Arnold Schwarzenegger
Governor

Renewable Distributed Generation Assessment: Alameda Power and Telecom Case Study

PIER FINAL PROJECT REPORT

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Prepared By:

Energy and Environmental Economics, Inc.
Electrotek Concepts, Inc.

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Prepared By:

Snuller Price, Carmen Baskette, Mike King, Debra Lloyd, Brian Horii, and Peter Light of E3
Energy and Environmental Economics, Inc.
San Francisco, California

Roger Dugan and Lee King
Electrotek Concepts, Inc.
Knoxville, Tennessee

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California Energy Commission

Public Interest Energy Research (PIER) Program

Dave Michel,
Contract Manager

George Simons,
Program Area Team Lead
Renewable Energy Technologies

Ron Kukulka,
Acting Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Robert L. Therkelsen
Executive Director

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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 through the Year 2001 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 case study 1 of 4 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: Alameda Power and Telecom 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 first application of a renewable distributed generation assessment methodology conducted for Alameda Power and Telecom (Alameda P&T). Alameda P&T 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 Alameda P&T, the three other distribution systems evaluated include the City of Palo Alto Utilities (CPAU), San Francisco PUC / Hetch Hetchy, and Sacramento Municipal Utility District. 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, Alameda Power & Telecom, avoided costs, reliability analysis, uncertainty analysis

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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.

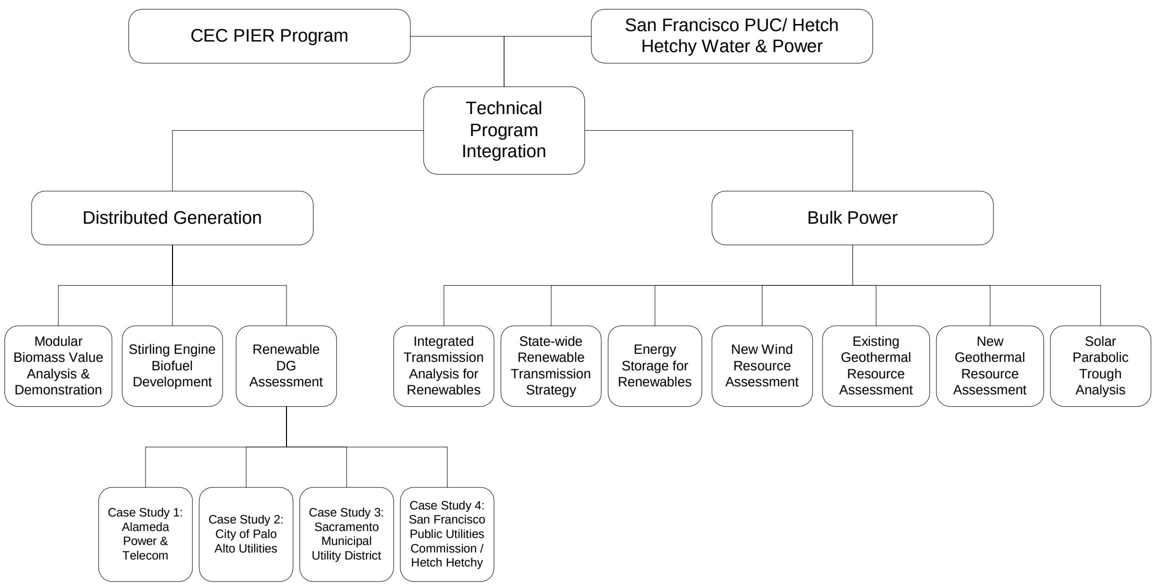

Figure 1: CEC PIER Program Research Project Structure

The following discussion comprises one of four case studies for the application of the RDG Assessment methodology. This case study describes the analytical process and associated results for the Alameda Power and Telecom (Alameda P&T) 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), City of Palo Alto Utilities (CPAU), and Sacramento Municipal Utilities District (SMUD).

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 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, (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 and readily accessible tools for rapid assessment of distributed renewable technologies that can be applied to any distribution network.

Results

The results of the Alameda P&T 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 Alameda P&T 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:

- Alameda P&T system could accommodate approximately 30 MW of uniformly distributed RDG without significant changes.
- Beneficial generation must be able to produce power in the early evening hours in winter months because Alameda P&T is a winter peaking utility. This casts doubt on the benefits of solar PV technologies to the power delivery system unless coupled with significant storage.
- Applications of RDG on Bay Farm Island would appear to offer the greatest potential benefit due to the distance of that load from the substation.
- Most of the areas on the main island of Alameda offer potential benefits for RDG siting due to the distance from the substation and some of the bayside commercial areas on the opposite side of the island from the Jenney substation have potential benefits similar to Bay Farm Island locations.
- The most cost-effective RDG technologies for Alameda P&T from a total resource perspective are biogas generators operating as combined heat and power resources.
- Large-scale wind is also a cost-effective renewable resource but a sufficient wind resource is not available within Alameda to support this technology as a local distributed energy resource.
- Reliability benefits are relatively small because Alameda P&T has sufficient system capacity available at present.

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 Alameda P&T 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.

ALAMEDA CASE STUDY

1.0 Introduction

This California Energy Commission (Energy Commission) PIER-funded Renewable Distributed Generation (RDG) Assessment project provides a sound methodology for utility distribution companies (UDCs) to evaluate the potential of RDG on their systems. With this project, Energy and Environmental Economics, Inc. (E3) and Electrotek Concepts (ETK) have developed methodologies and associated tools that municipal utilities can use to evaluate a wide variety of RDG options for their future resource planning needs. Given that many of the considerations for evaluation of electricity resources (e.g. market prices, fuel prices, technology costs, etc.) continually change, we designed this methodology to be flexible and able to address the very dynamic nature of the electricity industry.

In addition to developing a methodology and transferring the process to the municipal utilities, our team conducted a 3-day RDG Seminar for employees of each utility to provide them with a baseline understanding of the process and to enable them to continue using this evaluation methodology into the future.

In this report, we provide the results from our application of the RDG assessment methodology for one of the four California municipal utilities that participated in the project – Alameda Power & Telecom (Alameda P&T). Each municipal utility had its own interests and goals for participation in this project and therefore, 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.

The RDG evaluation methodology involves two analytical processes that occur simultaneously; an economic analysis and an engineering analysis. Throughout this report, we describe the results from both the economic and engineering analyses for the Alameda P&T RDG assessment. The Alameda P&T RDG assessment, along with the three other participating municipal utilities, provides an example of 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 on-going Energy Commission PIER programs to develop a systematic and state-wide approach to evaluate RDG.

1.1. Background

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

1.1.1. Overview of Analysis

This project was designed to identify the best renewable DG projects from both economic and engineering perspectives. This includes (1) identifying the best locations for RDG in a local Utility Distribution Company (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.

The RDG assessment for each utility is developed in several chapters, each chapter contains a major step in the evaluation. When taken together these chapters contain our team's suggested methodology for RDG planning and evaluation as applied in four specific cases.

1. **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

2. **RDG Engineering Screening Analysis**

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

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, 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.

Reliability Analysis. The reliability analysis chapter contains the impact of RDG on utility reliability using three complimentary methods. These methods are designed to evaluate the non-monetized impacts of RDG on electric reliability.

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

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

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

Uncertainty Analysis. The uncertainty analysis examines the sensitivity of the results and recommendations for cost effective and appropriately sited RDG to varying conditions. This analysis incorporates "high" and "low" range estimates of technical parameters, including market price, transmission costs, distribution costs, RDG capital costs, capacity factor, and fuel costs.

These analyses are interrelated as represented in Figure 2. The shaded areas represent the major analyses and the boxes in each area represent components involved in completing the analyses.

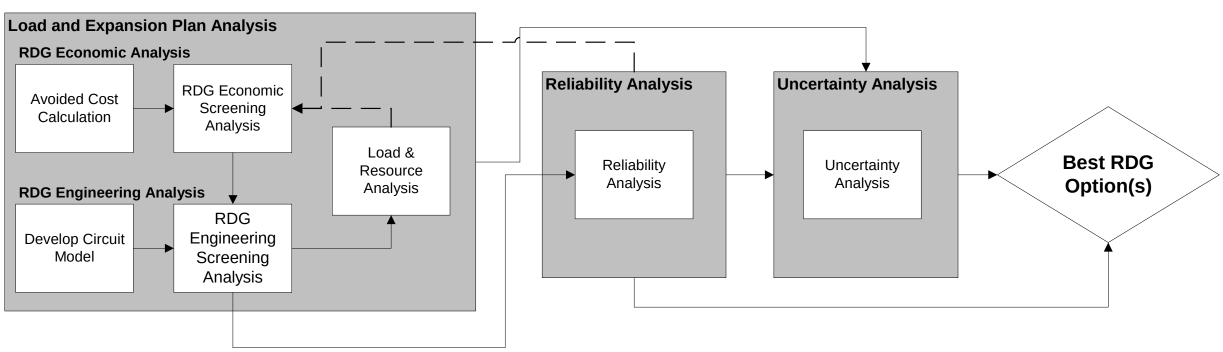

Figure 2: RDG Analysis Process Diagram

The flowchart indicates (dotted-line) that there is a potential feedback loop between the reliability analysis and the economic screening analysis. The normal progression of work is that 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. Based on both the engineering screening and reliability analyses, the economic screening analysis can then be further refined via feedback loops.

Similarly, the overall analysis can be refined through the consideration of uncertainty. 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.'

1.2. Summary of Results for Alameda P&T

The results of our analysis are described in detail in each chapter of the RDG Assessment Report described above and highlights of these results are provided herein.

1.2.1. 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. 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.

Results are summarized in Table 1. Looking at this table, one can quickly see which RDG technologies are cost-effective as well as identify which other technologies may be close to a B/C ratio of 1.0 and warrant further evaluation. The Utility Cost Test (UCT) is calculated assuming the RDG is utility-owned, while the Ratepayer Impact Measure (RIM) is calculated assuming the RDG is owned by the customer.

Table 1: Results of Alameda P&T RDG screening, under base-case assumptions

	TRC Cost Test	Participant (Customer or Merchant)	RIM Test (Customer)	UCT Test (Utility Owned)
Biogas - 10kW PEM Fuel Cell	0.29	0.38	0.55	0.24
Biogas - 10kW PEM Fuel Cell CHP	0.44	0.63	0.50	0.36
Biogas - 100kW SOFC Fuel Cell	0.45	0.58	0.55	0.37
Biogas - 100kW SOFC Fuel Cell CHP	0.62	0.90	0.50	0.50
Biogas - 200kW PAFC Fuel Cell	0.35	0.46	0.55	0.29
Biogas - 200kW PAFC Fuel Cell CHP	0.54	0.78	0.50	0.45
Biogas - 200kW PEM Fuel Cell	0.40	0.52	0.55	0.33
Biogas - 200kW PEM Fuel Cell CHP	0.61	0.88	0.50	0.50
Biogas - 250kW MCFC Fuel Cell	0.33	0.43	0.55	0.28
Biogas - 250kW MCFC Fuel Cell CHP	0.45	0.65	0.50	0.37
Biogas - 30 kW Capstone 330 Microturbine	0.41	0.53	0.55	0.31
Biogas - 30 kW Capstone 330 Microturbine w/ CHP	0.61	0.80	0.55	0.51
Biogas - 500 kW Gas Recip GA-K-500	0.65	0.85	0.55	0.48
Biogas - 800kW Caterpillar G3516 LE	0.75	0.98	0.55	0.55
Biogas - 800kW Caterpillar G3516 LE w/CHP	**1.12**	**1.46**	0.55	0.88
Biogas - 3MW Caterpillar G3616 LE	0.80	**1.04**	0.55	0.59
Biogas - 3MW Caterpillar G3616 LE w/CHP	**1.17**	**1.52**	0.55	0.91
Biogas - 5MW Wartsila 5238 LN	0.84	**1.10**	0.55	0.63
Biogas - 20MW Baseload	0.52	0.38		0.61
Biodiesel - 500kW DE-K-500	1.00	**1.22**	0.57	0.68
Solar - PV-5 kW	0.22	0.20	0.63	0.22
Solar - PV-50 kW	0.29	0.28	0.60	0.29
Solar - PV-100 kW	0.29	0.28	0.60	0.29
Solar - Thermal SAIC SunDish 25 kW	0.19	0.15	0.06	0.32
Wind - Bergey WD -10kW	0.12	0.16	0.51	0.12
Wind - GE 750 kW	0.99	0.99		**1.79**
Wind - GE 1.5 MW	**1.16**	**1.16**		**2.08**

For each of the technologies in Table 1, we conducted uncertainty analysis to determine the sensitivity of results to changes in the underlying assumptions. Figure 3 shows an example: the sensitivity of the TRC test results for the biodiesel 500 kW generator to changes in underlying variables in the form of a "spider diagram." The nucleus of the spider diagram is the Base Case scenario and each "leg of the spider" represents the effects 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.

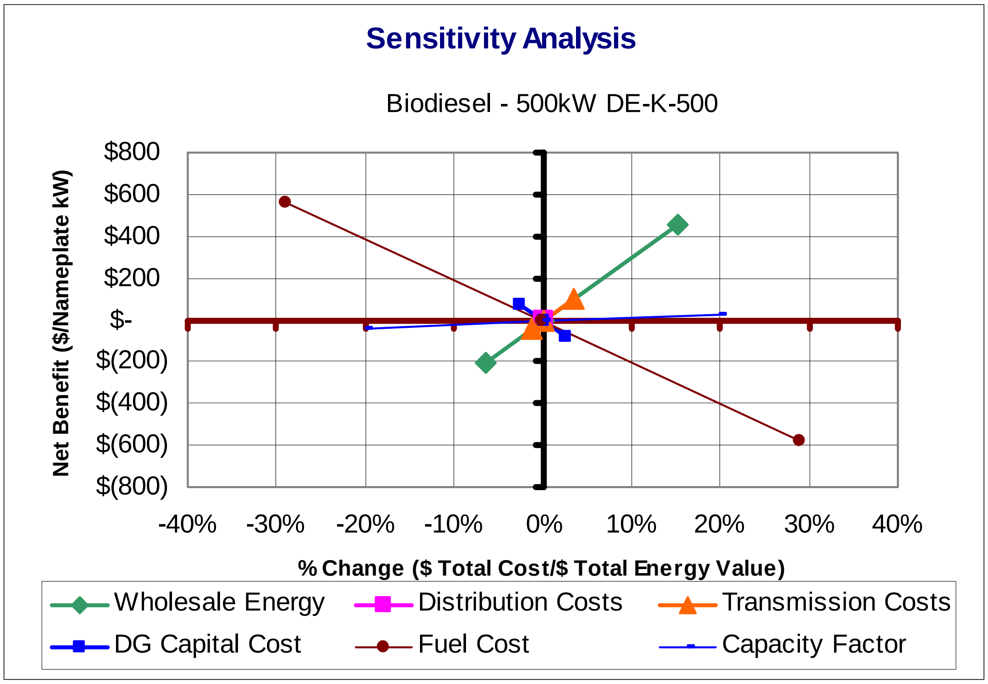

Figure 3: Sensitivity Analysis For 500 Kw Biodiesel Generator, TRC Test

The percentage change along the horizontal access is expressed as the change in the lifecycle value of the variable in question, relative to the change in lifecycle value of the generation output of the unit (rather than expressing the change in each variable relative to itself).

1.2.2. 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 4 shows a typical diagram for the peak load case for Alameda. The thickness of the lines in this plot are in proportion to the power flowing in the lines. Jenney Substation serves an area where much of the new growth is anticipated and correspondingly, one of the more promising areas for new renewable DG applications.

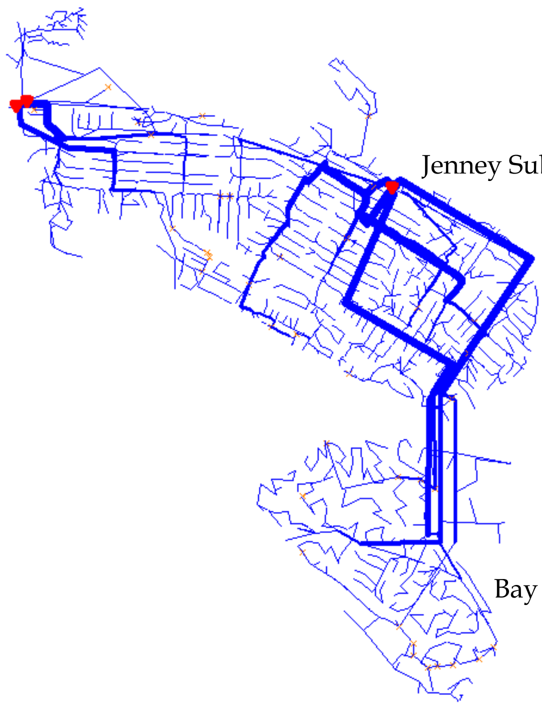

Figure 4: Power Flow In Alameda P&T System

The engineering analysis evaluated line loss for several reference cases, as shown in Table 2 and Table 3. Table 2 shows that each of the RDG measures reduces the line losses on the system, although when delivery losses are included in the analysis of the two options for a 20 MW system on Bay Farm Island, the total energy losses actually increase. Table 3 shows the total energy and demand savings resulting from the reference cases, including the effects of loss savings. The peak loss savings in Table 2 can not be used to calculate the peak demand savings in Table 3, since the two are not necessarily contemporaneous.

Table 2: Loss savings summary for Alameda P&T reference cases

Case	Loss Savings Summary				
	Annual Loss Savings			Peak Loss Savings	
	kWh	%	% of gen kWh	kW	%
2 MW PV	109,115	1.8	3.0	0.0	0.0
8 MW CHP Peaker	916,235	15.4	4.5	246.6	14.6
8 MW CHP BaseLoad	2,615,144	44.0	3.7	560.8	33.2
20 MW Baseload 1	791,268	13.3	0.5	480.1	28.5
20 MW Baseload 2	402,261	6.8	0.2	428.2	25.4
20 MW Baseload 1*	(4,023,714)	-67.7	-2.3	-101.7	-6.0
20 MW Baseload 2*	(1,173,370)	-19.7	-0.7	239.3	14.2

* includes delivery losses for DR

Table 3: Energy and demand savings summary for Alameda P&T reference cases

Case	Energy and Demand Savings Summary				
	Gen MW	Purchase Power Savings		Peak Demand Savings	
		MWh	% of Gen	kW	% of Gen
2 MW PV	2	3,706	103.0	8	0.4
8 MW CHP Peaker	8	21,356	104.5	3,661	45.8
8 MW CHP BaseLoad	8	72,692	103.7	8,567	107.1
20 MW Baseload 1	20	170,773	100.3	19,933	99.7
20 MW Baseload 2	20	174,277	100.2	20,284	101.4
20 MW Baseload 1*	20	171,003	97.6	19,939	99.7
20 MW Baseload 2*	20	173,760	99.2	20,267	101.3

* includes delivery losses for DR

Benefits from RDG to a distribution system are very site specific. 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 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 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. 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.

Figure 5 depicts the results for optimal location of a small generator with regard to reducing peak load losses. The buses in red represent the top 25% of the buses with respect to loss reduction. The buses in green are the next most favorable and blue the least. The cutoff between the blue and green buses is 50%.

Loss improvement varied from 0 to 10% of the generator's capacity (max of 10 kW loss reduction for a 100 kW generator) depending on location. This is typical for a small generator being added at peak load. There is a high marginal improvement for the first small generator with respect to losses – if it is in the right place. Then the improvement declines for other generators added in the same general area.

