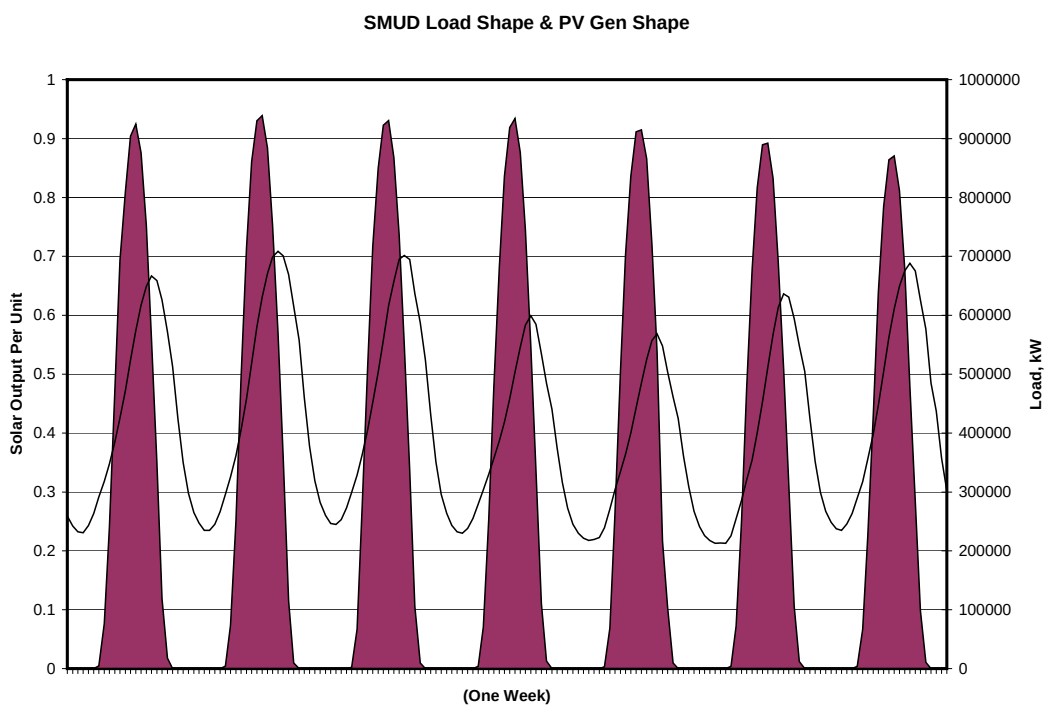

Figure 62: Comparison Of SMUD Load Shape And Assumed Output Of Solar PV Generation For A Typical Summer Week

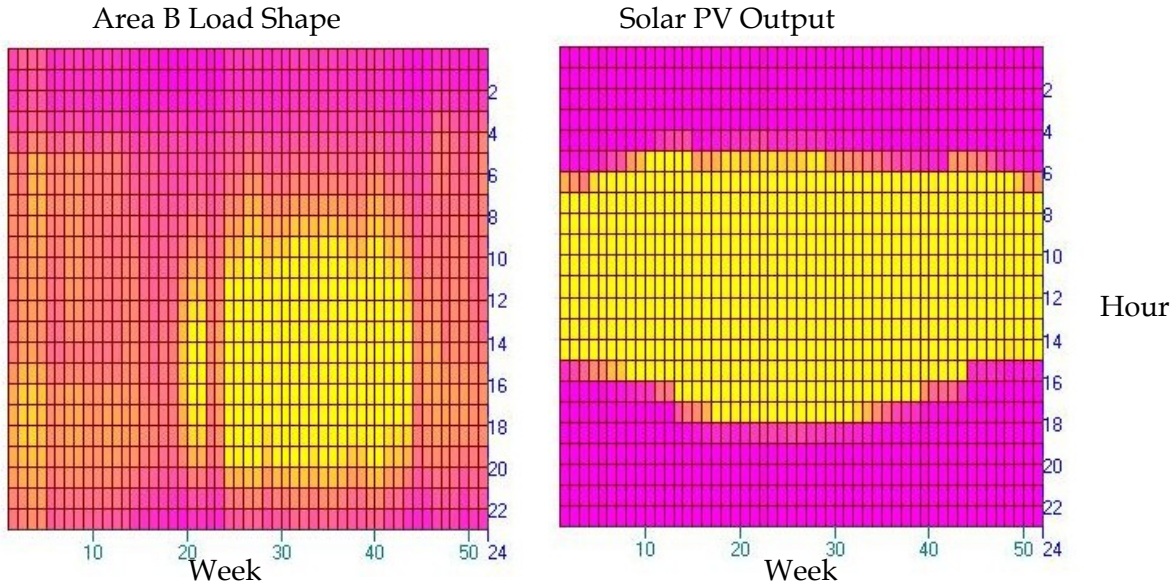

Figure 63. Comparison Of SMUD Annual Load Contour (Left) And Solar PV Annual Output Contour (Right) For Each Week Of The Year

By covering most of the peak load during the summer, the solar PV option earns some credit toward improving the reliability of the distribution system. An effective capacity of nearly 45% of the rating is good for solar PV generation and suggests that the SMUD Area B system might be a desirable match for this kind of generation.

Keep in mind that this hypothetical case assumes a nearly uniform distribution of the generation. If the distribution of PV generation is less ideal, the credit toward reliability could be less if not applied on parts of the system with a compatible load characteristic.

5.5. Economic Reliability Analysis

Here we investigate the economic value RDG impacts on the electric reliability of the SMUD system. Electric reliability is a measure the ability of the electric system to deliver uninterrupted power that is within specified power quality tolerances. Reliability depends upon all systems along the delivery path, but in this study we specifically focus on the impact of RDG on the SMUD distribution system. We do not consider generation or bulk transmission impacts because RDG of the size considered in this study would have little impact on those systems.

The goals of planning T&D systems are to 1) provide grid connection service to all customers, based on the utility's obligation-to-serve mandate; 2) provide electricity within

the power quality standards established by the utility regulators; 3) assure sufficient capacity or load transfer capability to meet peak demand; 4) minimize the extent and duration of outages; and 5) protect public and worker safety.

Of these five goals, RDG can address peak demand (3), power quality (2) and to a lesser degree, the extent and duration of outages (4). In this reliability analysis, we attempt to quantify the ability of RDG to reduce the likelihood and magnitude of load-related thermal overload or voltage sag. These are distinct from outages that customers might experience because of external causes such as vehicle, animal, or tree damage.

Our economic evaluation of the reliability impacts of RDG focuses on the change in unserved energy (UE) and the energy exceeding normal (EEN). UE occurs when loads exceed the emergency ratings of equipment, and are generally evaluated under one or more contingency configurations. UE is measured as the amount of load that would have to be disconnected (shed load) from the system to avoid damage to the power delivery system. EEN is the amount of energy that exceeds the Normal limit. The Normal limit is used for planning studies of the normal circuit configuration, and offers the advantage of not requiring specification of all relevant contingency configurations.

In this economic evaluation, we combine customer value of service (VOS) and deferral benefits with the engineering reliability analysis. There are various methods for performing the economic evaluation, just as there are various metrics for evaluating reliability. This study focuses on the application of EEN to economic valuation, although other metrics are discussed at the end of this section for completeness.

5.5.1. Customer Value of Reliability Improvement

RDG can provide value to utility customers by reducing the likelihood of an outage or substandard power quality. The value of the reliability improvement (VRI) can be calculated directly from the work discussed in the Engineering Analysis chapter, using the following formula:

$$\text{VRI} = \Delta\text{EEN} * p(\text{outage}) * \text{VOS}$$

where:

VRI is the value of the reliability improvement

ΔEEN is the change in energy exceeding normal (as defined in section 5.2) due to the installation of the DG

p(outage) is the probability of having an outage, absent the DG

VOS is the average value of service reliability for customers that would experience the reliability improvement

If the utility planners have identified specific contingency scenarios, VRI associated with each of those scenarios can also be calculated using the following formula:

$$VRIc = \Delta UEc * p(outage_c) * VOS$$

where:

Subscript c corresponds to the specific contingency scenario

ΔUE is the change in unserved energy for that contingency scenario

Contingency scenarios were not simulated for SMUD.

Unlike other cost elements considered in this study, there is no market for VRI . The value to customers is an 'indirect' or non-transactional benefit akin to the environmental benefits from reduced air emissions. The VOS reliability represents the maximum amount a customer would be willing to pay for their electric service. It is difficult to judge customer willingness to pay, however, so the value is often approximated by the opportunity cost of electric power, which equals the value of unsupplied electricity. VOS reliability therefore becomes synonymous with customer outage costs.