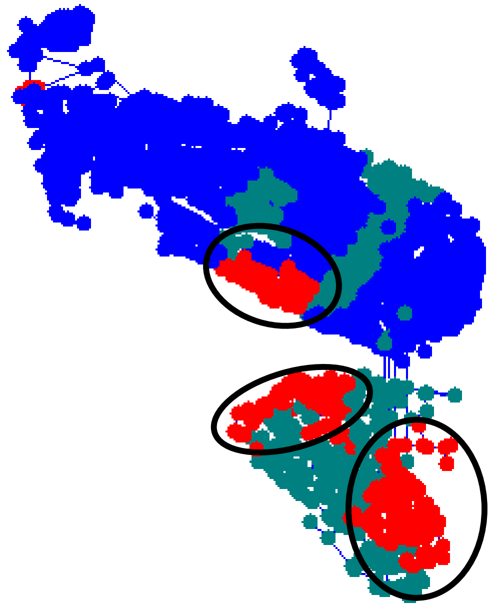

Figure 5: Optimal Locations For Small Generation (100 Kw) On Alameda P&T Systems With Respect To Reducing Peak Load Losses

The previous analysis was repeated for a large generator (5 MW). This is approximately 50% of the capacity of a 12 kV feeder and a generator this large would be expected to actually increase the losses in some locations.

The range of loss reduction at peak load is from 6% of the generator size (30 kW) to a 3% (15 kW) *increase* in losses. Figure 6 shows the optimal locations with respect to losses in red.

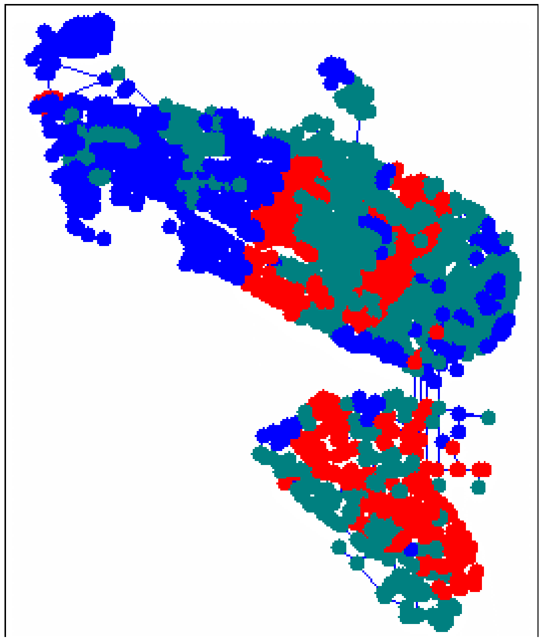

Figure 6: Optimal Locations For A Large RDG (5MW) With Respect To Loss Reduction At Peak Load

For more detailed discussion of the engineering screening results, see the Engineering Analysis on page 39.

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 for Alameda Power & Telecom (Alameda P&T). RDG is deemed cost-effective if it produces positive net benefits:

Net Benefits = Benefits – Costs

The bulk of the benefits associated with RDG in the above equation is comprised of *avoided costs*, which are the described in detail in the section below. As there are many other benefits that may result from RDG installation, such as indirect environmental benefits, a discussion of these components follows.

2.1. Avoided Costs

Avoided costs, aptly named, are the costs that a utility can avoid incurring by taking some action under consideration. As such, avoided costs can be thought of as the benchmark for cost-effectiveness evaluation of Renewable Distributed Generation (RDG) technologies. If the avoided costs (the costs the utility would have incurred in the absence of RDG) are greater than the RDG costs, the RDG technology is cost-effective.

The actual comparison of benefits (avoided costs and other benefits) and costs (installed and operating costs of RDG) are addressed in the Economic Screening section. 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 Alameda P&T's service territory.

This section is organized as follows:

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

2.1.1. General Avoided Cost Methodology

Throughout this analysis, we have drawn on information obtained from Alameda P&T and publicly available data sources to calculate avoided costs within Alameda P&T's service territory. Energy commodity purchases, transmission costs, and infrastructure expansions that can be displaced as a result of the installation of RDG within (or close to) Alameda P&T's service territory make up the bulk of the avoided costs. Solar PV, for example, may reduce the utility's energy purchases from the market, reduce associated transmission costs, and defer load growth that necessitates expansion of the distribution 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.

2.1.2. Generation Avoided Costs

2.1.2.1. 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 allows 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. 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.

The best measure of future market prices is given by forward price quotes. We use broker quotes given to Alameda P&T for the period from 2005 through 2008 as the initial basis of our estimate for avoided generation costs. These price quotes include both on- and off-peak prices.

For 2010 and beyond we use the CEC's gas forecast and Long Run Marginal Costs (LRMC), as described in greater detail below. We use linear interpolation to determine the estimate for 2009. The resulting estimates are for the peak-period only; we use Alameda P&T's historic off-peak to peak ratio of 75% to estimate off-peak prices.

Long Run Marginal Cost (LRMC): 2010 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 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.

Our assumptions regarding CCGT operating cost and performance were obtained from a CEC August 2003 staff report.[1] A key driver of CCGT cost is, of course, the cost of gas. As NYMEX natural gas futures are available only through 2009, we use the CEC's gas forecast.

2.1.2.2. Generation Avoided Cost Results

Table 4 shows the first 10 years of generation avoided cost inputs in our 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. Note that these values change continuously in response to changing market conditions, but these values can be easily updated in the model to reflect the latest information.

Table 4: Screening Model Generation Avoided Cost Inputs As Of March 31, 2004

Wholesale Energy Forecast (Nominal $/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak	$55.75	$55.75	$56.25	$56.25	$59.13	$62.02	$64.15	$66.18	$68.56	$70.92
Off-Peak	$41.55	$41.88	$42.57	$43.09	$44.35	$46.51	$48.11	$49.64	$51.42	$53.19

Table 5 shows the definition of the two TOU periods we have used in our analysis, which correspond to the peak and off-peak pricing periods in the forward electricity market quoted by Platts.

Table 5: 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 7 along with the 20-year levelized stream for both the peak and off-peak periods.

1 "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.

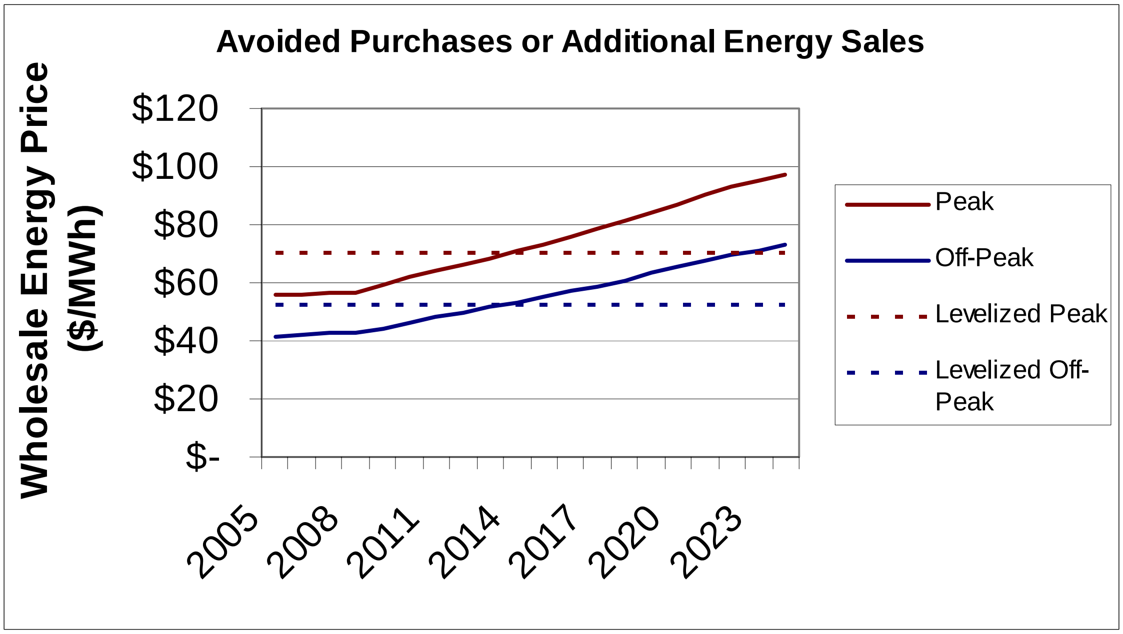

Figure 7: Generation Avoided Costs

All avoided costs are in nominal dollars. The 20-year levelized values in Figure 7 are the level payments required to produce the same total cost as the non-levelized stream, given the utility's discount rate. This value is $70.15/MWh in the peak period and $52.68/MWh in the off-peak period.

We also calculated "high" and "low" price scenarios for avoided generation costs. In our base case forecast, electricity prices for the years 2005 – 2008 are given by Alameda P&T forward price quotes. Since these are forward contracts that Alameda P&T can buy, the forecast represents a fully hedged position. For this reason, we hold the first 4 years of the forecast constant for the base case, high, and low scenarios. For 2010 and beyond, when the forecast is based on the Energy Commission's gas forecast and the cost of production, we use the Energy Comission'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. For 2009, we use linear interpolation, as in the base case.

The base, high, and low avoided generation cost scenarios are shown in Figure 8.

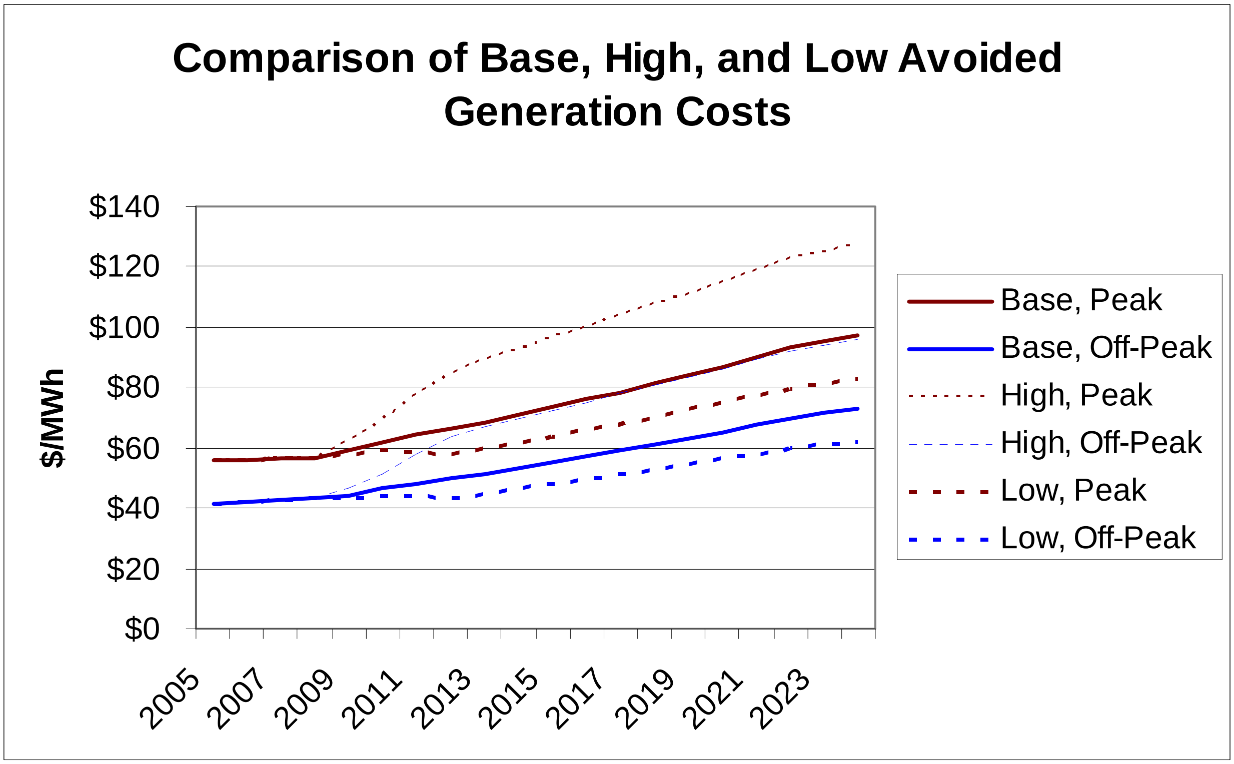

Figure 8: Comparison Of Base, High, And Low Scenarios For Avoided Generation Costs

In the Uncertainty Analysis, described in Chapter 6.0, we discuss the sensitivity of benefit-cost analyses to the high and low scenarios shown above.

2.1.3. Transmission Avoided Costs

2.1.3.1. Transmission Avoided Costs Methodology

Transmission avoided costs, for a municipal distribution utility such Alameda P&T, consist of transmission charges paid to other entities that Alameda P&T will not have to pay with increased in-area generation. 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 RDG.

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 Section 4.1. However, since the municipal distribution utility jurisdiction does not include transmission investments, we simply apply the actual transmission charges paid to import power onto the local distribution system.

2.1.3.2. Transmission Avoided Cost Results

Currently, Alameda P&T's transmission charges are \$7.02/MWh (\$2.22/MWh for high-voltage wheeling, plus \$2.93/MWh for low-voltage wheeling, plus \$1.87/MWh for control area GMC). Alameda P&T resource staff deem it highly unlikely that transmission charges will be reduced in the near future, so this makes up our "low" scenario forecast.

It is expected that transmission rates will rise in the near future and may also include a congestion charge. We use a value \$7.79/MWh for our "base case," reflecting these likely outcomes. [2]

The "high" scenario is subject to greater uncertainty. Under Locational Marginal Pricing (LMP), proposed by the California ISO for implementation in 2004, 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. However, because Alameda - and the Bay Area in general - are characterized by high transmission congestion, the effects of the proposed change could be quite severe. With Alameda P&T's guidance, we have assumed a value of \$10/MWh to reasonably represent an upper bound of transmission costs under a "high" scenario.

More detail on the sensitivity testing is provided in the Uncertainty Analysis Chapter on page 131.

2.1.4. Distribution Avoided Costs

2.1.4.1. Distribution Avoided Costs Methodology

Distribution avoided costs result when peak loads are kept below a level that triggers a distribution investment. Distribution avoided costs are often referred to as the 'deferral value'. 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 avoided cost. We use the Present Worth (PW) method to calculate this value.

Under the PW method, the revenue requirement faced by the utility under the base case plan (no RDG) and the plan with RDG are compared 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, etc.

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2 Per discussions with Alameda P&T staff the base case value of \$7.79/MWh is comprised of several charges including a high-voltage wheeling charge of \$2.32/MWh, a low-voltage wheeling charge of \$3.28, a GMC of \$1.87/MWh, and an anticipated congestion charge of at least \$0.32/MWh

The expression of the PW formula that we use to calculate the distribution avoided cost is shown in Equation 1. Using this equation will result in a $/MW-year value for distribution avoided costs.

Equation 1: The Present Worth Formula

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

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*); and

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 costs values relevant to Alameda P&T The basic model inputs are shown in Table 6.

Table 6: 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.
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.

2.1.4.2. Distribution Avoided Cost Results

Through our data collection efforts, we learned that Alameda P&T has no planned investments at the distribution level. Therefore, there are no distribution costs to avoid and this value will equal zero in our model.

2.2. DG Economic Screening

In this section, we incorporate the results described in the avoided costs section to further develop the renewable distributed generation (RDG) economic analysis. The avoided costs are used to calculate the benefits of RDG; herein we compare those benefits to the costs of RDG to calculate overall cost-effectiveness. We provide a description of the inputs, methodology, and results from our analysis of multiple RDG technologies that could be installed within or nearby Alameda P&T service territory.

The approach we take to evaluating potential RDG involves determining the economic 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:"

- **Participant Cost Test.** Measures the economic impact to the RDG owner.
- **Ratepayer Impact Measure (RIM).** Measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels if a customer installed RDG.
- **Utility Cost Test (UCT).** Measures the change in the amount the utility must collect from the customers every year if the utility owned the RDG.
- **Total Resource Cost Test (TRC).** Measures the net direct economic impact to the community.
- **Societal Cost 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 help 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 7.

Table 7: Questioned addressed by the various cost tests

Participant Cost Test	Is it worth it to the customer to install RDG? Is the customer likely to want to participate in a utility program that promotes RDG?
Ratepayer Impact Measure	What is the impact of the RDG 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 RDG 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 RDG 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 8, 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 8: Benefits and costs of various test perspectives included in our modeling

Tests and Perspective	RDG Costs	RDG 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 RDG Owner**	• RDG capital and operating costs • Siting costs for utility-owned RDG	• Transmission tariff savings • Distribution capacity savings • Voltage support • Energy savings • Other direct benefits
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 • Voltage support • Energy sales and/or savings • Transmission tariff savings • Other direct benefits
Societal Cost Test	• RDG capital and operating costs • Administrative costs	• Distribution capacity savings • Voltage support • Energy sales and/or savings • Other direct benefits • Indirect benefits, such as reduced emissions and increased property value • Transmission tariff savings

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.

2.2.1. Calculation of Costs and Benefits

In this section, we describe our methodology for calculating the benefits and costs that enter into the cost tests described above in greater detail. 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 in this memo on an NPV basis.

2.2.1.1. Costs of RDG

For the Participant, TRC, and Utility as RDG Owner test perspectives, the costs of RDG comprise the capital, fuel, and O&M (fixed and variable) costs of the RDG technology under evaluation. Table 9 shows the key RDG and traditional RDG performance characteristics and cost data we used in our analysis. We used publicly available information on commercially available technologies.

Table 9: Performance Characteristics For RDG Technologies And DG Operating Using Renewable Fuels

Technology Name	Generator Life (Years)	Fuel Type: (1)No Cost (solar, hydro, wind) (2) Biodiesel 80/20 (3) Other Fuel (4) Landfill Gas (5) Renewable Fuel #5	Heat Rate (Net Heat Rate for CHP Applications)	Installed Capital Cost $/kW	Fixed O&M $/kW-yr	Variable O&M $/kWh
Biogas - 10kW PEM Fuel Cell	10	4	12,507	$5,500	$18.00	$0.03
Biogas - 10kW PEM Fuel Cell CHP	10	4	7,007	$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	10,428	$4,500	$6.50	$0.03
Biogas - 200kW PAFC Fuel Cell CHP	10	4	5,346	$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	8,723	$5,000	$5.00	$0.04
Biogas - 250kW MCFC Fuel Cell CHP	10	4	6,303	$5,000	$5.00	$0.04
Biogas - 30 kW Capstone 330 Microturbine	10	4	15,443	$2,201	$0.00	$0.02
Biogas - 30 kW Capstone 330 Microturbine w/ CHI	10	4	5,573	$2,604	$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 - 20MW Baseload	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-5 kW	20	1	-	$8,650	$14.30	$0.00
Solar - PV-50 kW	20	1	-	$6,675	$5.00	$0.00
Solar - PV-100 kW	20	1	-	$6,675	$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

** Additional information on RDG technologies is available in Appendix A.*

For the RIM test, RDG capital and operating costs are excluded since these costs are born 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 RDG program.

2.2.1.2. Generation Energy Benefits

The energy generated by RDG is valued at the wholesale level for the utility, merchant plant, and social perspectives, and at the retail, or bill savings, level for participants who install DG on site, as shown in Table 10.

Table 10: Generation benefits by test perspective

Value Basis	Calculation	Participant Test	RIM Test	TRC Test	UCT (Utility owned RDG)
Wholesale	Market prices * DG output * Line Loss	Benefit (merchant plant)	Benefit	Benefit	Benefit
Retail	Rates * DG output	Benefit (behind the meter installation)	Cost	Transfer	N/A

When evaluating the wholesale value of energy, we use the forecast of market electricity prices described in the avoided generation cost section. Market prices are the appropriate measure of avoided costs from the utility's perspective because when the utility is short, RDG allows the utility to save the money it would have spent on market purchases and when the utility is long, RDG allows the utility to increase sales of excess energy into the market.[3] Market prices are also the appropriate measure of benefits from the merchant plant perspective because they represent the value that can be obtained by selling power into the market.

For behind the meter installations, the benefit to the customer is the reduction in utility bills. We multiply RDG output by rates to compute customer bill savings. From the RIM test perspective, rates multiplied by RDG output are considered a cost, as this is the revenue loss to the utility.

We have designed our analysis to calculate bill reductions and revenue loss based on marginal rates that reflect the change in the bill when RDG is operational. In practice, marginal rates are often not available or are difficult to calculate for the "average" customer. This is particularly true if "block" rates are in place.

For simple energy rates, there is no difference between the average and marginal rates. In other cases, some additional accuracy could be gained by calculating the revenue and bill effects based on marginal rates. To evaluate rates that include demand charges, significant customer charges, and other non-bypassable components, we have the capability to designate a portion of the rate as non-bypassable.

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3 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%.

2.2.1.3. Transmission Benefits

Transmission avoided costs for a municipal distribution utility are based on transmission charges paid to the transmission owners. Our analysis allows different scenarios of transmission pricing to be modeled.

Transmission savings are applied only when the RDG interconnection point is on the municipal utility system (i.e. at the customer or secondary distribution level). Interconnections on the transmission system at the primary or bulk transmission level do not result in any reductions in transmission fees.

The RDG output is increased by line losses to the utility interconnection point to calculate the total value of transmission savings, since the larger amount of energy would need to be transmitted in order to produce the RDG output level of energy at the end-use. Since line losses may vary by TOU period, this calculation is performed by TOU period.

2.2.1.4. Distribution Capacity Benefits

Distribution capacity savings are achieved when a distribution capacity investment project is delayed as a result of capacity benefits from sufficient RDG interconnecting with the electrical system. Distribution capacity savings are only applied in cases where the RDG interconnection point is at the customer or on the secondary distribution system and the RDG can defer a planned distribution investment. When RDG interconnects at the primary or bulk transmission level, no avoided distribution capacity costs can be realized on the distribution system because the RDG has no effect on the planned distribution investment.

To arrive at an annual value for distribution capacity savings, we use the Present Worth (PW) method. Under this approach, we calculate the change in the net present value of the revenue requirement divided by the peak load reduction required to achieve a deferral. For example, a 2 MW RDG installation that deferred an investment for 1 year, thus saving $100K, would be valued at $50/kW-year. More detailed discussion of distribution avoided costs is provided in the Distribution Avoided Cost Section beginning on page 19.

Even though we compute a marginal cost, we recognize that distribution capacity savings are "lumpy," in that investments are only deferred if RDG can provide the total capacity needed to keep the system within its reliability criteria. For example, if 10 MW of capacity are required on a system to defer an investment, nine 1 MW RDG units will not provide enough capacity to defer the original distribution investment. If one more incremental unit of RDG were added, thus meeting the system requirements, the entire distribution capacity savings from an investment deferral could be attributed to the RDG project. This would be one "lump" in the calculation of distribution capacity savings.

We handle this lumpiness with a two-step process. In the first step, we "smooth out" the lumpiness by calculating the marginal distribution capacity value of the RDG installation *if sized to exactly match the amount required for deferral*. In the second step, we loop back based on the results of the engineering model and the resources expected to be installed. Based on this information, we adjust the distribution marginal costs to reflect the actual deferral that could be expected given an estimate of coincident peak load reduction.

Key Drivers of Distribution Deferral Value

The key drivers of deferral value include the following:

- Expected load growth, which drives the need for new capacity, but also causes such capacity to be used (fast load growth reduces the time new capacity can be deferred)
- Cost of deferrable planned investments
- Ability to locate RDG in a helpful spot and operate it reliably during the local distribution system peak

Identifying High Distribution Capacity Value

The ideal distribution planning area for RDG is usually one with a moderate level of load growth. In such an area, it may be possible to defer the investment for several years with a relatively small on-peak capacity load reduction. If the load growth is very low, then the expansion plan or capacity investment is not likely to be very high. In this situation, the area load growth could potentially be accommodated through switching or other system reconfigurations.

Contrary to popular belief, the area with the most concentrated utility investment is not necessarily the area with the highest value. These areas have high costs for potential deferral, but they usually also have very high load growth. Fast growth makes it difficult to defer capacity expansion for very long, or requires large peak load reductions to do so. Therefore, the value of reducing load per kW of installed RDG is not necessarily high even though there are more dollars at stake.

Realizing Deferral Benefits

In order for a utility to defer a distribution investment, the distribution engineer must be confident that the RDG installation will not result in a reduction in service quality compared to the planned system upgrade. Generally, this means that at least one of the following must apply:

1. RDG must have reliability at least as good as the conventional wires solution; or
2. RDG must meet the same minimum reliability standards as the conventional wires solution.

This seemingly subtle difference can have a large impact on the RDG alternative's cost effectiveness when considering the discrete nature of system failures. A wires solution may result in 99.99% availability in order to meet a minimum standard of 99.9%, because the next best solution may only be 99.8%. There are very large cost and performance differences for the RDG system in meeting a 99.99% versus 99.9% target. This leap in required availability could easily make a RDG system too expensive an alternative.

2.2.1.5. Reliability Benefits

Electric reliability is a measure of the electric system's ability to deliver uninterrupted power within specified power quality tolerances. Reliability benefits of RDG occur when the installed RDG increases the reliability of the distribution system or prevents load shedding due to transmission or system capacity constraints. For example, in the case of Alameda P&T, prevention of transmission line overload is considered a reliability benefit that could result from RDG. There are several methods of quantifying reliability benefits and in our analysis, we quantify reliability benefits using estimates of Value of Service (VOS) and Expected Unserved Energy (EUE).

We compute a weighted VOS based on the proportion of each customer class served on the feeder or system affected by the RDG, and the per kWh VOS for each customer class. The VOS estimates are derived from studies that query customers on how much they would be willing to pay to avoid an outage. The per kWh VOS values are much higher than electricity rates; generally in the range of $5 to $30 dollars per kWh.

The change in EUE is calculated in the engineering analysis, as described in the Reliability Analysis Chapter. We allow a 10-year horizon for the change in EUE, as this is generally the longest term over which utility reliability planning occurs. The reduction in EUE is multiplied by the VOS to arrive at an annual dollar value for reliability benefits.

2.2.1.6. Other Direct Benefits

Other direct benefits we compute include:

- Community Direct Benefits
- Utility Direct Benefits
- RDG Customer Direct Benefits
- Merchant Plant Owner Direct Benefits
- Non-Municipal Incentives

The first four items act as placeholders for any measurable direct impacts of RDG not captured in other parts of the analysis. Inclusion of these items makes the analysis more flexible, since any additional value streams that are identified can easily be added. We model these additional benefits on a *$/kWh produced* value. Any other identified benefits should be calculated in the same fashion.

Non-municipal incentives are participation incentives not paid by the municipal utility, such as Federal tax refunds or state rebates. They are included as a benefit in the Participant Cost Test, as they make DG more attractive to participants. Incentives are also included as a benefit in the TRC test, which measures the effect on the community as a whole.

2.2.1.7. Indirect Benefits of Renewable DG

The benefit/cost analysis described above considers the quantifiable financial benefits and costs of RDG. There are also other RDG benefits, such as reduced environmental degradation, that are much more difficult to measure. While it may be possible to estimate dollar values for some of these elements – emissions, for example, have quantifiable costs in terms of permitting or health remediation – the applicability of these elements to a particular RDG technology, the importance of the elements to a particular municipality, and the dollar or non-dollar value assigned to the elements are largely a judgment call. We therefore offer Figure 9 as an aid in identifying the major indirect value streams that might be considered in accounting for the total value of RDG.

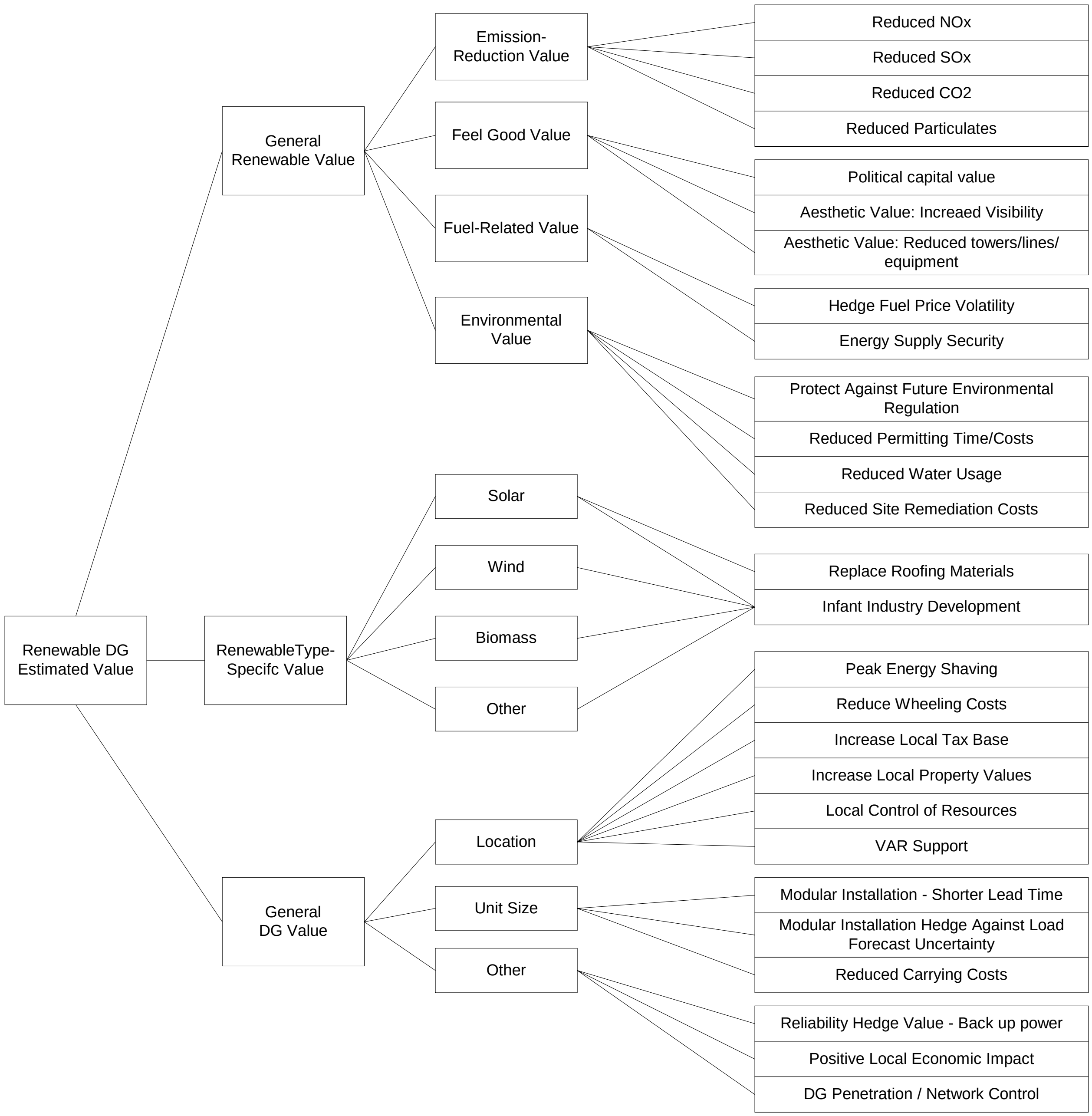


Figure 9: Potential Indirect Benefits Of RDG Installation

While NOx and particulate costs are assumed to be embedded in the market prices that make up the early years of our avoided cost forecast, they are not part of the Long-Run Marginal Costs (LRMC) that make up the latter years of the forecast and therefore would need to be added in as indirect benefits.

As mentioned above, the elements in Figure 9 may be weighed against the results of the benefit/cost analysis to help guide decision-making. For example, if the benefit-cost analysis results in greater costs than benefits for a particular type of RDG being evaluated, decision makers may wish to consider whether the indirect benefits close the gap.

2.2.2. Results of Economic Screening Analysis

We calculated the cost-effectiveness of each of the RDG alternatives according to the methodology described above. We compared lifecycle benefits and costs for each of the applicable tests on an NPV basis. A 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.

Results are summarized in Table 11. Looking at this table, one can quickly see which RDG technologies are cost-effective as well as identify which other technologies may be close to a benefit/cost ratio of 1.0 and warrant further evaluation. The Utility Cost Test (UCT) is calculated assuming the RDG is utility-owned, while the Ratepayer Impact Measure (RIM) is calculated assuming the RDG is owned by the customer.

Table 11: Results of Alameda P&T RDG screening, under base-case assumptions

	TRC Cost Test	Participant (Customer or Merchant)	RIM Test (Customer)	UCT Test (Utility Owned)
Biogas - 10kW PEM Fuel Cell	0.29	0.38	0.55	0.24
Biogas - 10kW PEM Fuel Cell CHP	0.44	0.63	0.50	0.36
Biogas - 100kW SOFC Fuel Cell	0.45	0.58	0.55	0.37
Biogas - 100kW SOFC Fuel Cell CHP	0.62	0.90	0.50	0.50
Biogas - 200kW PAFC Fuel Cell	0.35	0.46	0.55	0.29
Biogas - 200kW PAFC Fuel Cell CHP	0.54	0.78	0.50	0.45
Biogas - 200kW PEM Fuel Cell	0.40	0.52	0.55	0.33
Biogas - 200kW PEM Fuel Cell CHP	0.61	0.88	0.50	0.50
Biogas - 250kW MCFC Fuel Cell	0.33	0.43	0.55	0.28
Biogas - 250kW MCFC Fuel Cell CHP	0.45	0.65	0.50	0.37
Biogas - 30 kW Capstone 330 Microturbine	0.41	0.53	0.55	0.31
Biogas - 30 kW Capstone 330 Microturbine w/ CHP	0.61	0.80	0.55	0.51
Biogas - 500 kW Gas Recip GA-K-500	0.65	0.85	0.55	0.48
Biogas - 800kW Caterpillar G3516 LE	0.75	0.98	0.55	0.55
Biogas - 800kW Caterpillar G3516 LE w/CHP	**1.12**	**1.46**	0.55	0.88
Biogas - 3MW Caterpillar G3616 LE	0.80	**1.04**	0.55	0.59
Biogas - 3MW Caterpillar G3616 LE w/CHP	**1.17**	**1.52**	0.55	0.91
Biogas - 5MW Wartsila 5238 LN	0.84	**1.10**	0.55	0.63
Biogas - 20MW Baseload	0.52	0.38		0.61
Biodiesel - 500kW DE-K-500	1.00	**1.22**	0.57	0.68
Solar - PV-5 kW	0.22	0.20	0.63	0.22
Solar - PV-50 kW	0.29	0.28	0.60	0.29
Solar - PV-100 kW	0.29	0.28	0.60	0.29
Solar - Thermal SAIC SunDish 25 kW	0.19	0.15	0.06	0.32
Wind - Bergey WD -10kW	0.12	0.16	0.51	0.12
Wind - GE 750 kW	0.99	0.99		**1.79**
Wind - GE 1.5 MW	**1.16**	**1.16**		**2.08**

These screening results were calculated using base-case assumptions. Sensitivity of the results to varying input assumptions is discussed in the Uncertainty Analysis Chapter beginning on page 131.

A closer look at selected results is presented in the figures below. The net benefit in these charts may be positive (green) or negative (red) depending on whether benefits exceed costs or vice versa. Figure 10 shows that the 500 kW biodiesel RDG is cost-effective from the TRC and Participant perspectives, but not cost-effective from the RIM and Utility test perspectives.

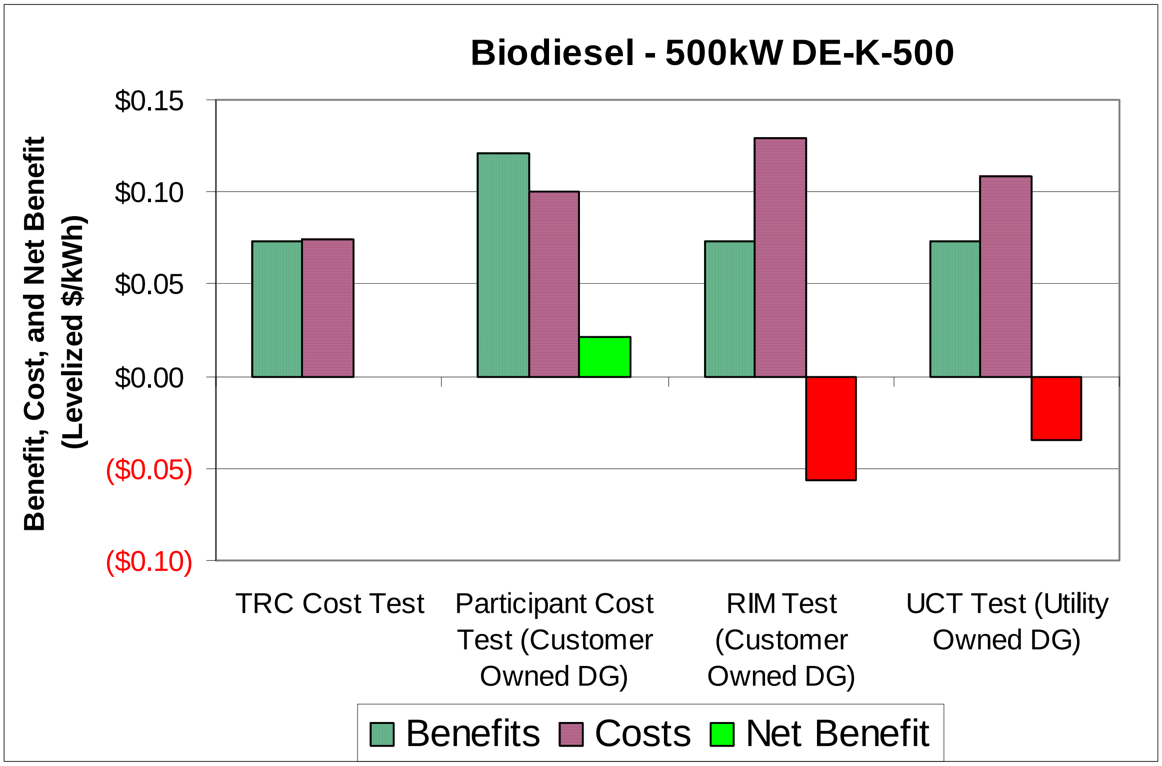


Figure 10: Cost Test Results For 500 Kw Biodiesel RDG

The biodiesel unit is cost-effective from the participant's point of view because it results in large bill savings with relatively low capital and fuel costs. Benefits total $0.12/kWh. Costs total $0.10/kWh, resulting in a savings of $0.02/kWh. The benefit cost ratio is thus 0.12/0.10, or 1.2, indicating cost-effectiveness.