Costs of interruption vary by customer class. Outage costs to commercial and industrial customers include lost sales, reduced manufacturing output, spoiled inventory, damaged equipment, extra maintenance, and overtime. Costs imposed to residential customers include spoiled frozen foods, substitute heating and lighting costs, and inconvenience. Some customers have a high per-outage cost, where even a brief interruption causes large problems, such as a semiconductor fabrication plant or a stockbroker, while others may have few problems until the outage lasts long enough, such as at an ice cream factory or plastic molder.

Reported outage costs vary tremendously. One common approach is to normalize outage cost on a per kWh basis of energy not supplied. A range of values from the literature is illustrated in Figure 64 for several residential, commercial, industrial, and combined commercial and industrial surveys. Estimates typically range by an order of magnitude. Much of the variation is due to differences in the attributes of the outages that the studies are evaluating, as well as the methods that the various studies have employed.

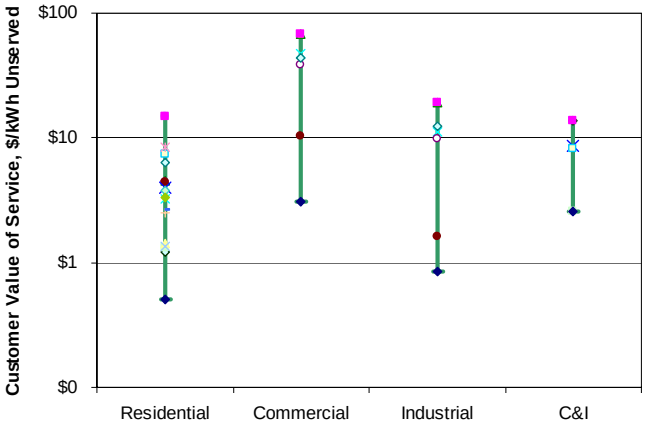

Figure 64: Typical Range Of Reported Values For Customer Value Of Service (VOS)

The range is due to survey methods used, the types of outages considered, and the specific residents or industries involved. Moreover, customer valuation of outage costs can vary depending upon customers' experience with outages, and depending upon whether the survey aims to determine their 'willingness to pay' or their 'willingness to accept.' As 'willingness to accept' asks how much the customer should be compensated for lower reliability, the customers provide values here that are always significantly higher than their response to the willingness to pay question. The analyst should take care to assure that VOS values are for willingness to pay and to the extent possible, reflect the attributes of the outages that would likely be avoided by the RDG installation.

Typical mid-range VOS values are listed in Table 14.

Table 14: Mid-Range Customer Value Of Service (VOS) Estimates

Customer Class	$ per 1 hour	$ per 4 hour	$ per kWh
Residential(1)	$4-5	$15-20	$4-5
Commercial(2)	$400-600	$1,000	$30-50
Industrial	$10,000-20,000	$40,000-50,000	$10-20
Agricultural	$100 (summer)	$400 (summer) $2,500 (winter)	$5-10

(1) Home office customers have not been specifically surveyed. The magnitude of this market is uncertain but growing, and has VOS much higher than a typical residence.

(2) The fast-growing "data center" sector has not been specifically surveyed, but may account for a significant fraction of new growth and have demonstrated much higher value of service than the average commercial business.

For the purposes of this study we used $4/kWh for residential customers, $30/kWh for commercial customers, and $10/kWh for industrial customers.

VRI results for SMUD are shown in Table 15 below. The table shows the impact of an equipment failure that occurs randomly within the year and lasts for 24 hours. The ΔEEN column shows the reduction in annual EEN as a result of the RDG installation. Given the EEN under the 'no DG' case, this one day out of 365 translates to less than one outage hour per year . The probability of an outage (p(outage)) and the VOS value of $8/kWh are representative of a mixed use area with residential, commercial, and light industrial customers in California.

Table 15: Value of Reliability Improvement (Year 2004)

Case	EEN (kWh/yr)	ΔEEN (kWh/yr)	*p* (outage)	VOS ($/kWh)	VRI ($/yr)
Base (no DG)	22672599	N/A	0.002%	8	0
Reference Case 1	19272934	3399664	0.002%	8	$ 544
Reference Case 2	17837990	4834609	0.002%	8	$ 774
20 MW PV Case	21142453	1530146	0.002%	8	$ 245
Ref Case 1 Peaker	20354479	2318120	0.002%	8	$ 371
Ref Case 2 Peaker	19980569	2692030	0.002%	8	$ 431

Total usage is 2,716 million kWh per year, so the annual EEN in the 'no DG' case represents less than 1% of the total annual usage, a small risk of outages related to loading levels.

5.5.1.1. VRI Benefit Feedback Loop

The VRI benefit described above may be factored into the benefit/cost analysis of each DG option. We allow this to occur through a 'switch' in the 'feedback' tab of our screening model. If set to 'true' the VRI values are factored into the benefit/cost analysis; if set to 'false' they are not. This feedback loop is represented by the dashed line in Figure 65.

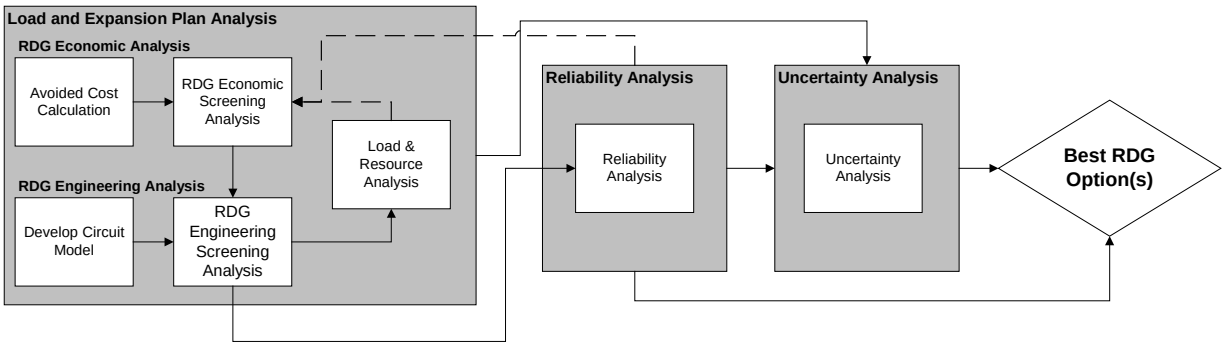

Figure 65: RDG Assessment Analysis Process Flow Diagram

5.5.2. Deferral Benefit of DG

Using this approach, we are able to determine how many years of distribution investment can be deferred without EEN exceeding a pre-determined level. The pre-determined level is typically the EEN level that would have existed at the time the original distribution upgrade would have been installed. This is considered to be the level of reliability that would be acceptable to the utility before an upgrade is required. The deferral benefit is the financing cost savings attained from delaying the construction. As long as the inflationary increase in costs to build the project at a later date is lower than the utility's weighted average cost of capital, deferral offers net positive benefits.

Figure 3 shows how deferral length can be derived from the SMUD EEN curves. Assume that a level of 30,000 MWh of EEN was determined to be the acceptable level, and the utility would invest in new distribution if EEN was expected to exceed this level.