Compared to the Participant Test, the UCT Test has slightly higher costs and smaller benefits. The higher costs are due to discount rates: since the customer discount rate is higher, fuel costs in the out years have a smaller impact on customer economics than on utility economics. The lower benefits occur because the benefits for the customer, which are based on rates, are greater than the benefits for the utility, which are based on generation and transmission costs. Together, these factors result in a B/C ratio for the UCT Test of 0.68.

From the RIM test perspective, the savings in avoided generation and transmission costs resulting from 500 kW biodiesel do not make-up for the lost revenue in reduced rates, resulting in B/C ratio of only 0.57.

Looking at the TRC perspective, which is essentially the summation of the Participant and RIM perspectives, the technology is very nearly break-even, with a B/C ratio of just under 1.0.

Another example is shown in Figure 11 which displays the test results for 50 kW solar PV. This particular technology is not cost-effective from any of the four test perspectives. The primary driver of this result for the TRC, Participant, and Utility tests is the high capital cost of solar PV.

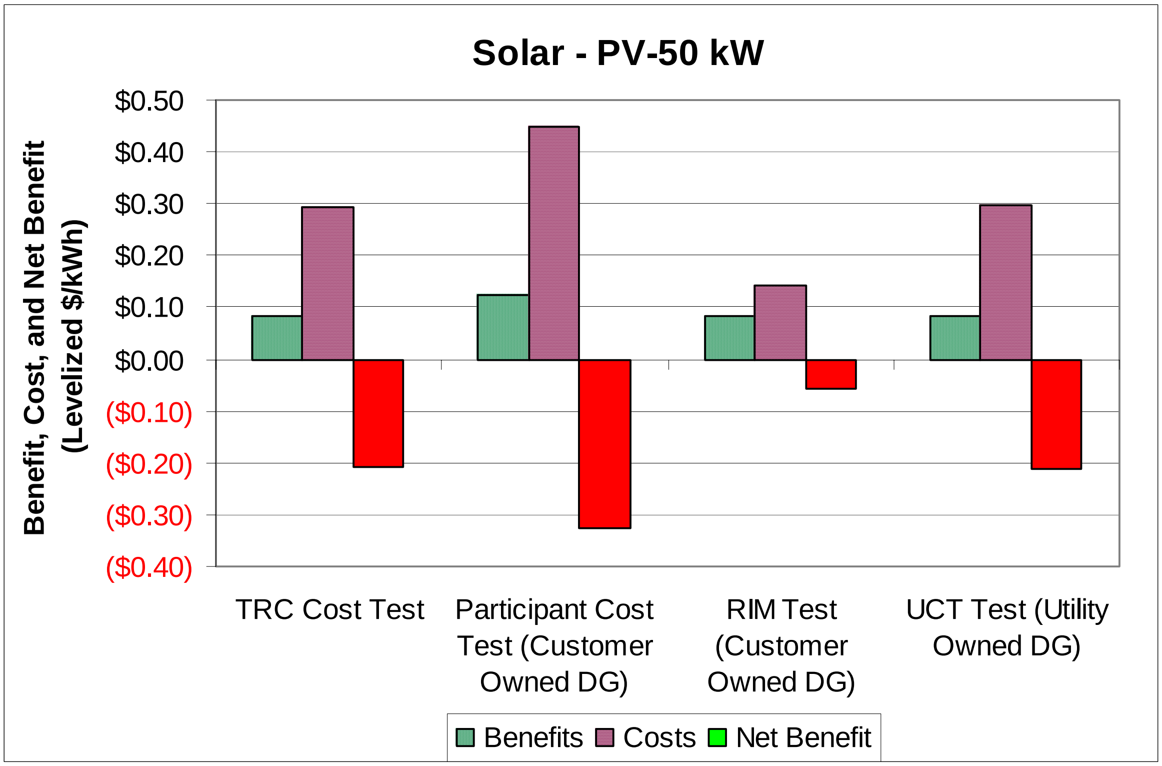


Figure 11: Cost Test Results For 50 Kw Solar PV

For the RIM test, capital costs are not an issue because they are a cost attributed to the participant perspective and do not enter into the RIM test. The RIM test has a B/C ratio less than 1.0 however because, as in the previous example, the reduced revenues from the lower customer bills are greater than avoided costs. In fact, when there are no avoided distribution costs, as is the case here, the RIM test will usually result in a B/C ratio of less than one because customer rates are typically greater than generation and transmission costs.

The results in Figure 12 mirror those in Figure 11. Like solar PV, the small wind unit has very high capital costs relative to the amount of energy produced which results in B/C ratios less than 1.0.

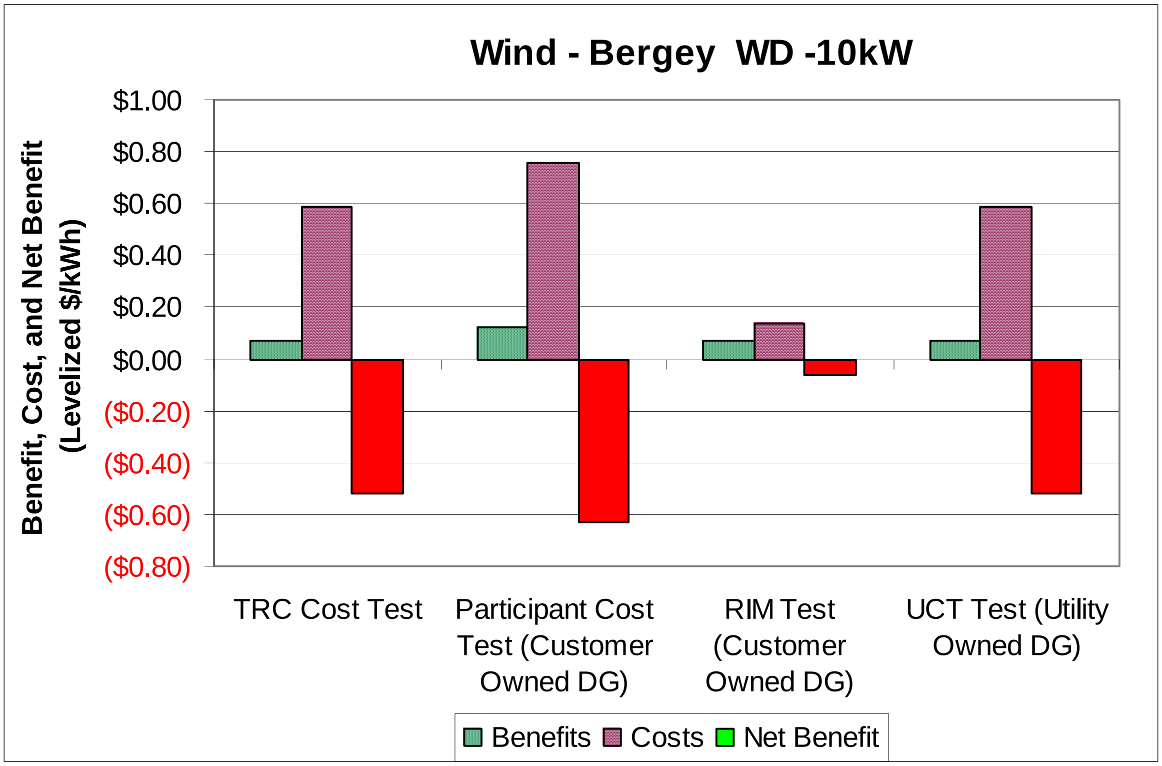


Figure 12: Cost Test Results For 10 Kw Wind Generator

In contrast, a 1.5 MW, large-scale wind unit has capital costs that compare much more favorably to the amount of energy produced. While this is not technically a local RDG project, this technology is an example of a renewable technology that is cost-effective and so it is shown for illustrative purposes. Figure 13 shows cost test results for a 1.5 MW wind unit, which is cost-effective from every perspective evaluated. The RIM test does not apply to this large wind generator because the interconnection point with the grid is assumed to be at the bulk transmission level, meaning that the option is evaluated as alternative source of traditional generation, rather than distributed generation. Benefits far exceed costs in the UCT because the utility enjoys high savings relative to costs, without any reduction in rates.

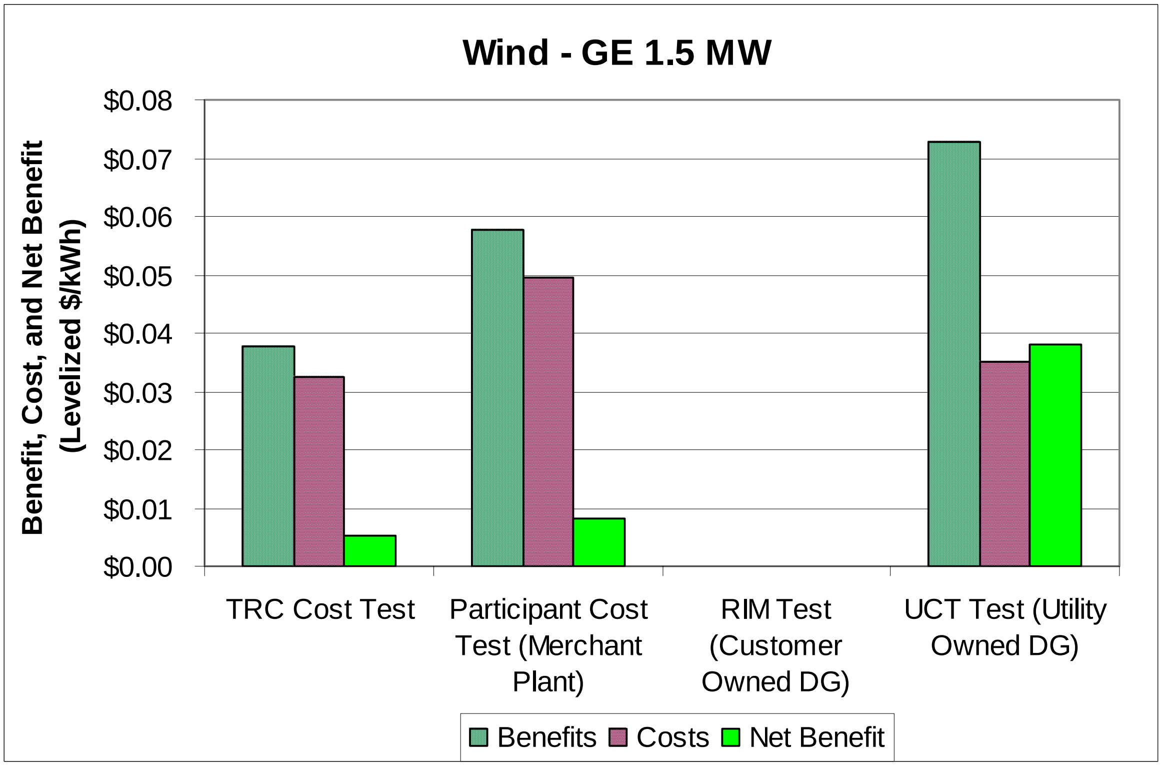


Figure 13: Test Results For 1.5 MW Wind Generator (Assuming 30% Capacity Factor)

2.3. Applying the RDG Screening Results

How might these results guide decision-making at a municipal utility? Clearly if a measure passes all the economic screening tests, as did the 1.5 MW wind generator, it is an excellent candidate for action – assuming a suitable installation site can be found. A 1.5 MW wind turbine is not considered a truly distributed technology in this analysis because if a suitable site were located in Alameda, this would represent a cost-effective renewable solution. Similarly, a true RDG measure that passes all tests, which is possible if there are positive distribution avoided costs, should also be installed. But what about measures that pass some tests but not others?

If a technology passes some screening tests but not others, the decision comes down to a judgment call based on utility priorities. Considerations might include other projects that Alameda P&T could pursue with the required project funding, high cost projects on the horizon, expected future costs of energy, rate levels, and many others. The questions answered by each cost test perspective may help characterize the results to a broader audience in terms of operating margin, rates, expected participation, and overall community benefit.

The biodiesel unit in Figure 10, for example, comes very close to passing the Total Resources Cost test, where the levelized shortfall is less than one-tenth of one cent per kWh per year. When the indirect benefits as shown in Figure 9 are taken into consideration, a case might be made that the total benefits of reduced particulate emissions and increased local control of generation for the community are greater than the slightly higher costs. Even so, should the utility push for its installation when its direct effect will be to increase rates, and hence bills for all customers other than the owner? This is a policy decision that ultimately comes down to the goals and priorities of the utility and other stakeholders. Our goal, in providing multiple test perspectives, is to equip decision makers with the proper tools to understand the trade-offs and ultimately make the best decision for their needs.

3.0 Engineering Screening Analysis

3.1. Overview

This Chapter describes engineering screens performed on the Alameda P&T 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 was given to renewable technologies.

The existing Alameda P&T system has ample capacity for the present peak load of nearly 70 MW. The system is relatively compact with the exception of the feed to Bay Farm Island, which is electrically twice as far from a substation as most of the rest of the system. Much of new load growth is expected to come from Bay Farm Island. The system can withstand a major substation outage based on transformer capacity alone. However, it may not be possible to deliver adequate power to the extremities because of distribution constraints. This is one problem that might be addressed by distributed resources.

The benchmark generation proposal is a 20MW baseload plant powered by a renewable fuel and located on or near Bay Farm Island. This will supply present and future needs on the Island and supply some of the load off Jenney Substation. The particular technology is somewhat irrelevant as long as it is capable of being dispatchable. The plant could be connected into the existing PG&E transmission system or directly to the distribution circuits on Bay Farm Island. Only the latter is evaluated here because connecting to the transmission system does not change the existing system characteristics. The intent of this analysis is to identify potential benefits to the distribution system.

The proposed plant interconnection to Bay Farm Island appears technically feasible. Two interconnection options were considered: two 12 kV cables and a 35 kV option. The 35 kV delivery system has some advantages over a 12 kV system, but the difference is relatively small with respect to the overall savings achieved in purchased energy. The decision on which to build will likely rest on other factors although the loss savings are not insignificant over the life of the system.

Both options will require overcurrent protective relaying that is somewhat atypical for radial distribution systems in order to directly connect into the existing 12 kV feeders on Bay Farm Island. However, it is technically feasible. The 35 kV option with four step down transformers appears to offer some advantages because the transformer impedances provide a buffer between the subfeeders on Bay Farm Island. The fault currents become substantially higher on parts of Bay Farm Island and present overcurrent coordination will have to be reevaluated.

Voltage regulation issues appear minimal. It is possible that the tap changer in the Jenney 2 substation will have to be adjusted downward to account for overvoltages that might occur when the generation comes on line. The tap changers would have to revert to present setting should the generation become unavailable at peak load. Therefore, communications between the proposed plant and existing controls will likely be required to accomplish this automatically.

The 20 MW baseload option is compared to two reference cases: 8 MW of generation sited specifically to minimize losses and 2 MW of solar PV generation uniformly distributed throughout the system. The voltage regulation screen indicates that Alameda P&T system should accommodate approximately 30 MW of uniformly distributed RDG without significant changes. In terms of the percentage of capacity, this is toward the high end expected for a typical 12 kV system due to the compactness of the system. If the generation is concentrated in specific locations, it can be expected that it will take less generation to force changes in the operating procedures and equipment settings. Each case should be evaluated separately. The proposed baseload plant will require alterations to the overcurrent protection scheme and to the voltage regulation scheme.

Graphical screens of the power flows and annual load characteristics reveal areas where distributed generation is likely to have a beneficial impact on the existing distribution system. Beneficial generation must be able to produce power in the early evening hours in winter months because Alameda P&T is a winter peaking utility. This casts doubt on the benefits of solar PV technologies to the power delivery system unless coupled with significant storage. Applications of RDG on Bay Farm Island would appear to offer the greatest potential benefit due to the distance of that load from the substation. Most of the areas on the main part of Alameda have similar potential benefits, with some of the bayside commercial areas on the opposite side of the island from the Jenney substation have potential benefits similar to Bay Farm Island locations.

3.2. Description of Analysis

This report describes the work performed to gain an understanding of the essential electrical characteristics of the Alameda P&T system and to evaluate the feasibility of proposed distributed resource (RDG) alternatives from an engineering perspective. Prior to this analysis, a model of the primary distribution system has been constructed in Electrotek's Distribution System Simulator (DSS). This tool is used to perform the analysis described herein.

The steps in this analysis are:

1. Generate graphics of the power flow to rapidly gain an understanding of the system and begin to understand where there might be some opportunities for RDG.
2. Perform a siting analysis for various sizes of generation to determine where the most benefits to the system can be obtained,
3. Evaluate proposed distributed generator schemes for operational feasibility with respect to losses, voltage regulation, and impact on overcurrent protection.

3.3. Power Flow Characteristics

3.3.1. Peak Load Snapshots

Figure 14 shows a typical diagram for the peak load case for Alameda. The thickness of the lines in this plot are in proportion to the power flowing in the lines. Therefore, the main feeders are clearly visible. This helps the engineer understand how things are connected and how the power is distributed. The Cartwright Substation is on the left and the Jenney Substation supplies the feeders to the right. The model contains more detail of the Jenney feeders than the Cartwright feeders. Jenney Substation serves an area where much of the new growth is anticipated and where one of the more promising renewable DG application is proposed to be interconnected to the system.

Several of the feeders served out of Jenney basically follow a rectangular grid pattern along the city streets to the other side of the city. There are many switches in this grid and Alameda P&T could adjust the switches to change the load balance between the feeders and restore power in case of line failure with relative ease compared to other utility systems that are less confined geographically. The feed to Bay Farm Island is an exception. There are two main feeders coming out of the station to a switching point. Then the feeders are split into two subfeeders each for the channel crossing. The Bay Farm Island load is electrically twice as far from the substation as the load on the main island of Alameda. Thus, it is expected that system characteristics with respect to RDG will be fundamentally different between Bay Farm Island and the rest of the system.