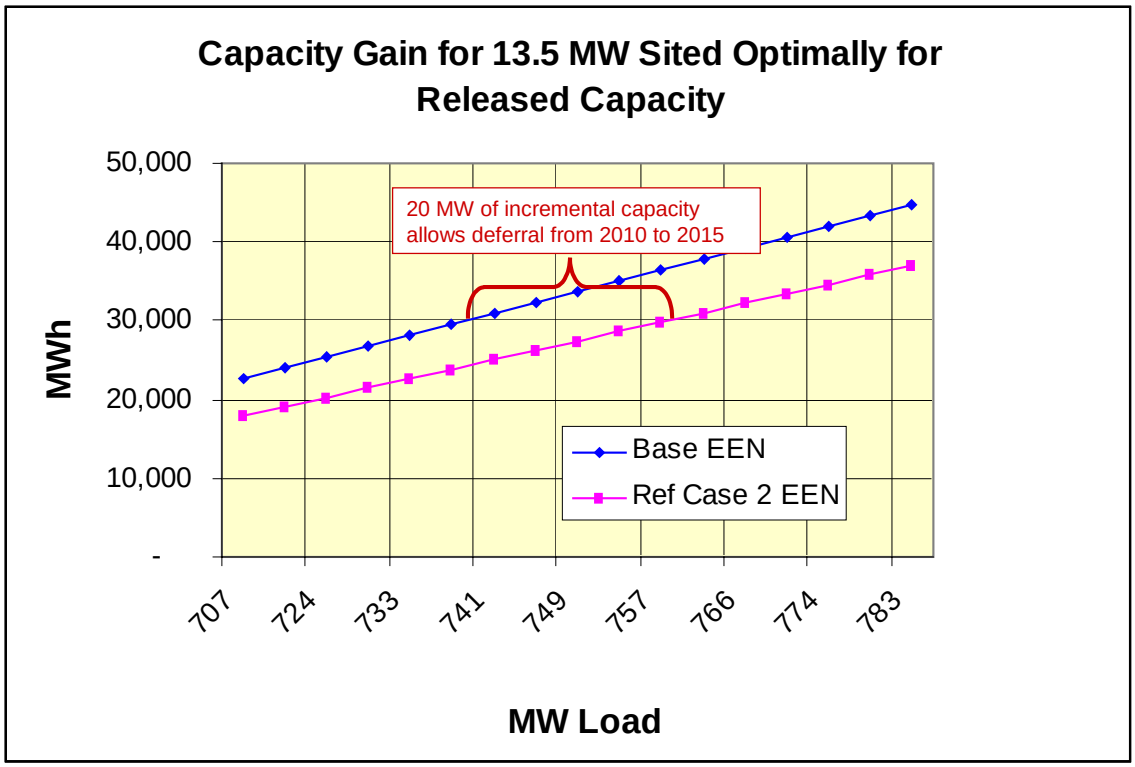

Figure 66: EEN-Based T&D Deferral

Under the base case, 30,000 MWh of EEN would occur at a system load of approximately 740 MW. Given Area B load forecasts, a system load of approximately 740 MW will be achieved in 2010. But with the 13.5 MW of optimally-sited RDG, 30,000 MWh of EEN does not occur until system load has reached almost 760 MW, a gain of roughly 20 MW of incremental capacity, and a level of system load not expected until 2015. The 20 MW capacity gain would thus allow EEN-related system upgrades to be deferred for five years without increasing EEN over the base case. Thus, the Sylvan-Auburn substation, scheduled for installation in 2010, could be deferred until 2015 while maintaining the same level of reliability as measured by EEN (this analysis assumes that the general Area B EEN characteristics are applicable to the Sylvan-Auburn substation area).

The Present Worth method deferral value is given by:

$$PW = \sum \left[\frac{Invest}{(1+r)_y} - \frac{Invest * (1+i)_{\Delta y}}{(1+r)_{y+\Delta y}} \right]$$

where:

Invest = annual demand-related investments in capacity by area ($)
i = escalation rate for the investments
r = discount rate; y = year
Δy = years of deferral

Using the equation above, we calculate the deferral value of delaying the construction of the Sylvan-Auburn substation for five years. If we use the deferrable value of the substation construction of $500,000 and assume that the construction start date is delayed from 2010 to 2015, the resulting total deferral value (or benefit) is $56,000 for the 13.5 MW Reference Case 2 shown in Figure 66.[7] Obviously, if other planned distribution investments can also be deferred because of the reliability improvement gained from the addition of RDG, this value can be much greater.

5.5.3. VRI and Deferral Benefit Interaction

Unlike VRI, deferral benefit is a 'direct' cost savings attributable to the installation of RDG. Care must be taken, however, to properly account for changes in VRI in combination with T&D deferral. Figure 67 plots EEN for a hypothetical T&D expansion project with and without DG. The dotted line represents EEN with DG installed. It shows that EEN is lowered in region A as the DG lowers the peak loads in the area. As EEN relates directly to VRI, region A represents VRI due to DG. Because of the DG, the utility is able to delay the T&D expansion project. There is a benefit to the utility from the delay, but a penalty to customers through negative VRI in region B. When the T&D expansion is completed, the EEN is lowered significantly. The deferral delays this reduction in EEN and hence results in higher outage risk during the deferral period (see region B). Ultimately, however, once the T&D project is completed, customers will be better off due to a combination of the RDG and the T&D project. This period of higher reliability is represented by region C in the figure. So the net change in VRI in this case is VRI[region A] – VRI [region B] + VRI[region c].

[7] Assumes year one (y) = 2004, the inflation rate (i) = 2.4% and the discount rate for SMUD (r) = 6%.

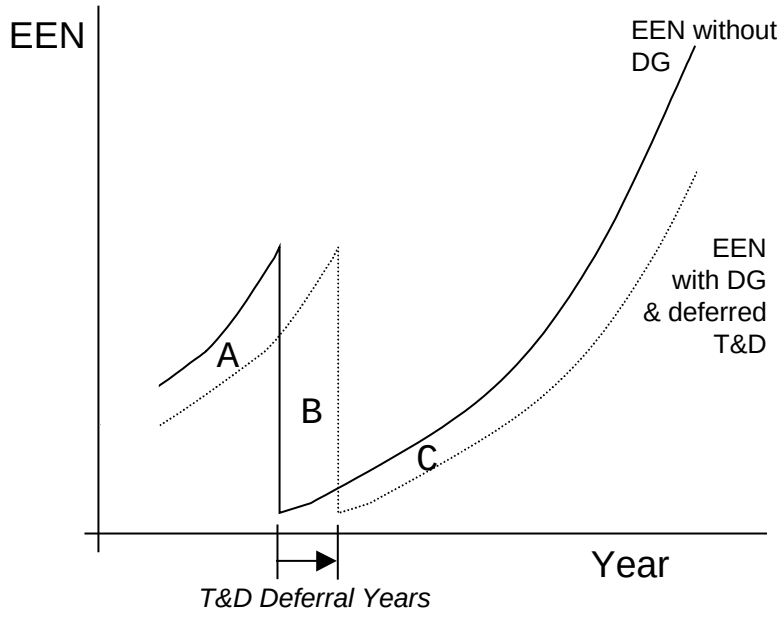

Figure 67: VRI and T&D Deferral

Continuing with the deferral example used above for the Sylvan-Auburn substation, region A would contain the period from 2005 (assuming the 13.5 MW RDG is installed immediately) to 2010, when the upgrade would have been installed. Region B would contain the period from 2010 to 2015, when the deferred upgrade is finally installed. And Region C would contain the period beyond 2015, after the deferred substation is installed.

5.5.4. Additional Uses of Reliability Valuations

This section discusses additional applications of the economic valuation of reliability. While we do not recommend these approaches, they are provided for completeness.

5.5.4.1. Relative Customer VRI

The Relative Customer VRI method compares projects to establish the relative impact of DG on multiple projects. VOS varies by customer class, so to the extent that the class composition varies across projects, the incorporation of VOS could provide rankings that differ from what would result from a simple comparison of EUE or EEN values.

The Relative Customer VRI method allows planners to rank and prioritize projects to assist in the management of limited resources and budget constraints by developing measures of the potential cost to customers of changes in expected reliability. The Relative Customer VRI method starts with the calculation of the value of reliability improvement due to the installation of DG.

$$VRI_t = \sum_c \Delta EUE_t \cdot Class\%_{c,t} \cdot VOS_c$$

where:

EUE is the change in EUE due to the implementation of DG

Class% is the percentage of peak usage for each customer class

VOS is the customer value of service

c is the customer class

t is the year

ΔEUE can be calculated based on contingency cases and emergency ratings, or outage probabilities and EEN (as applied earlier in this section).

Once the change in outage cost is monetized, the planner has several choices for ranking metrics, each of which has its merits, depending upon the budget and resource issues facing the utility at the time.

- VRI can be used directly to identify the opportunities for the largest reduction in outage costs.
- VRI / DG Cost identifies the highest 'bang for the buck' from the DG investment budget.
- VRI /DG Net Cost would identify the DG application that is most 'cost effective,' with cost effectiveness being a function of the policy choice of 'cost effective to whom?' The issue of cost test perspectives is covered in detail in the Economic Screening Analysis chapter.

5.5.4.2. VRI for Project Justification

The natural extension of the Relative Customer VRI method would be to compare the value of the reliability improvement to the cost of the DG or even the cost of the traditional T&D solution. The problem with this application is that there is typically a disconnect between the engineering standards and the reliability levels that would be indicated by the VOS numbers. Generally speaking, reliance upon VOS numbers would result in declining reliability as projects would not appear justified based on those numbers.

This does not necessarily mean that existing systems are overbuilt or that current reliability levels are too high. Overturning decades of engineering standards because of VOS results is not warranted for two main reasons.