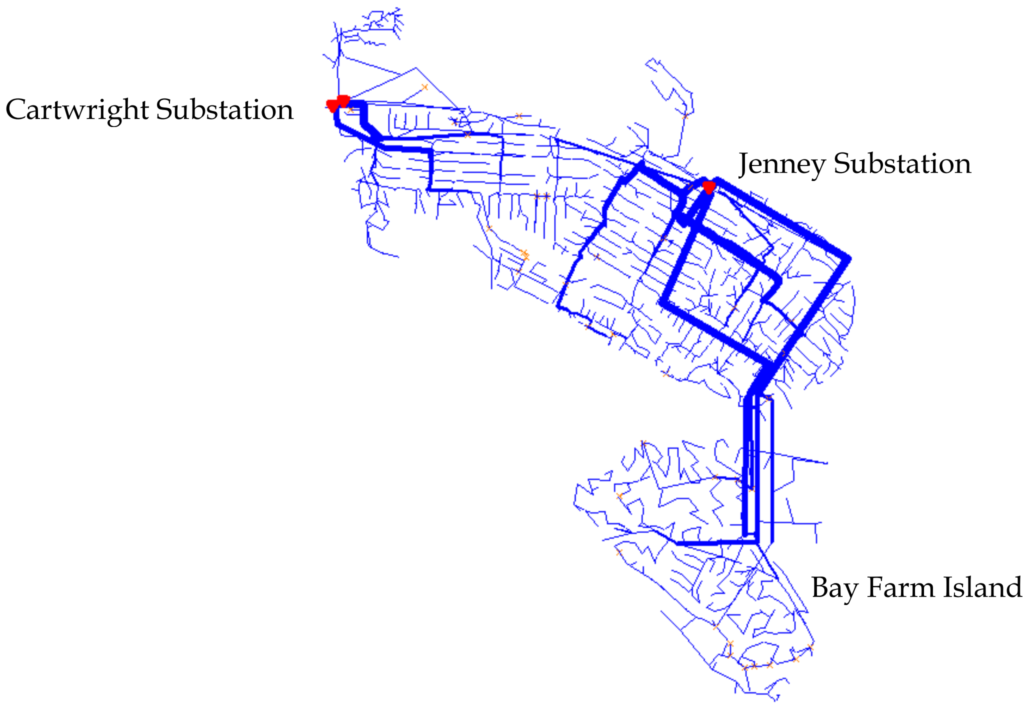


Figure 14: Power Flow in Alameda P&T System

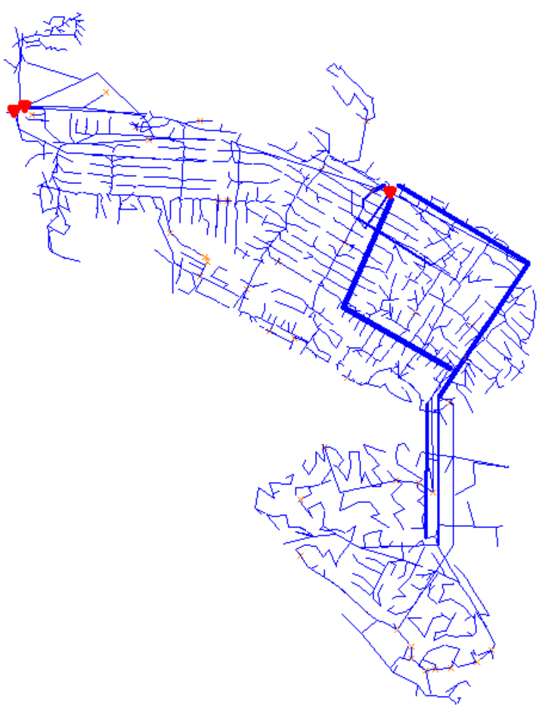


Figure 15: Circuit Plot With Line Section Highlighting Proportional To Losses

Figure 15 highlights the line segments that have the highest losses at peak load. This often gives an indication of where changes may be made that will have the greatest impact on the efficiency of the system. Also, portions of the system supplied by these lines are often the most constrained, which provides insight into capacity issues as well.

This graphic indicates that there isn't much difference between the line segments on the main part of Alameda. However, it clearly draws attention to the feed to Bay Farm Island and, with respect to RDG, it suggests that it could be more likely to make significant gains by reducing loading served from these feeders. This should not be surprising given that most feeders on the main part of Alameda are similar in length while the feed to Bay Farm Island is at least double that length. This will be a recurring theme throughout this report as various types of RDG analyses are performed.

3.3.2. Annual Load Characteristics

The next engineering screen is to run a yearly simulation to get an idea of what kinds of RDG might have the most benefit. Figure 16 shows a 3-D plot of the energy (kWh) consumption by hour of the day for each month. That is, each point on the plot represents the kWh consumed at that hour for the month. This gives a good idea of when generation would have to be available to do the most good.

The characteristic clearly shows a winter peaking characteristic with late afternoon to evening peaks. The rest of the year is fairly flat. This is not surprising given the relatively stable climate that gets somewhat cooler in the winter.

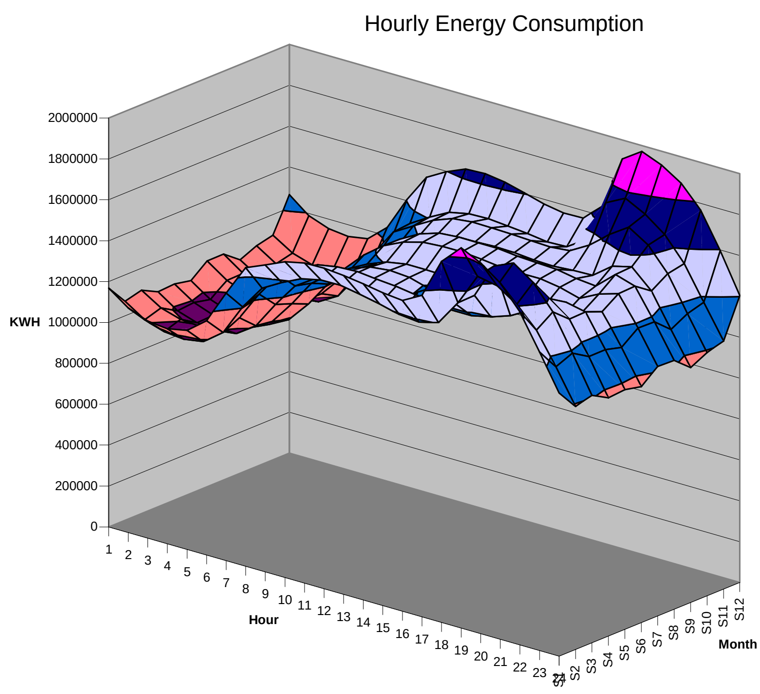


Figure 16: Energy Consumption For Each Hour Of The Day For Each Month

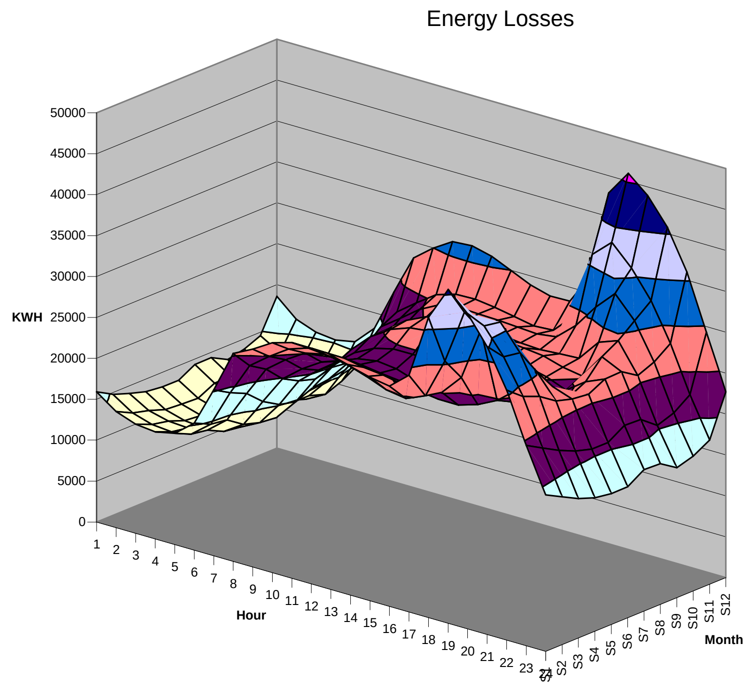


Figure 17: Annual Energy Loss Shape

Another useful plot from the initial annual simulations is developed by making a similar 3-D plot of the kWh losses. Because the losses are a function of the square of the current – and the current increases somewhat disproportionately as the voltage droops under heavy load – the losses are quite nonlinear. Figure 17 highlights the time of year when the system will likely benefit the most from load reduction made possible by RDG.

Finally, a capacity screen is performed. The plot in Figure 18 was generated by setting the Normal ratings of lines to approximately 50% of their maximum ratings. Then the energy exceeding Normal (EEN) is computed, which is an indication of how much capacity in the system is being used. Only lines in which the loading exceeds the Normal rating will contribute to the values shown here.

The value determined for the base case here will be used to compare proposed RDG alternatives in the Reliability Analysis. This will determine how much credit, if any, might be given for relieving capacity in the power delivery system.

The basic idea is that ultimately the reliability of the distribution system is a function of the amount of excess capacity in the normal configuration to allow for restoring the system in the case of the failure of a power delivery element. If no power delivery elements exceed 50% of maximum rating, the utility can be reasonably assured of finding enough capacity in alternate paths to restore the system. Engineers normally plan to be able to serve all the load with one key component out of service without exceeding the maximum ratings of any lines or transformers. A 50% design criterion is conservative, but is actually employed by some utilities which have a strong interest in reliability. It is used here as a benchmark to compare proposed alternatives.

This plot indicates that the Alameda P&T system is not heavily loaded in the normal configuration. The numbers on the vertical axis are relatively small. This means that the Alameda P&T system presently is likely to have sufficient capacity to cover a single contingency.

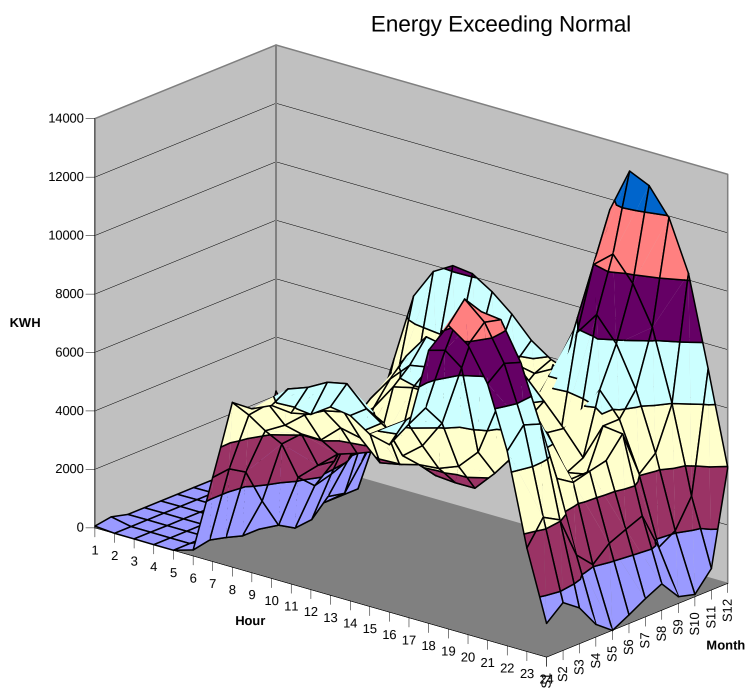


Figure 18: Shape Of Energy Exceeding Normal (Een) Ratings, which is reflective of the capacity of the system

When one speaks of the "capacity" of a complex distribution system, one has to be very careful to define terms. There generally is no single capacity number, but multiple capacities throughout the system, any one of which might be violated. The EEN is an index value that represents a composite of all these capacities. From this, we can derive a total system capacity that reflects each of the various capacity constraints to some degree.

It is not necessarily the absolute value of EEN that are of the most interest in this analysis. It is the difference made by a proposed addition. This becomes one of the key quantities for determining the potential value of a RDG application. Also, the shape is critical. To have a significant impact on distribution reliability, the proposed RDG application must be able to supply power at times that will reduce the exposure to contingencies that could not be covered promptly.

The shape of the curve suggests that the Alameda P&T system is at the greatest risk of not being able to cover a contingency with a quick simple load transfer is in the evening winter hours. Perhaps, this is the only time of the year that there is a significant reliability risk where outage times might be longer than desirable. Failures at other times of the year would seem to have significantly lower risk. This is the kind of result one might expect from a system that has relatively short lines and many switching options.

3.4. RDG Siting Analysis

The preceding analysis gives insight into what types of generation might be useful and what time of day they would need to be operating to provide benefits. However, it doesn't give much indication where the generation should be sited for optimal benefits. Benefits from RDG to a distribution system are very site specific.

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 CHP applications. The locations identifies for larger sizes would be possible candidates for peaking units and large CHP applications.

For each unit size, we typically find optimal sets of locations with respect to losses and EEN. Other criteria are added in special cases. 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 those feeders that are presently utilizing the greatest percentage of their capacity.

In this study, a 100 kW test generator was used for the small unit size 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. 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. Small (100 kW) Test Generator

The first screen is to place the test generator at each bus and then rank the results based on relieving losses in the distribution system. It should be noted that this result depends on the specific loading assumptions in the model. Alameda P&T could hypothetically vary the loading relatively easily by changing the switches so that the optimal locations might very well shift to another feeder.

Figure 19 depicts the results of this analysis. The buses in red represent the top 25% of the buses with respect to loss reduction. The buses in green are the next most favorable and blue the least. The cutoff between the blue and green buses is 50%.

Most areas on the main part of Alameda are roughly equivalent with respect to losses and in the lower 50%. The exception is the area along the waterfront noted in red. There are apparently a number of commercial loads in that area and the area is somewhat remote from the substation, although the distance is shorter than the feed to Bay Farm Island. Therefore, it makes sense that achieving load reduction in these areas would have a significant impact on losses.

Loss improvement varied from 0 to 10% of the generator's capacity (max of 10 kW loss reduction for a 100 kW generator) depending on location. This is typical for a small generator being added at peak load. There is a high marginal improvement for the first small generator with respect to losses – if it is in the right place. Then the improvement declines for other generators added in the same general area.

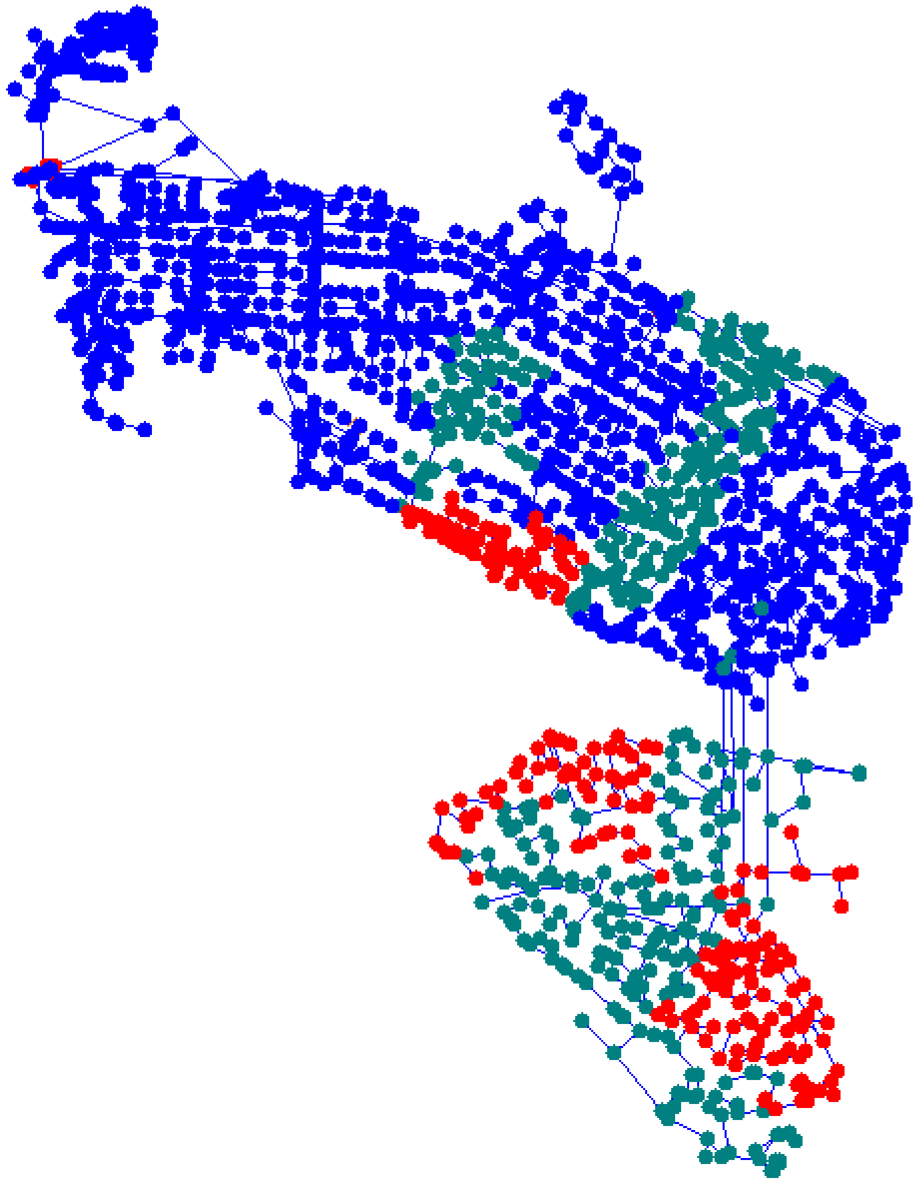


Figure 19: Optimal Locations For Small Generation (100 Kw) On Alameda P&T Systems With Respect To Reducing Peak Load Losses

For the rest of the report, we will use a compressed view of this plot (See Figure 20). This forces the dots representing the buses to overlap, giving a graphic in which the colors run together. This enables a fast qualitative analysis of the results.

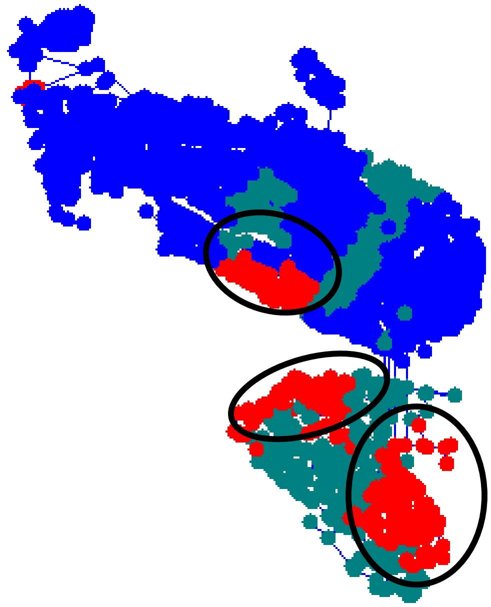


Figure 20: Compressed View Of Previous Figure. Subsequent Graphics In This Report Are Presented In This Format.

This graphic indicates that the areas most likely to benefit from small widely dispersed generation are two feeders on the main part of Alameda and the entire Bay Farm Island. The two areas on Bay Farm Island highlighted in red are those served by the two most heavily loaded feeders, which is not surprising.

The areas indicated are those where load reduction would have the greatest benefit to system efficiency with some possible some benefit to capacity. Figure 21 is a similar plot the degree to which the test generation releases capacity (reduces EEN) in the lines. The red areas indicate where adding a small amount of generation will have the greatest affect on releasing capacity, and therefore, potentially on the reliability of the delivery system.

This plot indicates that which feeders might be using a greater percentage of their capacity. Does this necessarily mean that this is the best place for generation? No. If the load is not growing much in these areas, this may not be of much concern. But this also means that if we are able to achieve a gradual influx of RDG into the highlighted areas, it may be possible to defer investment in new wires capacity for a very long time. Again, the two most heavily loaded subfeeders serving Bay Farm Island show up in the top 50% of locations.

Therefore, the released capacity analysis does not show the same optimal locations as the loss reduction analysis. Keep in mind that this is only part of the story. For RDG to have any real value for capacity purposes, it must be producing power at the proper times, which we have learned are the evening hours from December through February.

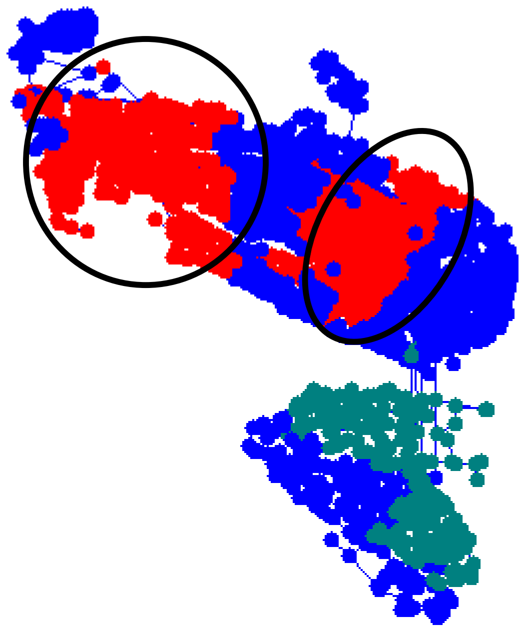


Figure 21: Optimal Locations For Small DG (100 Kw) With Respect To Releasing Distribution Capacity

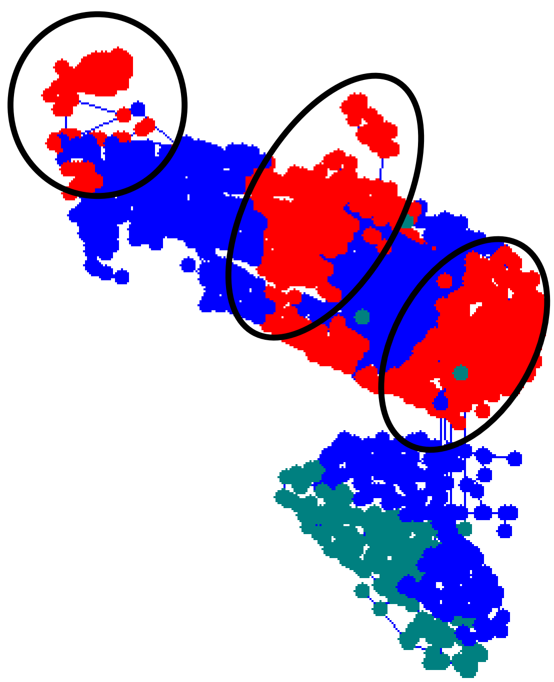


Figure 22: Least Optimal Locations For Small DG (100 Kw) With Respect To Releasing Distribution Capacity

It is also useful in this screen to identify the least helpful locations with respect to capacity and losses. The red areas in Figure 22 are those in which the least capacity is released by load reduction. The models of the feeders serving these areas show the most excess capacity. Therefore, DG applied in these areas is not as likely to help with reliability issues as it might in the blue and green areas.

Likewise, Figure 23 shows the least helpful with respect to loss reduction for a 100 kW test generator.

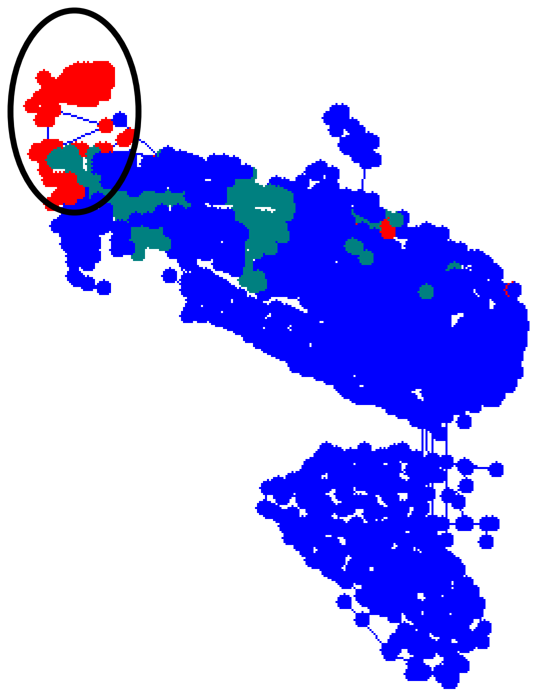


Figure 23: Least Optimal Locations For Small DG (100 Kw) With Respect To Reducing Losses

hese graphics show the relative rankings of the buses with respect to the criteria. This is a useful screen, but may not tell the whole story. While there is considerable difference in locations with respect to losses, there isn't much difference in released capacity between locations. For example, the feed to Bay Farm Island shows plenty of capacity, but DG there would certainly help system efficiency due to its remoteness from the substation. Therefore, we will pay more attention to losses than to released capacity for this report.

3.4.2. Large (5,000 kW) Test Generator

The previous analysis was repeated for a large generator (5 MW). This is approximately 50% of the capacity of a 12 kV feeder and a generator this large would be expected to actually increase the losses in some locations. Conventional wisdom would be that RDG reduces losses. That is generally true, but there is a limit to what one can place on a particular system without causing increased losses in some locations.

That is indeed what we find with this analysis. The range of loss reduction at peak load is from 6% of the generator size (30 kW) to a 3% (15 kW) *increase* in losses. Figure 24 shows the optimal locations with respect to losses in red. Conversely, Figure 25 shows the least optimal locations. In fact, these are locations where the losses will likely be increased by placing such a large generator.

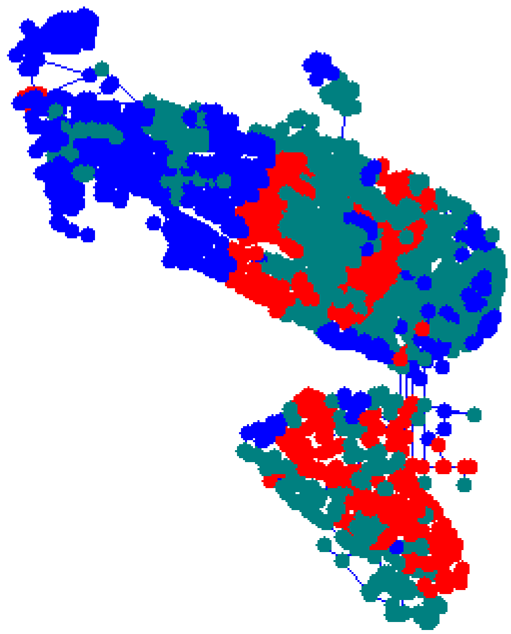


Figure 24: Optimal Locations For A Large RDG (5MW) With Respect To Loss Reduction At Peak Load

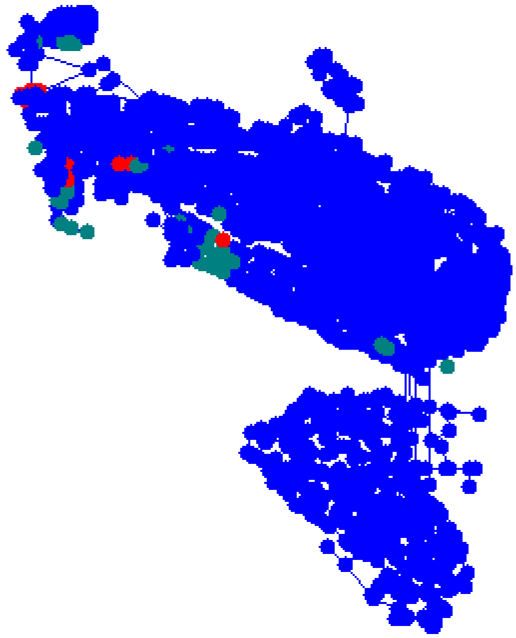


Figure 25: Least Optimal Locations For Large DG (5MW) With Respect To Losses. Placing such a large generator in these areas will likely overload the local system.

It is noteworthy that the area ranked in the upper 50% (green and red in Figure 24) is much larger than the 100 kW test generator. Many of the areas are the same. The likely reason is that since there are areas where the losses are virtually canceled as well as areas where the losses have significantly increased, the median value has shifted to include more buses in the top range.

The losses would increase for all the areas indicated in blue in Figure 26. Generation connected in these areas result in substantially more losses than the base case. Usually with this happens with a large test generator, it means that the conductor in these areas is too small and the current from the large generator actually increases the losses rather than decreases.

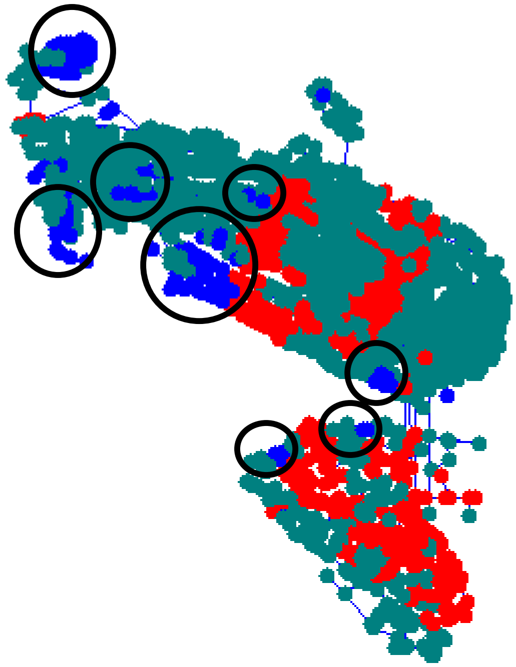


Figure 26: All Areas In Blue (Circled) Show An Increase In Losses For A 5,000 Kw Generator Added At Peak Load

It is interesting that some of the worst areas with respect to loss reduction are adjacent to some of the best. This is simply a reinforcement of how sensitive the distributed generation problem is to location and the actual system configuration. Since there are many switching options on the main part of Alameda, the switch configuration could probably be modified for a given proposed RDG application if the analysis shows that the location would result in significantly increased losses.

The optimal locations for a 5 MW generator with respect to capacity are shown in Figure 1 These areas are essentially the same as with the small generation.

Again, this analysis simply suggests that loading relief in certain areas fed by Cartwright and a couple of feeders out of Jenney, would have the greatest percent improvement in capacity available. This simply indicates the areas that use a greater percentage of their rated capacity. However, there is relatively little difference between the areas.

Since 5 MW is such a large amount, it frees up nearly 75% of the capacity of some feeders. This would contribute to reliability by permitting loads normally fed from other feeders to be served from the feeder with the generation in an emergency. The impact on reliability is evaluated by the annual simulations in the Reliability Analysis.

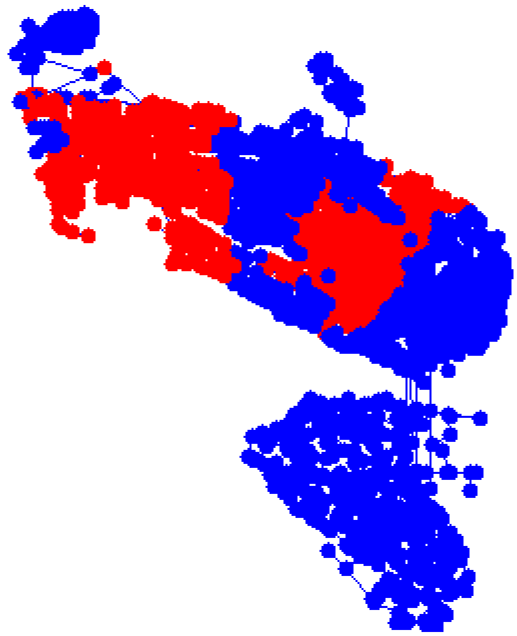


Figure 27: Optimal Locations For A Large DG (5 MW) With Respect To Released Capacity

3.4.3. Base Case (No RDG)

To compare the RDG 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:

Peak Power Losses:	**1,685 kW, or about 2.5% of total load**
Annual Energy Losses:	**1.53% for the same model assumptions**

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.

From the engineering viewpoint, this value is relatively low compared to other 12 kV systems we have studied. The primary reason is that the lengths of the lines are relatively short due, in part, to the naturally limited geographic layout of the city. The feed to Bay Farm Island is longer than the remainder and contributes a significant portion of the power delivery losses. In addition, the cables and lines are not what heavily loaded, which results in lower than typical losses. Having plenty of capacity generally makes it easier to accommodate a large amount of RDG, but also makes it more difficult to realize value in reducing losses and freeing capacity.

The Jenney 2 bus is operated at high voltage (we assumed 126V on a 120V base) to compensate for the voltage drop in the long feeds to Bay Farm Island and one other more distant area of the City. One potential conflict this causes is that large amount of RDG power injected into the bus at Bay Farm Island may cause a voltage rise, requiring a different regulating strategy while the generation is connected.

The base case will be compared to two reference RDG cases and then to a proposed 20 MW baseload plant on or near Bay Farm Island. We will assume that Alameda P&T will build a line from the station to a point of connection on Bay Farm Island. The other main option is to connect the plant to the PG&E transmission system and use it to deliver the power to Alameda P&T. This does not alter the present loss and capacity situation and is not of interest in this engineering screening analysis.

The two references cases are designed to yield information about the potential capacity of the Alameda P&T system to accommodate RDG. They will serve as points of reference for the proposed plant. The two cases chosen here are:

1. 8 MW of generation distributed in 16 500-kW increments in a manner to minimize losses. This might represent a number of CHP systems and peaking units designed for optimal benefit to the power delivery system. This will provide some idea of potential operating conflicts and the amount of benefit possible if we were actually able to dictate locations for such dispatchable generation.

2. 2 MW of widely dispersed small generation such as solar photovoltaics distributed uniformly over the system in proportion to load. This should give an idea of what might be possible if an ideal distribution of such renewable generation were to be achieved.

3.4.4. Reference Case 1: 16-500 kW Generators

To establish this case, 8 MW of RDG were sited in 500 kW increments to achieve maximum loss improvement at peak load. The locations chosen are shown in Figure 28. The resulting losses computed are:

Peak losses: ***1,125 kW***

Savings: ***560 kW less than the Base Case.***

This configuration of generation cancels nearly half the primary distribution losses at peak load, which is quite remarkable, considering that the capacity of generation is only about 12% of the load. The generator siting algorithm places them such that the current in some of the longer and more heavily loaded lines is greatly reduced.

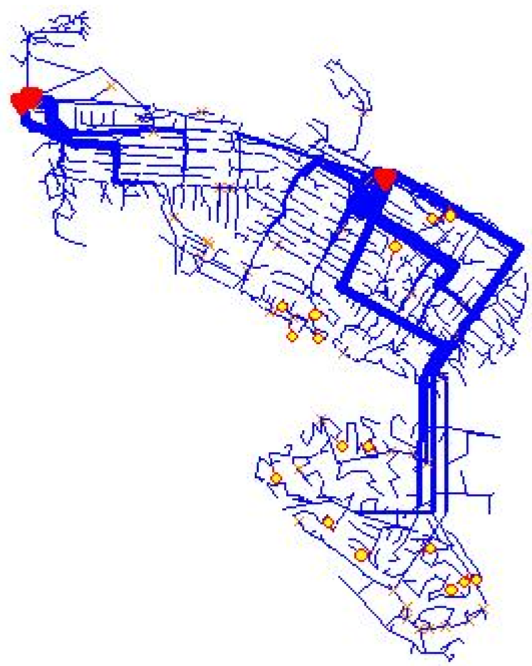


Figure 28: "Optimal" Locations (Yellow Circles) For 8 MW Of DG Sited For Maximum Loss Reduction At Peak Load

At peak load, the saving in losses equals approximately 7% of generator capacity. This is a relatively large value, but the reader should keep in mind that this applies only to the peak load condition and that this gain generally declines in percentage as the amount of generation increases. At low load conditions, the losses could be larger than without any RDG. The annual simulations show that the average is 3.7% of generation capacity. Some thick lines remain in Figure 28, suggesting there are still some efficiency gains to be had. Whether the cost to achieve these gains is worth it must be evaluated.

Peak losses are only part of the story because the annual savings will depend on how the generators are dispatched. If the generators are dispatched as peaking units, they will achieve significant loss savings. However, this is not guaranteed for CHP units that run all the time. 8 MW may be too much for light load conditions, which will actually increase the losses. The Reliability Report will address these issues in more detail. Dispatching the generation as either baseload or peaking is considered.

The next engineering question to evaluate is: Can the system accommodate this kind of generation? The two most likely problems accommodating large amounts of RDG on radial distribution systems are:

1. Voltage Regulation
2. Overcurrent Protection Coordination.

These are the next two areas we investigate for this proposed configuration.

3.4.4.1. Voltage Regulation Screen

Voltage regulation is evaluated in two steps:

1) Voltage drop when the RDG suddenly disconnects;

2) Voltage rise when all generation comes on.

The first condition will definitely occur as RDG exits the system under fault conditions so that the utility overcurrent protection (breakers, fuses) can perform their functions. Whether the latter condition will be significant depends on how the RDG is dispatched.

Figure 29 shows the results of the voltage drop simulation. The system was modeled at peak load with all 8 MW of RDG operating at near unity power factor. Then the RDG was disconnected and the voltages computed before the voltage regulation devices would have a chance to act. A small area on Bay Farm Island is shown with a mild undervoltage. This would be corrected shortly afterward by action of the substation tap changer.

A greater concern with this RDG configuration might be the voltage rise were all the RDG to come on all at once. The voltage rise is about 1.6% above normal maximum. The areas shown in blue in Figure 30 would run a little high until the substation tapchanger reacts. This should be approximately 1 minute or so. An occasional excursion this high is of little consequence. However, if this generation were to be dispatched in this manner each day, the life of incandescent lamps might be noticeably reduced in the area shown.

This is important to keep in mind as we later investigate the injection of 20 MW from the proposed RDG plant into Bay Farm Island. The computed voltage excursions are similar.

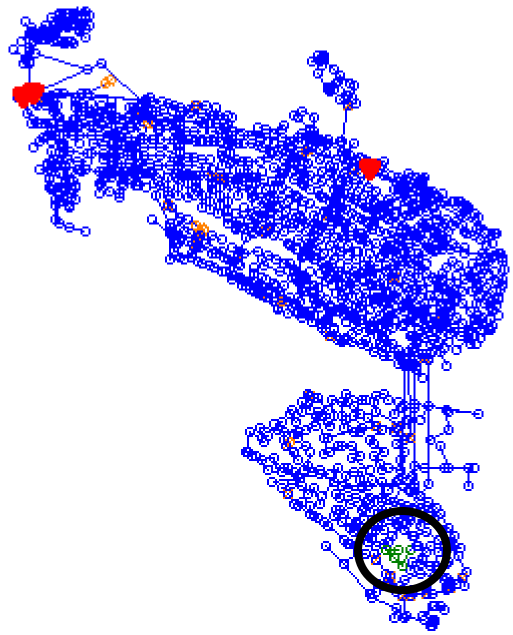


Figure 29: Area In Green (Circled) Indicate Mild Undervoltages Immediately After Dropping 8 MW Of Generation Distributed As Indicated In Figure 28

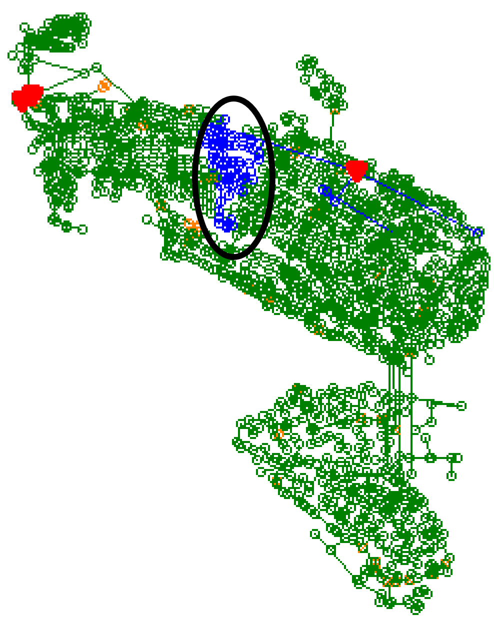


Figure 30: Areas Shown In Blue (Circled) Would Experience A Moderate Overvoltage If All Generators Shown In Figure 28 Were Dispatched On Simultaneously

3.4.4.2. Overcurrent Protection Screen

The next concern is the interference of the RDG with the overcurrent protection scheme. One screen is to compute the amount of infeed into short circuits from the proposed generation.