- As discussed earlier, VOS numbers are difficult to attain and highly variable in their reported levels. While these shortcomings can be accepted when looking at the relative impact of different levels of reliability, it would be troubling to use these numbers to establish absolute levels of reliability.
- VOS numbers focus on the direct impact on individual customers and fail to recognize the larger effects that degraded reliability can have on a local

community. For example, low reliability could force businesses to leave the area, resulting in a ripple effect through the community from fewer jobs, less demand for the service industries patronized by those workers, lowering of property values etc.

Because of these limitations, we have included this method for the purpose of completeness. We do not recommend its use at this time.

6.0 Uncertainty Analysis

The RDG Assessment project results described in the Economic Screening Analysis are driven by Base Case input data. The resulting conclusions are subject to uncertainty given variability in input assumptions used throughout the analysis. E3 developed uncertainty analysis to test how alternate scenarios for several key input data would affect the overall results of the assessment. This report describes the method we used to test the sensitivity of the RDG Assessment results to particular ranges of uncertainty in the inputs. We built this testing process into the RDG screening tool so that users can easily observe the potential robustness of their results under uncertainty and subsequently improve their information for decision-making and planning.

6.1. Scenario Analysis for Key Inputs

We established automated sensitivity tests in the RDG screening tool to analyze the effect of alternative values for the following seven key input assumptions:

- generation market prices
- transmission prices
- distribution avoided costs
- DG capital costs
- fuel costs
- capacity factor
- rates

We developed the model so that in each case, the user may select a Base, High, or Low scenario and immediately observe the effect of this change on the results. The degree of change under each scenario can also be input by the user.

6.1.1. Generation Market Prices

In order to observe sensitivity effects of uncertain generation market prices, we varied the avoided generation costs. In this case, we hold both the High and Low scenario equal to the Base Case through 2008 because our forecast during this period is based on forward price quotes, and therefore represents a fully hedged position. For 2009 and beyond, when we rely on the CEC gas forecast to help derive the Long-Run Marginal Cost (LRMC) for electricity, the Base, Low, and High electricity price forecasts are derived using the CEC Base, Low, and High gas forecasts in our LRMC calculations. The resulting Base, High, and Low electricity price forecasts are shown in Figure 68.

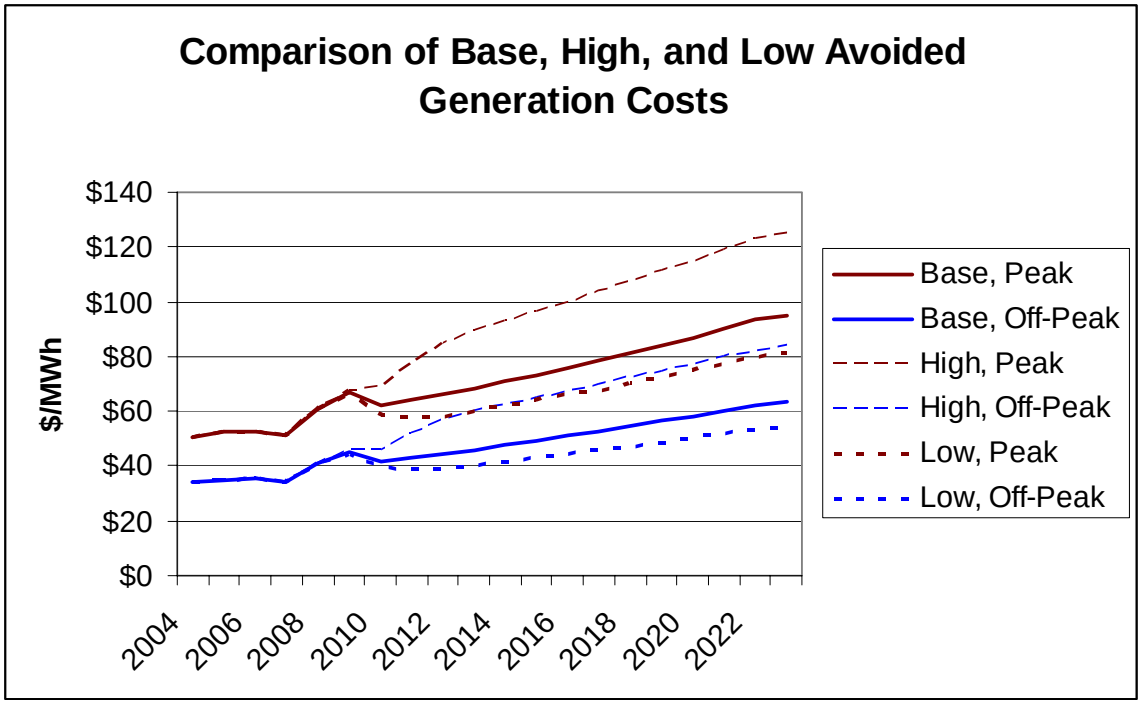

Figure 68: Comparison Of Base, High, And Low Avoided Generation Costs

6.1.2. Transmission Prices

In the case of uncertain transmission prices, we used a Base Case value equal to current avoidable transmission costs of $2.22/MWh. Because transmission prices are unlikely to decline, we use the same value for our Low scenario. We input a High value at $15/MWh, reflecting considerable uncertainty surrounding the possibility of 'nodal' pricing under MD02, as discussed in the Distribution Avoided Cost chapter, below.

6.1.3. Distribution Avoided Costs

To address uncertainty in distribution avoided costs, we allow for scenario testing of two variables that impact distribution avoided costs: distribution project capital costs and annual growth rate on the feeder. In this way, project capital costs are set as a default to vary by plus or minus 20%. However, this value may be adjusted more specifically by the analyst to incorporate the uncertainty surrounding a particular investment project. The analyst may also input different scenarios for MW growth on the distribution system being analyzed. The growth rate has an impact on distribution avoided costs because for a given RDG installation, a higher growth rate means fewer years of deferral. The average growth rate for the Base Case in the Sylvan-Auburn substation area (the location of the identified deferrable distribution project) is 0.38 MW/year. We used 1.0 MW/year as the High scenario and 0.1 MW/year for the Low scenario.

6.1.4. RDG Capital Costs, Fuel Costs, and Capacity Factors

As a default in the screening tool, RDG capital costs, fuel costs, and capacity factor are varied by plus or minus 20% of the base case. These default assumptions can be revised by technology as more specific information is gained. Marginal rates were set to be 10% higher in the High scenario, and 20% lower in the Low scenario. The asymmetry is due to the rate structure and our base case assumptions: changing the capacity factor and other assumptions that drive our marginal rate calculation can have a greater effect on the low side of our Base Case assumptions than on the high side.

6.2. Results of Uncertainty Analysis

In this section, we provide the results from testing the uncertainty around the base case results from three different RDG technologies: an 800 kW biogas unit, a 50 kW solar PV unit, and a 500 kW biodiesel generator. There are numerous RDG technologies included in the model and each of these can be tested in a similar way.

6.2.1. 800 kW Biogas

Figure 69 shows the range of TRC test results obtained for an 800 kW biogas generator with CHP by varying each key input while holding all others at the Base Case. Although we vary only one input at a time in this example, multiple inputs can be varied at the same time using the RDG screening tool.

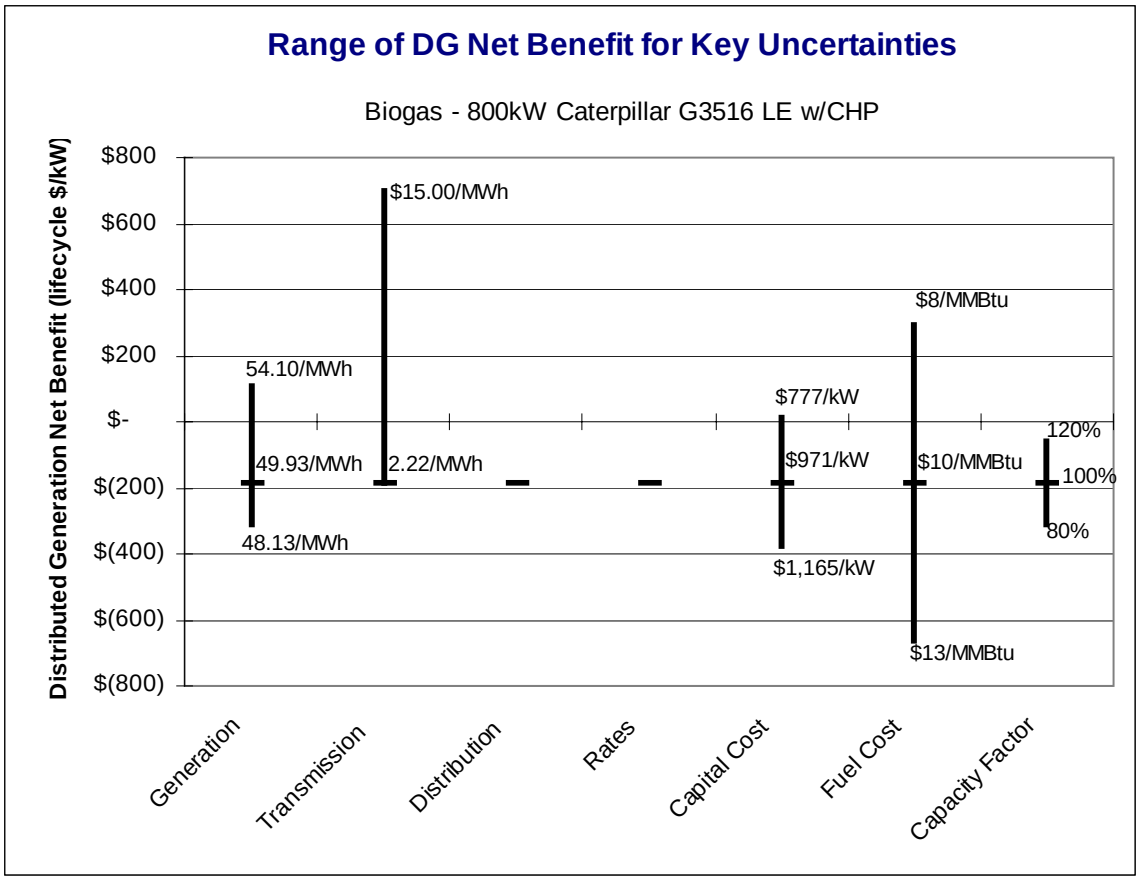

Figure 69: Net Benefit Range For Key Uncertainties From The TRC Test Perspective

As can be observed in Figure 69, the 800 kW biogas unit we screened is not cost-effective under the TRC test in the Base Case (the central tick marks) but can become cost-effective under several scenarios: high electricity market prices; high transmission prices, low capital costs; or low fuel costs. The fact that this technology can become cost-effective within the range of so many of the tested variables suggests that more detailed analysis of the technology may be warranted.

Figure 70 shows the results of the TRC test sensitivity analysis in the form of a 'spider diagram.' As in Figure 69, one can easily discern the effect of a move from Base to High or Low scenarios for any of the input variables. The nucleus of the spider diagram is the Base Case scenario and each 'leg of the spider' represents the effects on the overall net benefit of the RDG installation of a change in that variable while holding all other variables at the Base Case. The spider diagram also allows the reader to discern how large a change in the variable was required to effect the change.

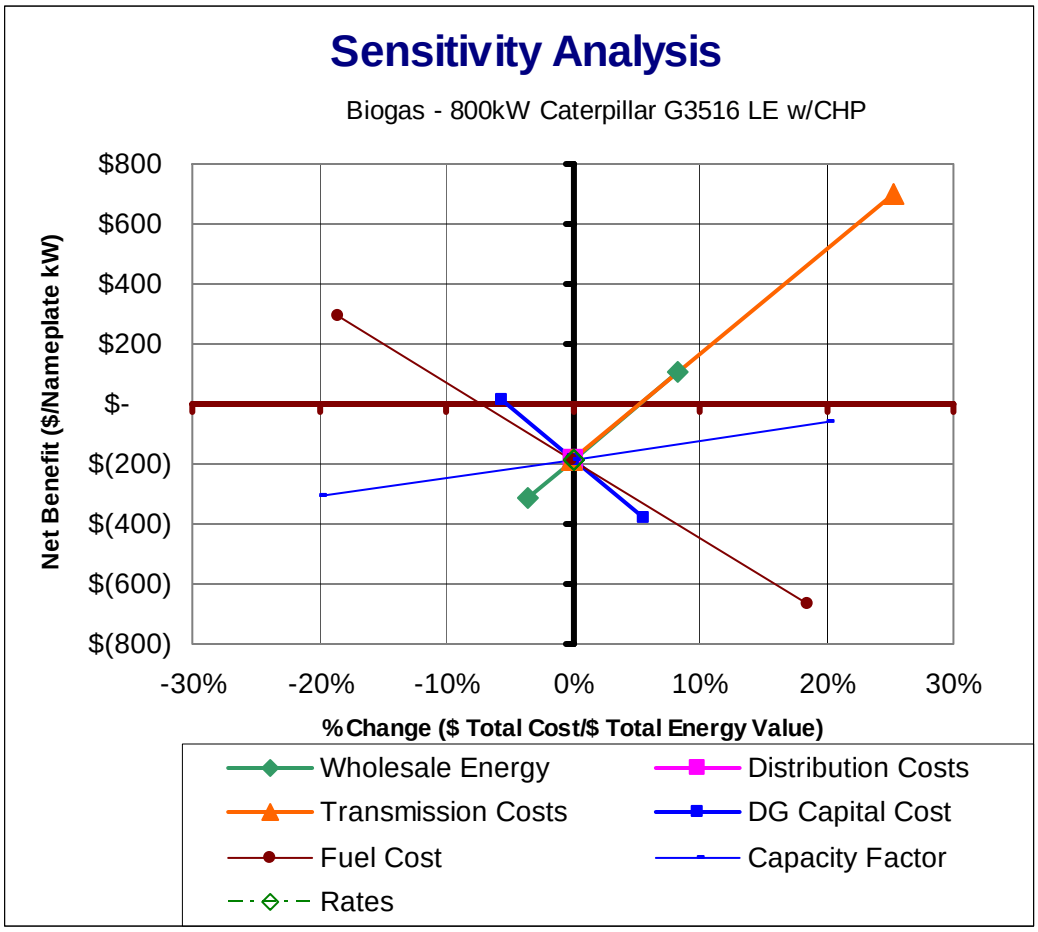

Figure 70: Sensitivity Analysis For 800 Kw Biogas Generator With CHP From The TRC Test Perspective

The percentage change along the horizontal access is expressed as the change in the lifecycle value of the variable being tested, relative to the change in lifecycle value of the generation output of the unit. This generation output value is calculated as the generation unit's hours of operation multiplied by the forecasted wholesale generation price on a lifecycle basis. In the case of transmission prices, these vary in our analysis from $2.22/MWh in the Base Case to $15.00/MWh in the High case. While this is an increase in the transmission price of over 600%, the sensitivity ratio is calculated as:

$$\% \text{ Change} = (T_H - T_B) \,/\, (\text{G Output}_B) = 25\%$$

where:

T = lifecycle transmission avoided cost value

G Output = lifecycle value of generation savings given the unit's output

H = High Scenario

B = Base Scenario

The one exception to this equation is the capacity factor, which is expressed as percentage change relative to its own base case.

For the 800 kW biogas unit, fuel costs and transmission costs under the scenario analysis change by a significant amount relative to the generation value of the unit's output. DG capital cost, in contrast, makes up a smaller percentage of overall costs, so a variation of plus or minus 20% in the DG capital cost is relatively small when expressed as a percentage of the generation value. Nevertheless, the relatively small variation in DG capital cost is still significant enough to push the technology into the cost-effective range under the Low capital cost scenario.

6.2.2. 50 kW Solar PV

For a 50 kW solar PV system, the most important driver of results in the sensitivity analysis is capital cost, as can be observed in both Figure 71 and Figure 72 . The high capital cost per unit of output dwarfs the other variables so that a rise or fall in the capital costs has a significant effect on total costs, and therefore on the overall cost-effectiveness of the technology. Nevertheless, the technology proves not to be cost-effective even under the Low capital cost scenario.