Figure 31 illustrates the degree to which the fault current will increase assuming the RDG is synchronous generation and can contribute to faults. The darker red areas indicate a higher percentage change from the base case without RDG. The darkest red signifies approximately a 105% increase, or more than double the original value. It is not surprising the greatest percentage change takes place where RDG is applied farthest from the substation. This means the RDG is contributing a significant amount of the fault current at those location and appears to have a strength comparable with the utility system. One engineering concern is that the substation relays will not be able to "see" high impedance faults. Their minimum pickup settings may have to be adjusted or more line reclosers added. There are already line reclosers on Feeders 4212 and 4214 just before the cable drop to Bay Farm Island, so it is likely modifications can be made there, if required, to adjust the settings to accommodate the generation.

Another concern is the lateral fusing, which is chosen to coordinate with the system without the RDG. Sometimes, lateral fusing in the areas where there is a large change in the system must be increased in rating to satisfactorily coordinate. However, this is mainly a problem with fuse saving coordination, which we understand is not being employed in this case. The generator infeed in this case would actually help the fuse blow and should aid coordination for faults that can be detected.

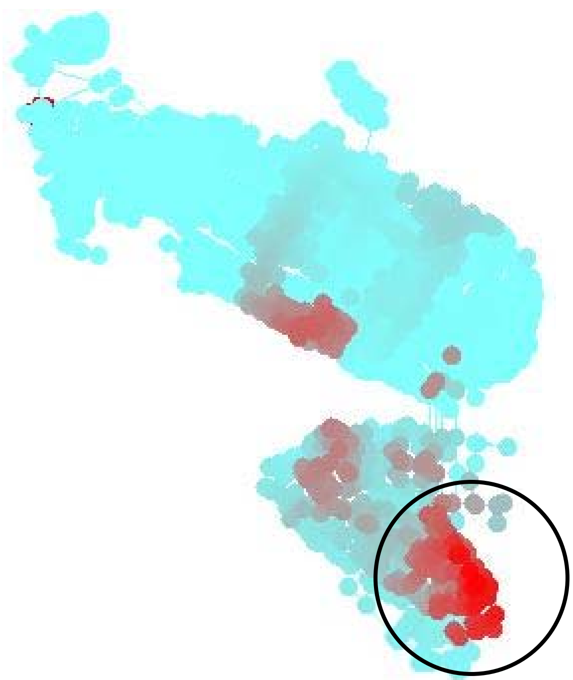


Figure 31: Indication Of Percent Increase In Fault Currents, assuming DG is capable of supplying fault current. Fault currents in the circled red areas increase to as much as double their original value. Range is from zero to 105%.

The percentage increase indicates where mis-coordination is likely, but is only part of the story. Figure 32 shows a similar graphic where the colors indicate the actual magnitude (not percentage) increase in the fault current. This is important for determining the interrupting ratings of the devices. The brightest red color (which shows darkest in monochrome) in this analysis indicates a 3100 A increase, which is substantial.

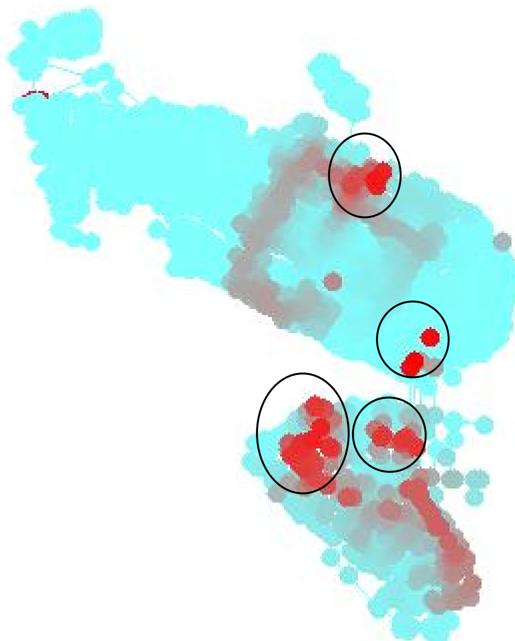


Figure 32: Locations In Red (Circled) Indicate High Increased Fault Current (Amperes) Due To Added Generation. Range From Light Color To Darkest Red Is 0 To 3100 A Increased Current.

The fault currents increase the most near the substation where all the feeds come together and on Bay Farm Island near where the most generators are assumed to be interconnected for this reference case. The main concern here is with the interrupting ratings of the breakers and fuses will be exceeded in these areas. This particular arrangement of RDG will take the fault current at Jenney 2 bus above 11 kA. When this causes a problem for breakers (not expected, but possible), the fix can be quite expensive. The breakers must be replaced. If the fuse interrupting ratings are insufficient a more capable fuse must be employed in areas of high fault current. This is not as costly as changing a line of breakers, but may also not be trivial. There may be dozens of fuses to change out.

Alameda P&T currently identifies a "High Fault Area" on their one-line diagram that is based largely on the distance from the substation. The consequence of the RDG infeed in this case is that other areas may also have to be designated similarly and it won't be so easy to determine the high fault area. If Alameda P&T has been doing something special in these areas, such as applying current-limiting fuses, that same practice will now have to extend to parts of Bay Farm Island.

The reference case serves to illustrate several of the principles of screening for engineering feasibility.

3.4.5. Reference Case 2: Distributed PV

This reference case simulates the distribution of 2 MW of small generation across the distribution system. This might represent 1,000 2 kW residential solar PV units, for example. This would represent the result of an ambitious, long term solar power incentive program. The assumed distribution was generated randomly and the locations are shown in Figure 33 overlaid on the power flow graphic.

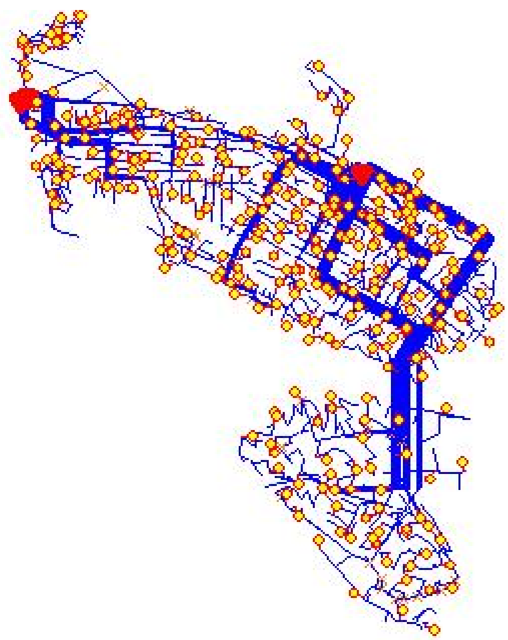


Figure 33: Assumed Locations For Solar PV Units Totaling 2 MW.

The total peak load loss savings for this case are could be approximately 120 kW *if the load peak were coincident with the generation peak*. This would be 6% of the amount of generation added and represent a 6.5% saving of peak system losses. One would expect a more-or-less uniformly distributed source of generation to yield good results for loss reduction because the current is decreased somewhat uniformly throughout the system. 6% of generator capacity is a reasonably good figure. However, it is not as good as the previous case where the generation was sited explicitly to reduce losses, which yielded a loss reduction of 11% of the generation capacity. The more uniform distribution of generation in this case does not address the losses in the longer lines as well.

Another issue this does not address is whether the generation will be available at the peak load period. The answer to this will become more apparent from the annual simulations in the Reliability evaluation in the next subtask in this project. At the outset, it looks to be a potential problem with solar PV generation because the peak load occurs in the winter in the early evening when there is little or no solar power available.

3.4.5.1. Voltage Regulation Screen

As with the previous reference case, the impact of this generation on voltage regulation was evaluated in two steps. All the generation would have to disconnect for a few minutes following a major disturbance, such as a momentary interruption on the transmission grid. Then the reverse condition was simulated.

For the first case, the maximum voltage change was 0.44% (drop). This is inconsequential and not unexpected since 2 MW is only about 3% of the load.

Going the other way, if we assume that all the generation comes back on at once, the maximum voltage change is 0.45% (rise) on Bay Farm Island. In our simulations, the substation tapchangers did not change. With the generation distributed throughout the system, there is no one feeder that experiences concentrated impacts on voltage regulation.

An interesting analysis is to determine how much of such widely dispersed generation can be accommodated before the voltage change is 5%. This is an informal guideline used by Electrotek for the maximum allowable voltage change when the generation is forced off in response to a system disturbance. If the voltage change is greater, it is very likely that expensive changes will have to be made to the distribution system. This analysis was done by increasing the generation by a factor until the voltage dropped exceeded 5% when it was forced off. This is one indication of the maximum amount of RDG that can be accommodated under ideal conditions without expensive changes to the distribution system. The results are shown in Table 12.

Table 12: Voltage drop for different amounts of RDG distributed as shown in Figure 33.

Total RDG	Voltage Change
8 MW	1.74%
16 MW	3.29%
24 MW	4.59%
32 MW	5.69%

Based on this, one would estimate that the total amount of uniformly distributed RDG that could be accommodated without major changes would be approximately 30 MW. Keep in mind that this assumes a widely dispersed amount of generation distributed proportionately to the load. If the RDG were concentrated in a specific area, problems are likely to arise at much lower amounts of RDG. Each case should be evaluated separately.

30 MW is approximately 40% of the present peak load. Compared to other systems we have studied, this is a high value. Voltage regulation issues typically arise when total

RDG capacity is in the range of 10 to 30% of design capacity. If the RDG is located closer to the substation, the 5% voltage change will occur toward the upper end of this range. Conversely, if the RDG is located more distantly from the substation, a lower percentage can be accommodated before having to make changes to the distribution system. This result suggests that the Alameda P&T system is shorter, on average, and/or the system is not as heavily loaded as other 12 kV systems we have studied.

3.4.5.2. Overcurrent Protection Screen

Solar PV generation is interconnected through inverters. We do not consider inverter-connected RDG to be a significant source of fault current. Once currents approach 2 per unit in the inverter, the inverter will typically abruptly cease to energize the system. Therefore, we do not perform the tests as illustrated in the first Reference Case.

This does not mean that such generation will not interfere with utility protection coordination in some other way. Numerous anecdotes of extended inverter run-on have been reported to us. Such malfunctions are certainly plausible given the number of inverters that would have to be in place to supply the amount of power in this case study. We assume in this type of screening study that the inverters function properly and disconnect when the fault occurs or shortly after the utility feeder breaker opens. Therefore, they are assumed to pose no problems with respect to impacting relay sensitivity or breaker interrupting ratings.

3.4.6. 20 MW Baseload Generation

The chief RDG proposal on the Alameda P&T system is to operate a 20 MW plant powered by renewable fuels on or near Bay Farm Island.

There are basically two alternatives for delivering the power from this generation:

1. Interconnect with PG&E and use their transmission lines to bring the power to Alameda.

2. Lay cables from the plant to Bay Farm Island and inject the power into the 12 kV circuits.

The first option has no impact on the present operation of the Alameda P&T system because the power will be delivered through the two main substations as is presently done. This option has interest from economic considerations, but is not of much technical interest. Therefore, we will study the second alternative listed above because of its potentially favorable impact on the Alameda P&T distribution system with respect to efficiency, reliability, and capacity to serve more load.

There are a number of options for interconnecting the generation. We will investigate two in detail:

1. Running two 12 kV feeders from the proposed plant and directly connecting into the four subfeeders on Bay Farm Island through line reclosers (Figure 34).

2. Running a single 35 kV line from the proposed plant to a point on Bay Farm Island and interconnecting to the four subfeeders using four 5000 kVA padmounted transformers and a recloser with each (Figure 35).

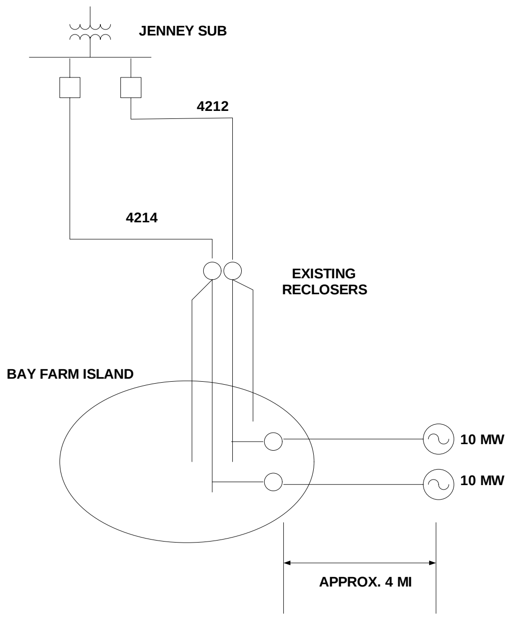


Figure 34: Option 1: 2 12 kV feeders

It is assumed that the cable has the same impedance as the cable presently used in the channel crossing. The length of cable required is estimated at between 3 and 5 miles depending on the actual siting. For the study, the length was assumed to be 4 miles.

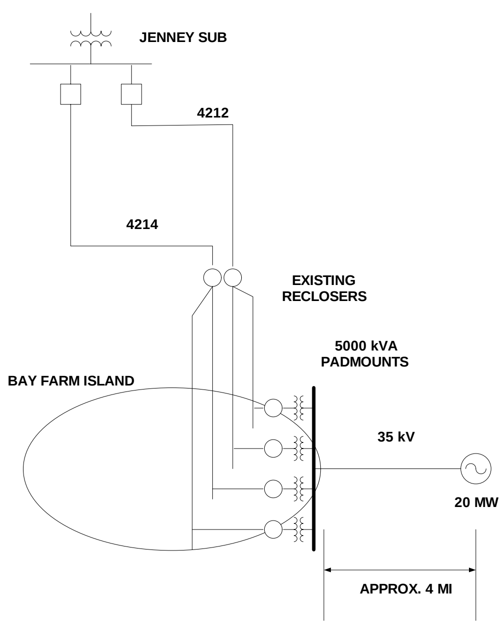


Figure 35: Option 2: A 35 kV Feeder And Transformer Stepdown.

In both options, the two sets of subfeeders become looped. This will necessitate modifications to the overcurrent protection scheme on these feeders and may result in loop flows. In Option 2, Feeders 4212 and 4214 essentially become looped through two transformers in series, the impedances of which should help control loop flow. This portion of the system becomes operated more like a transmission system than a distribution system. Some loop flow may come about, but the larger issue is likely the impact on existing overcurrent protection.

The added reclosers could be relayed as typically done for distribution-connected RDG. The primary relaying quantities will be voltage and frequency supplemented by overcurrent and, possibly, negative sequence relaying. The main function of the relaying is to disconnect the RDG so that the feeders revert to radial allowing the fault clearing to proceed from the present overcurrent devices. An alternative would be to apply impedance relaying somewhat like a transmission system. Many distribution utilities do not consider this alternative because of cost and lack of familiarity with operating personnel with this type of equipment.

3.4.6.1. Voltage Regulation Screen

The following figures depict the voltage screen results for the first option for connecting to the proposed plant. The second option yields very similar results and the results are not repeated.

These results are quite similar to Reference Case 1, which has substantial generation installed in the same general area. The undervoltages are not severe and should be corrected promptly. However, the tap changer in the Jenney 2 transformer may have to be adjusted down slightly to avoid overvoltages when the generation ramps up.

In this screen, the generation is assumed to produce unity power factor, which tends to minimize voltage regulation problems at the point of interconnection. However, there is always some impact. If the generation is permitted to produce significant reactive power, the voltage regulation issues could be greater than predicted in this analysis. Producing reactive power would tend to raise the voltage, which would tend to drive the tap on the Jenney 2 transformer down. Then when the generation is forced off, the feeder voltages would drop lower than this analysis predicts.

Another reason for assuming a unity power factor is that some technologies that might be applied, such as a string of fuel cells or microturbines interface to the power system through inverters. When operating in what is known as utility interactive mode while interconnected to the utility system, the inverters neither produce reactive power nor attempt to regulate the voltage. It is costly to provide the required extra capacity in an inverter while rotating machines have some inherent capability to absorb or produce reactive power in addition to rated active power.

Figure 36: Option 1: Areas In Green (Circled) Will Have Mild Undervoltages If The Two 10 MW Generators Is Forced Off.

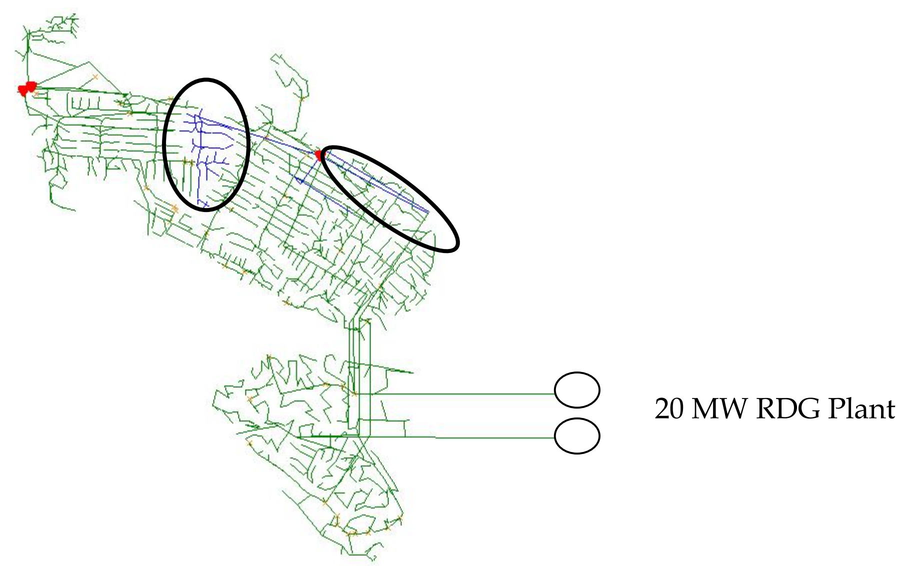


Figure 37: Option 1: Areas In Blue (Circled) Will Have Moderate Overvoltage When The Two 10-MW Generators Are Brought On Line Suddenly At Peak Load.

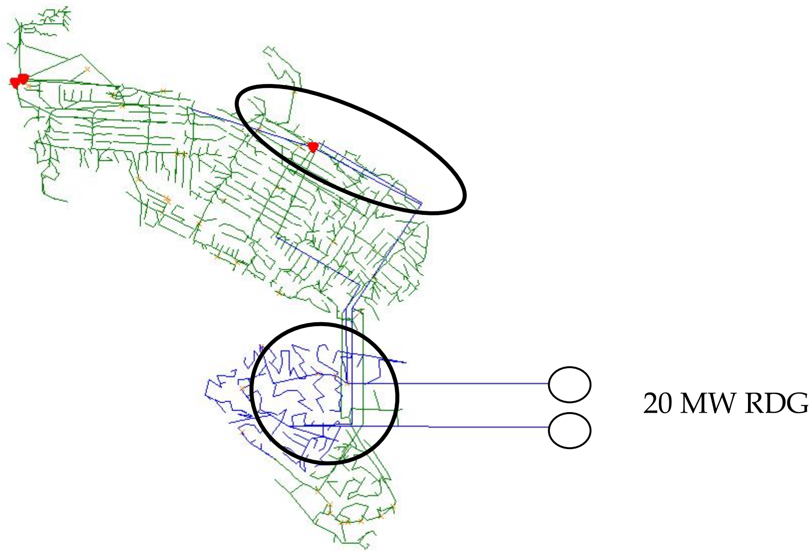


Figure 38: Option 1: Areas In Blue (Circled) Will Have Moderate Overvoltage When The Two 10-MW Generators Are Brought On Line Suddenly At 50% Load.