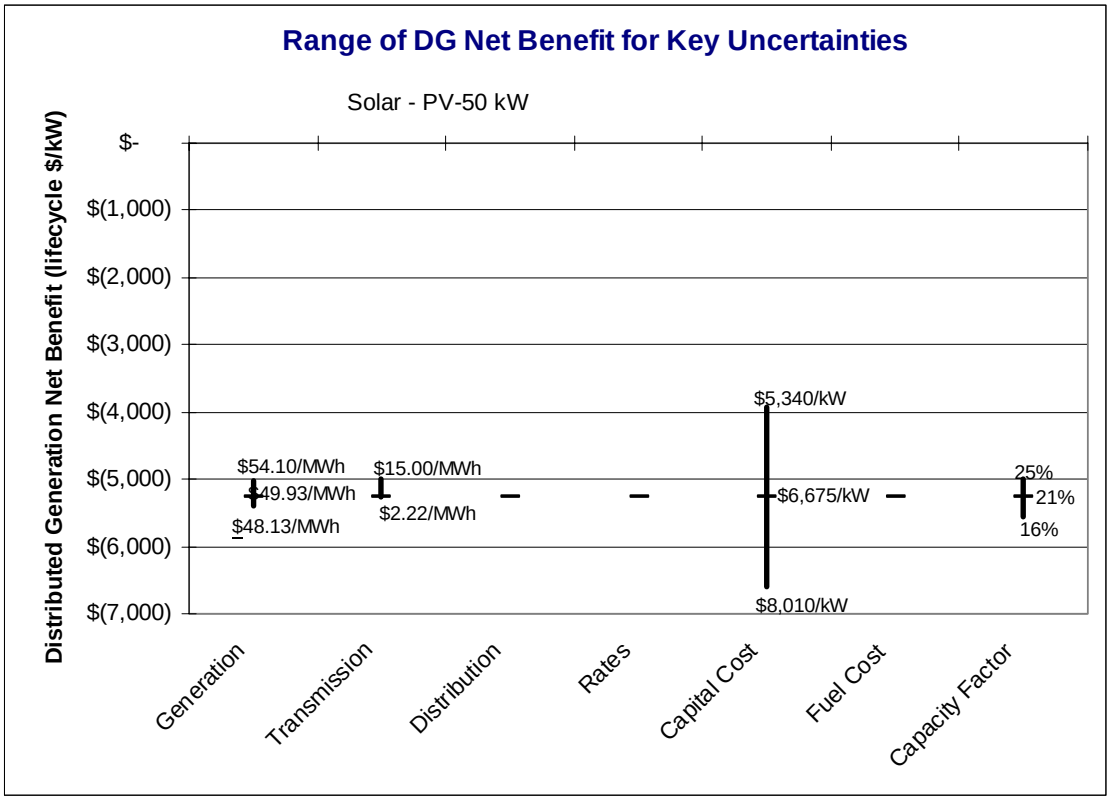

Figure 71: Range Of Net Benefits For 50 Kw Solar PV From The TRC Test Perspective

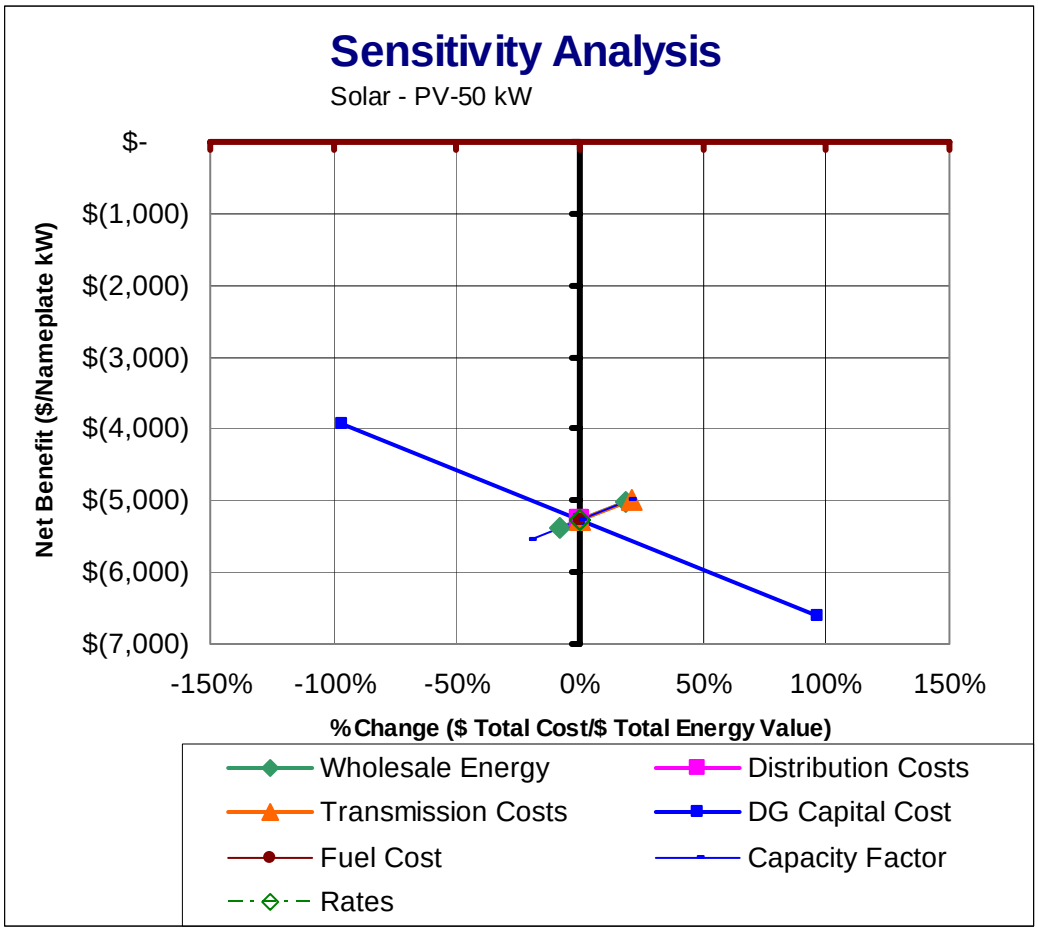

Figure 72: Sensitivity Analysis For 50 Kw Solar PV From The TRC Test Perspective

6.2.3. 500 kW Biodiesel

Figure 73 shows the sensitivity results for a 500 kW biodiesel generator in the form of a spider diagram.

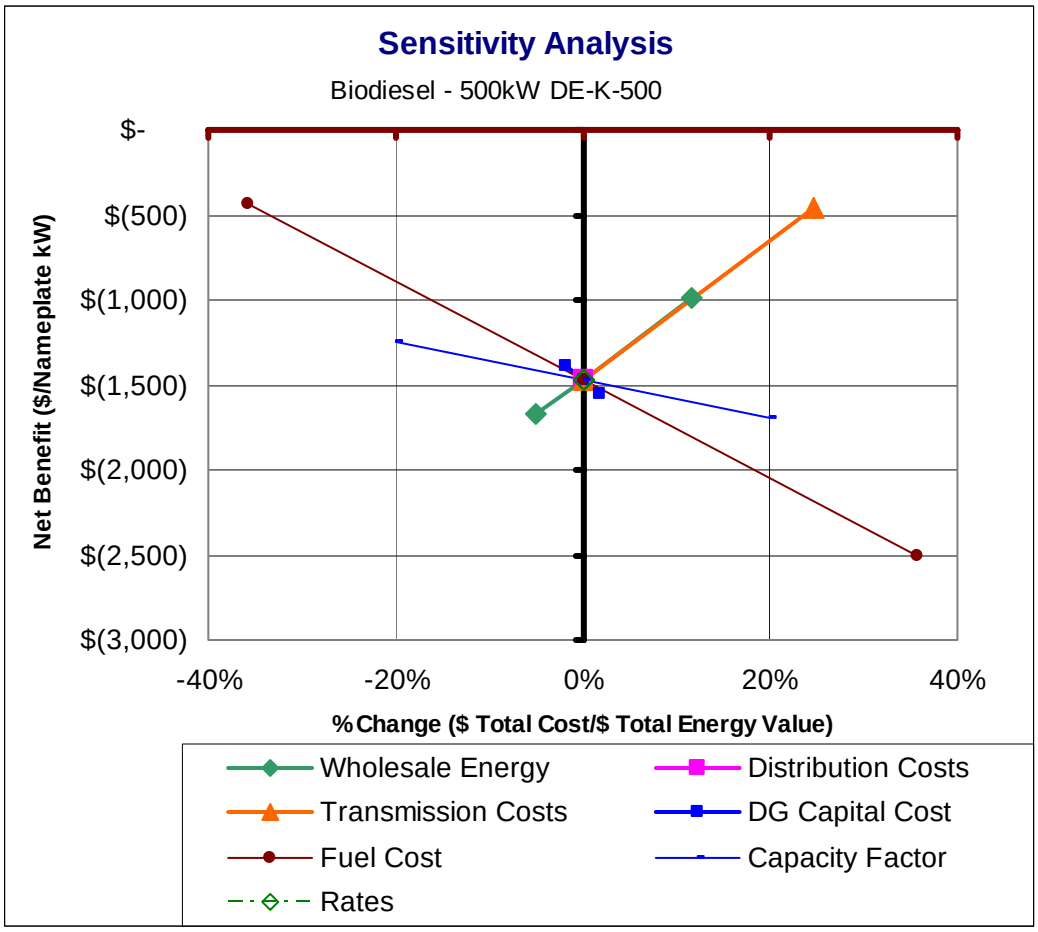

Figure 73: Sensitivity Analysis For A 500 Kw Biodiesel Generator From The TRC Test Perspective

Changing any single variable within our sensitivity ranges while holding all others at the Base Case does not cause this technology to become cost-effective under the TRC test. However, the confluence of several variables moving in a 'favorable' direction can cause the unit to become cost-effective under the TRC test. Figure 74 shows the results of the economic screening when Generation Market Prices are set to 'High,' Transmission Prices are set to 'High,' and Fuel Costs are set to 'Low,' while all other variables are held at the Base Case. In this case, the technology passes the TRC test by a good margin, with a B/C ratio of 1.25.

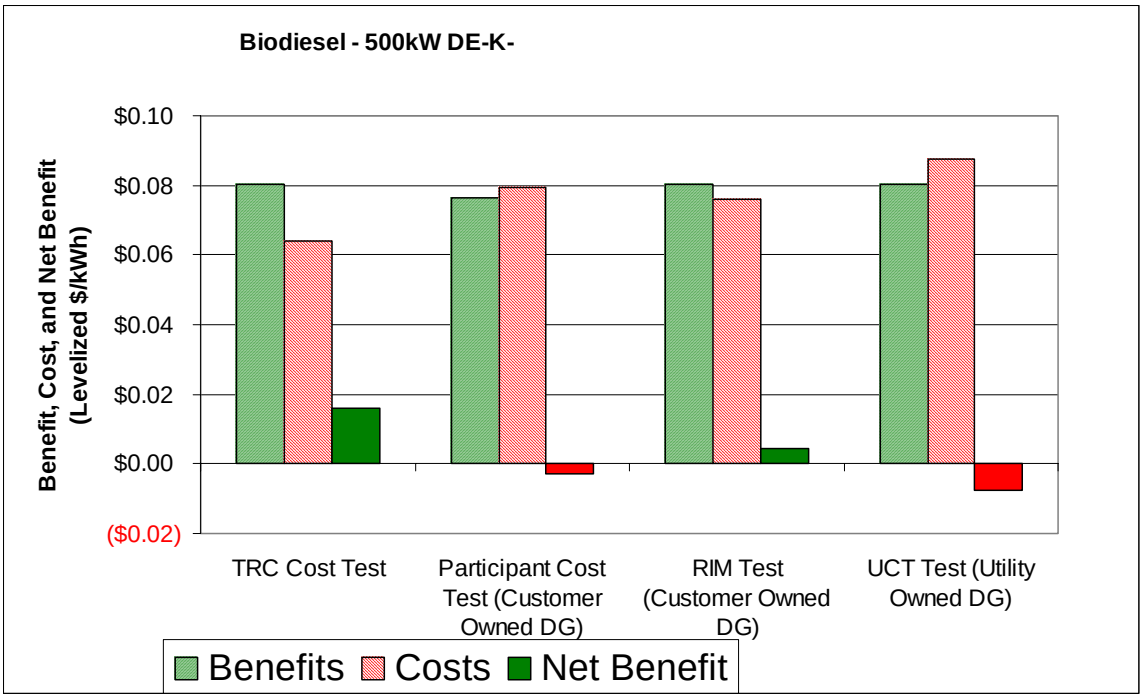

Figure 74: Economic Screening Results For A 500 Kw Biodiesel Generator With 'High' Market Prices, 'High' Transmission Costs, And 'Low' Fuel Costs

7.0 Conclusions

The results of the SMUD case study RDG Assessment project are two-fold. First, this project represents a successful application of the RDG Assessment methodology developed by E3 and ETK. Second, the results provide SMUD with valuable information for future decision making that includes the specific benefits RDG could provide on their distribution system.

A summary of the assessment results presented in this report include the following:

- *It is difficult to find cost-effective RDG.* Certain opportunities do exist, but they require an array of favorable circumstances to generate net benefits.
- *Two of the three cost-effective technologies identified were combined heat & power (CHP).* The ability to capture and use waste heat creates an additional income stream for RDG projects that can tip the balance towards cost-effectiveness. CHP is only an option with combustion-based RDG technologies.
- *The modeling of a 1.5 MW wind turbine resulted in the third cost-effective technology.* Even though a wind turbine of this size is technically not distributed, if an adequate wind resource exists in SMUD territory, this could result in a cost-effective renewable project.
- *RDG's ability to defer distribution projects can provide economic benefits.* However, the overall effect of the distribution deferral benefits is expected to be modest.

Engineering Screening

- No likely operational problems (e.g. voltage/overcurrent) were indicated for the three RDG cases we evaluated. Among these, we note that:
    - 13.5 MW of RDG sited for loss reduction resulted in a net peak incremental loss reduction of 5%.
    - 20 MW of dispersed solar PV resulted in only 2% peak loss reduction.
    - 13.5 MW DG sited for released capacity is likely best for reliability improvement from feeder capacity.

Reliability Screening

- Solar PV can achieve a high (45%) incremental capacity value due to high coincidence with SMUD's summer peak.
- Well-sited RDG yields a 3-4% reliability 'bonus' when operating at peak load due to reducing losses as well as supplying load.
- Well-sited dispatchable RDG can yield incremental capacity increases of two to three times the generation output.

Upon initiation of this research project, the specific goals in the five-year, ten-year, and fifteen-year timeframe were identified. These included development of a robust methodology to evaluate local area resources and moving this type of analysis towards

standard industry practice. The completion of the SMUD RDG Assessment represents the first step in achieving these goals.

Recommendations including the implications of the use of this methodology in California and proposed next steps are described in the Final Report for the Renewable Distributed Generation Assessment project. This report captures the results from all four applications of this newly developed evaluation methodology.

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GLOSSARY

CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DG	Distributed Generation
EEN	Energy Exceeding Normal
EUE	Expected Unserved Energy
LRMC	Long Run Marginal Cost
MW	Megawatt
NYMEX	New York Mercantile Exchange
PG&E	Pacific Gas and Electric Corporation
PV	Photovoltaics
RDG	Renewable Distributed Generation
RIM	Ratepayer Impact Model
T&D	Transmission and Distribution
TOU	Time of Use
TRC	Total Resource Cost Test
UCT	Utility Cost Test
UE	Unserved Energy
VOS	Value of Service

APPENDIX A: COST AND PERFORMANCE OF RENEWABLE DG TECHNOLOGIES

1.0 Appendix A:
Cost and Performance of Renewable DG Technologies

Renewable energy technologies are best categorized by their energy source or 'fuel': solar, wind, hydro, geothermal, or biomass. For each fuel, various energy conversion technologies exhibit distinct strengths and weaknesses, and not all are well-suited to DG applications. Solar PV and microturbines, for example, are particularly suited to addressing localized distribution requirements, while wind and geothermal require larger, site-specific installations.

Below we briefly describe the performance and cost characteristics of each technology and present a table with key performance data used in our economic analysis.

1.1.1. Solar

Solar technologies fall into two categories: photovoltaic (PV) and thermal. The former employs an array of semiconducting wafers or film that directly generate DC current from incident sunlight. Owing to their modular nature, these arrays are highly scalable. While their output is dependent upon intermittent sunlight, it often coincides with summer peak loads. Real estate for larger installations can be a significant expense, which has prompted the development of unused industrial and commercial rooftops.

Solar-thermal or concentrated solar power (CSP) technologies employ heat to generate power. They consist of a solar concentrator, typically an array of mirrors, and a power converter (such as a turbine), which ultimately drives a generator to produce electricity. Most common among these is the 'solar trough' configuration, in which a parabolically shaped trough of reflective material focuses light on a piped fluid. Though the energy source is intermittent, the heat sink fluid can be stored, allowing these technologies to offer high-value dispatchable power. But given their dependence on economies of scale, these technologies are best suited to multi-megawatt installations[1].

Solar dish engines, however, offer greater modularity in a solar-thermal technology. They use an all-in-one power conversion system that typically uses a Sterling engine-generator to convert heat to electricity. Individual units range from 9-25 kW. Like all solar-thermal technologies, while presently expensive, they employ relatively conventional components that show promise of improving economic competitiveness in the near term.

1.1.2. Wind

Wind energy technologies convert the kinetic energy of moving air into electricity via an airfoil that drives an electric generator. Despite their apparent similarities, wind turbines vary significantly in their size and kind of electrical output. Since the R&D boom of the early 1980's, the upwind, horizontal-axis design has come to predominate. Rotor diameters range from two arm spans (1 kW) to nearly four hundred feet (5 MW), and towers vary similarly in height. However, the smaller wind turbines are significantly less efficient, and wind economics greatly benefit from installations greater than 20 MW. In today's market, the large wind farms that capture economies of scale, combined with a Federal Production Tax Credit of $1.8 cents/kWh and other tax incentives, are cost-effective yet site-specific. Wind turbines typically produce AC power via induction or synchronous generators. Induction generators are simpler, but require reactive power from the grid, while

[1] http://www.energylan.sandia.gov/sunlab/overview.htm#tower

synchronous generators require advanced power conversion electronics, but can generate more energy for a given wind regime. Aesthetic appraisals of wind turbines range from elegant to unsightly, and some wind turbines create low-frequency noise, which may affect siting considerations. Avian mortality has been another concern for wind power, especially in the Altamont region, though mortality rates have fallen sharply with the preponderance of larger, slower-spinning turbines mounted on tubular instead of lattice towers.

1.1.3. Hydro

Hydroelectric dams, which convert the potential energy of stored water into electricity via a turbine, produce most of the renewable electricity in California today. Almost all suitable dam sites have already been developed in California, and permitting is becoming ever-more expensive and time consuming.

In contrast, 'micro' hydro technologies do not require dams and operate on a 'run-of-the-river' basis. As such, these hydro technologies are not dispatchable technologies. The option we consider here converts the kinetic energy of extant municipal water flows into electricity.

1.1.4. Geothermal

Heat and/or pressure extracted from subsurface water and permeable rock can be converted to electricity via steam powered turbine-generators. Wells typically range from one to several miles beneath the Earth's surface. While this form of renewable energy generation can offer affordable and dispatchable power in the 20-80 MW size, it is highly site-specific, and is thus not well suited to distributed generation.

1.1.5. Biomass

Organic residues from landfills, agricultural waste, timber scraps, etc. can be converted thermochemically or biochemically into electricity through a variety of energy conversion pathways. Most commonly, a biomass supply is purified into a fuel and then burned in a turbine or engine that would typically consume fossil fuels. The best biomass solution depends upon the fuels and technologies at hand. We have included biodiesel and biogas technologies in the Screening Model.

1.1.5.1. Biodiesel

Vegetable oils and animal fats can be chemically converted into biodiesel, which will power compression-ignition (diesel) engines with little or no modifications. In addition to emitting fewer particulates, unburned hydrocarbons, carbon monoxide, and oxides of sulfur than conventional diesel, biodiesel is renewable. It also offers superior lubricity with equal BTU content. Emissions of nitrogen oxides can be slightly more or less, depending on the engine’s duty cycle. Biodiesel is most commonly combined with petroleum-based diesel in a 20% biodiesel mixture (known as B20); higher percentage blends can impact elastomer- and rubber-based fuel system components (though these are being phased out as new diesel standards take effect). Biodiesel is currently slightly more expensive than its petroleum counterpart, and is available nationwide. Biodiesel meets the clean diesel standards established by the California Air Resources Board.

1.1.5.2. Biogas

Solid biomass such as timber waste can be directly burned or co-fired with coal to power a steam turbine-generator, reducing net carbon emissions. Municipal solid waste (MSW) and other forms of biomass can also be converted into fuel via the following methods:

- Gasification The substance is heated in the absence of oxygen to produce a mixture of hydrogen, carbon monoxide, and methane.
- Anaerobic digestion Bacteria consume the biomass and produce methane. This occurs naturally in landfills.
- Pyrolysis A chemical/thermal process, this produces an oil similar to diesel, though with less energy content.

Landfill gases, principally composed of equal parts methane and carbon dioxide, can also be collected, filtered, and converted to electricity. Whichever pathway is selected, the resultant fuel can then be burned in a reciprocating engine, microturbine, or fuel cell.

1.1.5.3. Biomass Fuel Prices

Short transportation distances from the biomass supply to the power generation point are critical to the economic viability of producing electricity from biofuels. Feedstock price, which can also vary widely, has the greatest influence on the price of biodiesel—production costs alone span a six-fold range. Average U.S. wholesale biodiesel prices in early 2004 are $1.18/gal ($8.58/mmBTU) for B20 and $2.12/gal ($15.41/mmBTU) for B100.

In the case of MSW gasification, consistent data on the feedstock price is still scarce. The economics of landfill gas-to-energy has been more consistently studied, though the price of the feedstock depends on the difficulty of harvesting the resource, and the quality of the recovered gas. The EPA observes that prices typically range from $6-13/mmBTU for landfill methane. We have used the average value as the default in our Screening Tool.

1.1.5.4. Fuel Cells

These solid-state devices convert chemical energy directly into electricity very efficiently and with negligible emissions. While the technology is not new, it is just beginning to be commercialized. Inside each fuel cell, a catalyst is used to create electricity from a fuel such as hydrogen. The fuel cell end products include water, heat, and electricity. Hydrogen can be obtained from methane via reformation, a thermo-chemical process which can take place inside some designs, and in an auxiliary unit with others. Fuel cells are categorized by their electrolyte and their operating temperature. The four major types are:

Phosphoric Acid (PAFC) These have been commercially available since the early 1990's. They operate around 200°C. PAFCs require an external reformer.

Proton Exchange Membrane (PEMFC) These low-temperature (65-85°C) fuel cells have received major R&D from the automotive industry. Small 1-5kW models for home are available in Japan and Germany, and will be available in the U.S., along with larger sizes, in the next few years. PEMFCs offer high power densities and can vary their load quickly to meet fluctuating demand. However, they require pure, externally reformed hydrogen.

Molten Carbonate (MCFC) Due to their operating temperature of nearly 700°C, MCFCs hold promise for CHP and DG applications, as they can internally reform methane into hydrogen. They have just begun to be commercially available.

Solid Oxide (SOFC) Generally considered to be less mature than MCFCs or PAFCs, SOFCs offer high reliability and efficiency, in addition to high operating temperatures (750-1,000°C), which make internal reforming possible. 2005 should see the first commercially available SOFCs.

1.1.6. Performance characteristics

Below we present a matrix summarizing the performance, cost, and other important attributes of renewable technologies. Some are particularly suited to addressing localized distribution requirements (e.g. solar PV, microturbines), while others require larger, site-specific installations (e.g. wind, geothermal). Hybridizing these technologies may provide additional benefits. Combining PV with fuel cells, for example, may offer a way to address intermittency while maintaining a low emissions footprint.

	Solar PV	Solar Thermal (CSP)	Wind	Hydro	Low-temp fuel cell	High-temp fuel cell	Micro-turbine	Diesel Recip Engine	Gas-fired CCGT
Size (MW)	0.001-0.10	.025 - 80	0.05-3.0		0.001-0.25	0.25-3	0.025-0.30	0.05-10	50-250
Fuel	none	none	none	none	biogas	biogas	biogas	biodiesel	gas
Installed Cost ($/kW)	6,675-8,650	5,700	1,000-6,000	N/a	5,346-12,507	5,731-8,338	2,200-2,600	250-500	350-450
Heat rate (Btu/kWh)	N/a	N/a	N/a	N/a	9000-10,000	7000-8000	11,000-14,000	8000-11,000	7000
O&M ($/MWh)	5	10 - 23.0	10	N/a	15	10	10	20	5
Cogeneration (Btu/kWh)	0		0	0	4000-5000	1500-3000	5000-8000	3000-5000	0
NOx emissions (lb/MWh)	0	0	0	0	0.02	0.01	1	15-20	0.06
CO2 emissions (tC/MWh)	0	0	0	0	0.13-0.15	0.10-0.12	0.16-0.20	0.12-0.16	0.1
Construction Time	days	months	weeks	years	days	weeks	days	days	months
Average Annual Capacity Factor (%)	22%	24%	36%	42%	96%	96%	96%	95%	99%
Start-up time (sec)	intermittent	intermittent	intermittent	"Fast"	“Fast”	“Slow”	120	10	600-1800
Dispatchable?	No, but coincident w/ peak loads	No, but coincident w/ peak loads	No	Yes	Yes	Yes	Yes	Yes	Yes
Load following?	Yes, w/ storage	Yes, w/ storage	No	Yes	Yes	Limited	Yes	Yes	Yes
Noise problem?	no	no	Possible	no	Unlikely	Unlikely	Possible	Likely	Unlikely