It would appear that voltage regulation issues would be manageable for either option. While interconnected, the generation will typically operate in a grid parallel mode with constant power factor or constant reactive power. Operating under voltage control (variable reactive power) would require more careful engineering as well as enhanced communications and control to coordinate voltage regulation with the existing system.

3.4.6.2. Loss Comparison

The peak load losses for Option 1 are shown in Table 13. The net losses of 1790 kW are nearly 105 kW higher than the losses for the present system. However, the actual losses in the existing system are reduced by some 480 kW. 585 kW losses are incurred delivering the 20 MW through the 12 kV cables from the plant to the interconnection point on Bay Farm Island. This amount would vary linearly with cable length if actual lengths are different than assumed.

Table 13: Peak Load Losses for Option 1

Total Losses	1,790 kW
DG Line Losses	585 kW
Existing System	1,205 kW
Savings	480 kW

The losses at peak load for Option 2 are listed in Table 14. The net savings in peak load losses achieved for the existing system is comparable to Option 1. However, only 220 kW losses are incurred in the delivery of the power through the 35 kV line and transformers, which is less than half the losses for the two 12 kV lines.

Table 14: Peak Load Losses for Option 2

Total Losses	1,450 kW
35 kV Losses	180 kW
Transf Losses	40 kW
Existing System	1,260 kW
Savings	430 kW

This would appear to be an improvement over Option 1, although it is not clear at this point that it would be a sufficient savings over the year to be economical. The cost of the 35 kV system should be comparable to the proposed 12 kV arrangement. Both 12 kV and 35 kV equipment are commodity items. The difference in equipment between the two options is basically one 35 kV cable and 4 transformers compared with two 12 kV cables. This savings could be substantial, especially if submarine cables are laid in the channel.

The loss savings over a year is not so obvious. Assuming the proposed plant operates year-round, the loss savings in Option 2 over Option 1 should be approximately 320 x 8760 = 2,803,200 kWh. However, the total losses in the system actually increase for both options because the generation constantly ships 20 MW back up the lines from Bay farm Island to Jenney. Presently, the load in these lines cycle each day, with few losses during light load periods. See *Annual Energy Simulation Comparison* below for a presentation the losses estimated by annual simulation.

The downside of building only one 35 kV line is lack of redundancy in case of cable failure. This puts Alameda P&T at risk of not being able to access the generation for extended periods while the cable is being repaired. This may be an acceptable risk because the load can still be served from the present system without the generation. The risk might be hedged with an acceptable purchase power agreement. If there were two 35 kV cables, full redundancy could be achieved. In that case, the cable installation would likely be more costly than the 12 kV option, leaving the economic justification largely up to the loss savings in delivering the energy from the plant to Bay Farm Island. With two 35 kV cables, the losses would drop by approximately 135 kW, yielding a net savings of 450 kW at peak over the 12 kV line option.

3.4.6.3. Overcurrent Protection Impact Screen

Figure 39 through Figure 42 depict the areas with the largest percentage and actual absolute value change in fault current for each of the two options for the generation interconnection. These charts show the relative values for each option, but do not provide a frame of reference between the cases. Table 15 shows the numeric comparison between the two cases. The equivalent net transient reactance assumed for the generators was 27%.

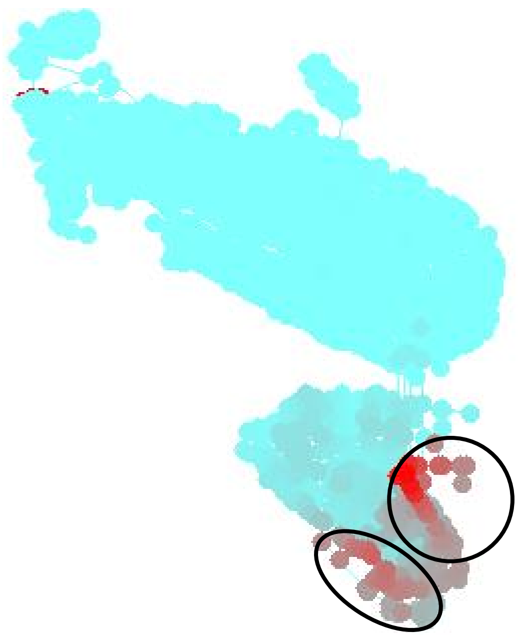


Figure 39: Option 1: Areas With Largest Percent Change In Fault Currents (Max = 62%)

This overcurrent protection screen shows that the greatest impact, as one might expect, occurs near where the generation is interconnected at Bay Farm Island. Where the percentage of fault current change is large, one might anticipate mis-coordination with fuses and minimum pickup settings for detecting high impedance faults. Where the change in current magnitude is large, there is concern for the duty on devices and increased damage to lines and cables.

Figure 40: Option 1 - Areas With Largest Absolute Value Change In Fault Currents (Max=1800 A).

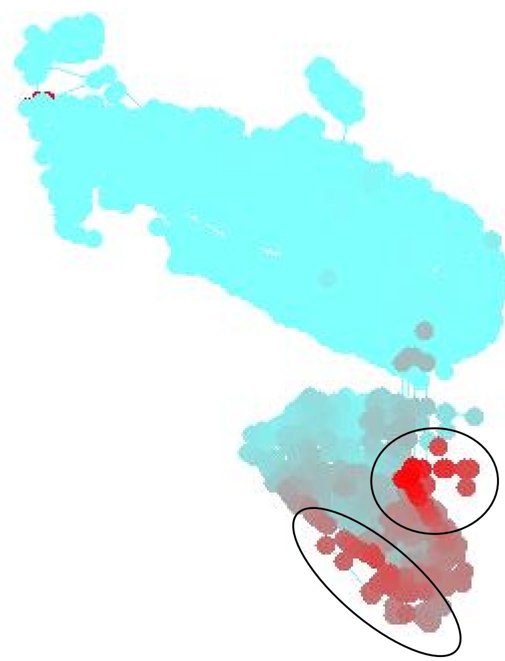


Figure 41: Option 2: Areas with largest percent change in fault currents (Max = 27%).

These results suggest that the 35 kV option (Option 2) will have less impact on the overcurrent protection than 12 kV option. The added impedance of the four step down transformers assumed for this option provides significant separation between the feeders and subfeeders and limits the fault contribution from the plant. It should also make it easier to achieve proper interface connection.

This analysis is a screen to predict potential problems and compare RDG options. Actual design of the overcurrent protection for either of these two options is outside the scope of this project.

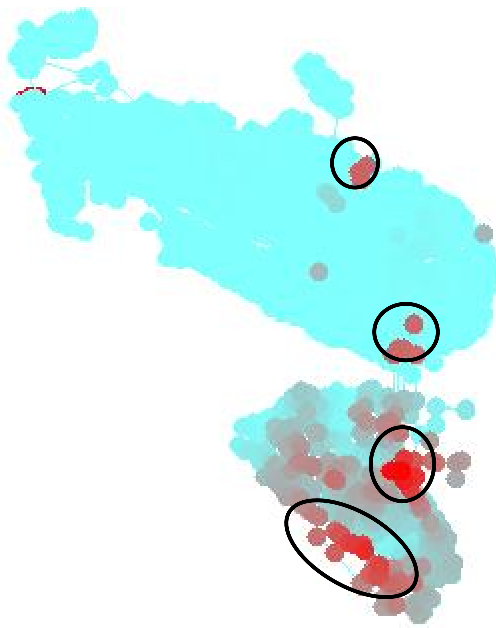


Figure 42: Option 2 - Areas With Largest Absolute Value Change In Fault Currents (Max=818 A).

Table 15: Comparative Impacts of Two Generation Interconnection Options on Overcurrent Protection of Alameda P&T System

	Option 1 (12 kV)	Option 2 (35 kV)
Max % change	62%	27%
Max Ampere Change	1800 A	818 A
Amps Increase at Jenney 2	1045 A	700 A

3.4.6.4. Annual Energy Simulation Comparison

An annual simulation of the base case and the two interconnection options was executed. The results of the energy comparison analysis are summarized in Table 16. Both options considerably reduce the amount of energy purchased from the transmission system. The assumption made in both cases was that the 20 MW of generation would be available 8760 h per year, which is perhaps unrealistically optimistic. However, it serves for the purposes of comparing the two options.

The net energy into the Jenney 2 substation transformer reverses by this assumption by approximately 29,000 MWh (avg of 3.3 MW reverse power flow). The excess energy is consumed through the Jenney 1 transformer which shares a common 115 kV bus. The current in the PG&E transmission lines is reduced to the point that there is approximately 320 MWh annual savings in losses in the local transmission system for either option. No attempt was made to determine the impact on the entire transmission grid.

Table 16: Comparison of Annual Energy for Generation Delivery Options

	Base	Option 1	Option 2	Difference Opt. (2) - (1)	
Total % Losses	1.53%	2.54%	1.83%	-0.71%	
Delivery Losses	---	4,774	1,927	-2,847	MWh
System Losses	5,191	9,969	7,118	-2,850	MWh
Purchase Power Savings	---	171,003	173,759	2,756 (1.6%)	MWh
Transmission Loss Savings	---	316	322	5.85	MWh

Injecting a large amount of power into Bay Farm Island tends to reduce the losses in the existing system. However, losses are incurred in the delivery of that power and currents in the main feeders (4212 and 4214) are at an average higher level than at present. Therefore, the total losses in the system actually increase. The model shows an annual loss of 1.53% in the portion of the distribution system that is modeled. There are other losses in distribution transformers and secondary feeders that are not included in this analysis, but the injection of power from the proposed plant will not result in any change in those losses. Option 2 results in only slightly more losses than the existing system and represents a savings of approximately 2,850 MWh over Option 1. The difference in these losses is largely the difference in the delivery losses.

Of course, the greatest potential benefit is related to purchased power savings, which total in excess of 170,000 MWh under these assumptions. The difference between the two options with respect to this number is approximately 1.6%. Since this is a small number, the two options might be considered virtually equivalent from the engineering perspective with respect to energy delivery.

The decision on which design to build will rest on reliability. Option 2, with only one 35 kV line, will not be able to deliver any power if the cable fails. Option 1 could deliver somewhat more than half the power if one of the two cables were to fail. As stated earlier, two 35 kV cables would make the system fully redundant since one cable can carry the entire plant generation. With two cables, the delivery losses would drop to 740 MWh, yielding a total savings of approximately 4,000 MWh over the 12 kV option. The question now becomes: Does this savings and the increased delivery reliability sufficient to justify the additional cost of the more capable system?

4.0 Load and Resource Analysis

An important element of RDG assessment is the evaluation of the fit between local load shapes and RDG output shape. The more coincident the RDG output shape is with the load shape, the greater the benefits to the system, particularly in terms of deferring distribution investment. This chapter contains information on Alameda P&T load shapes and the impact of characteristic RDG output shapes on peak load reduction and losses.

4.1. Local Area Load Shapes

Alameda P&T provided E3 interval load shape information that had been collected from their own meters and from the Northern California Power Authority (NCPA) metering of the whole Alameda P&T system load. The data span from 1996 through 2002, and include the system-wide load from NCPA and data from the Jenney and Cartwright substations provided by Alameda P&T, though not all data is present for all years. Because of the anomalies of the metered load data, the system-wide load shape was also used for the analysis.

Our 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 load value is plotted. The result is an image representing Alameda P&T's load shape over the course of 1998, as shown in Figure 43.

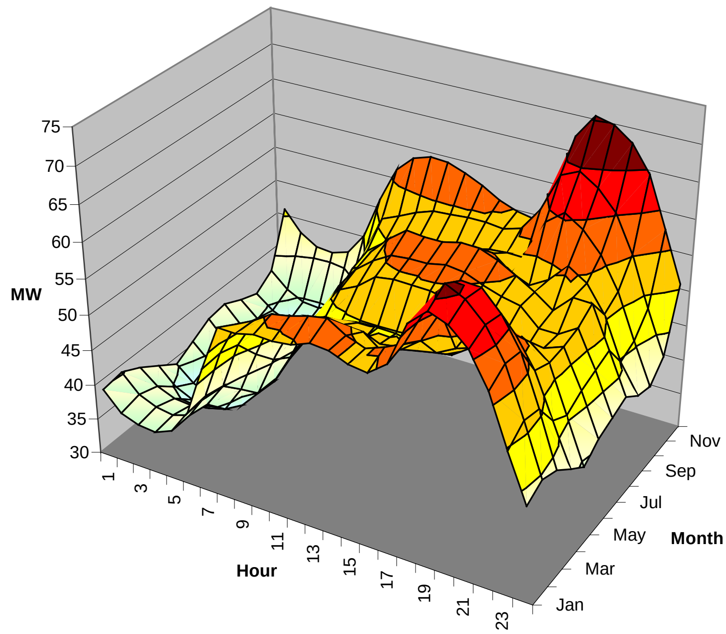


Figure 43: Alameda P&T System-Wide Load Shape, 1998

As seen in Figure 43, Alameda P&T's peak occurs during the evening hours (approximately during hours 17 – 22) of winter months with a peak load of a little over 70MW (70,000kW) around 7pm in December and a slightly lower peak in February of 1998. The data from Figure 43 are shown as a topographical chart in Figure 44. The topographical chart shows the same information, but displays the exact peak load timing more clearly.

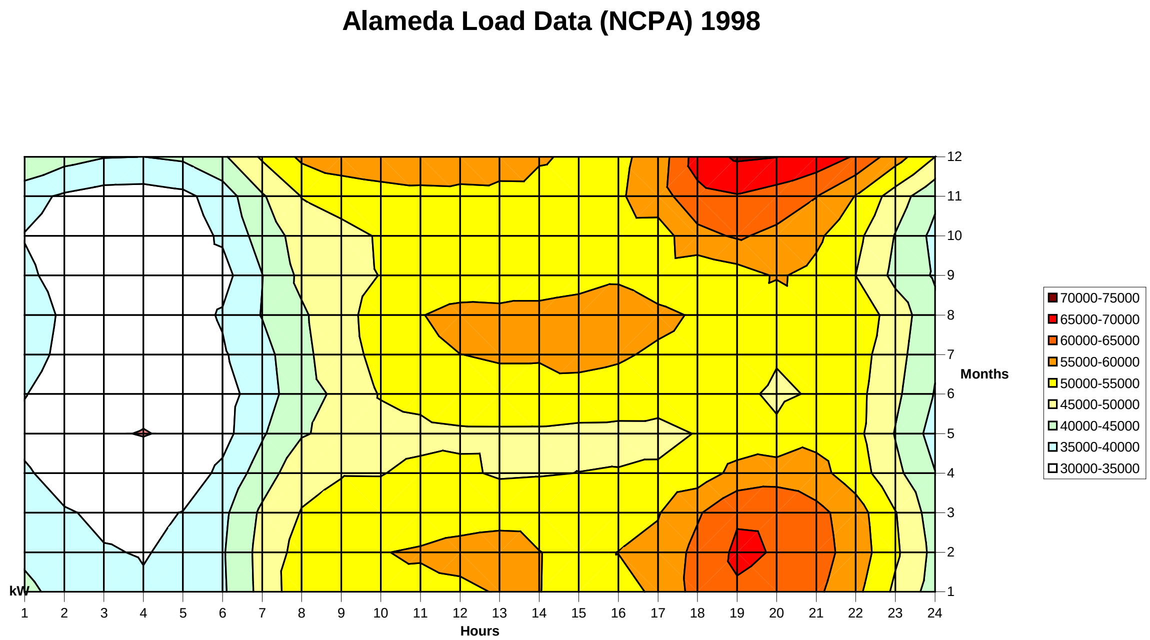


Figure 44: Topographical Representation Of Alameda P&T System-Wide Load Shape

4.2. RDG Output Characteristics

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

The output pattern and the location within the Alameda P&T system change both the renewable generator's ability to provide peak load relief (based on coincidence with the system profile above) and reduce losses. The following sections summarize the contribution of each of the load shape's impact on local system peak load, energy requirements and losses.

4.3. Summaries of Demands and Savings

The primary case investigated in this analysis was a 20MW base loaded RDG to meet present and future demand on Bay Farm Island. Two reference cases were also analyzed to establish benchmarks for comparison purposes, which included 2 MWs of distributed solar PV and 8 MWs of 500kW CHP units operated either as a peaking unit or a base load unit. Table 17 through

Table 19 show the savings in power demand and losses for each of the RDG options considered in this analysis.

Table 17: Purchased Power and Demand Savings

	Gen Size	Purchase Power Savings		Peak Demand Savings	
Case	MW	MWh	% of Gen	kW	% of Gen
2 MW PV	2	3,706	103.0	0	0.0
8 MW CHP Peaker	8	21,356	104.5	3,653	45.7
8 MW CHP BaseLoad	8	72,692	103.7	8,559	107.0
20 MW Baseload 1	20	170,773	100.3	16,569	82.8
20 MW Baseload 2	20	174,277	100.2	16,111	80.6
20 MW Baseload 1*	20	171,003	97.6	16,532	82.7
20 MW Baseload 2*	20	173,760	99.2	16,197	81.0

* includes delivery losses for RDG

Table 18: Annual Energy Loss Savings

Case	Gen MW	Annual Loss Savings		
		kWh	%	% of Gen
2 MW PV	2	109,115	1.8	3.0
8 MW CHP Peaker	8	916,235	15.4	4.5
8 MW CHP BaseLoad	8	2,615,144	44.0	3.7
20 MW Baseload 1	20	791,268	13.3	0.5
20 MW Baseload 2	20	402,261	6.8	0.2
20 MW Baseload 1*	20	-4,023,714	-67.7	-2.3
20 MW Baseload 2*	20	-1,173,370	-19.7	-0.7

* includes delivery losses along new line from generation location

Table 19: System Loss Savings at Peak Load

Case	Gen MW	Peak Loss Savings	
		kW	%
2 MW PV	2	0	0.0
8 MW CHP Peaker	8	247	14.6
8 MW CHP BaseLoad	8	561	33.2
20 MW Baseload 1	20	480	28.5
20 MW Baseload 2	20	428	25.4
20 MW Baseload 1*	20	-102	-6.0
20 MW Baseload 2*	20	239	14.2

* includes delivery losses for RDG

Note that we have separated the two options for interconnecting the 20 MW generation to Bay Farm Island to specify individual cases both with and without delivery losses included. In the cases indicated with "*" the losses in the cables and transformers assumed for the interconnection are included. Including delivery losses results in negative savings in the annual losses column (see Table 18). The reason for this is that the generation is assumed to operate at a constant output of 20 MW while the load cycles up and down. This results in an additional constant loss that was not present prior to adding the new generation. However, the losses in the existing system actually decline in this case.

Each case shown above is described in more detail in the following sections.

4.3.1. 8 MW CHP Generation Characteristics

As a reference case to gain understanding of the system and to establish a benchmark for what might be possible with RDG 16 combined heat and power (CHP also known as 'cogeneration' projects) generators, 500 kW each, were sited to both reduce peak losses and to reduce the overloading on the lines. CHP units could include microturbines or fuel cells using a renewable fuel. Because the overloading in the normal condition is minimal, the main siting criterion is loss reduction. Using our model, we determined the best locations to install these CHP units on the Alameda P&T distribution system. These are shown in Figure 45.

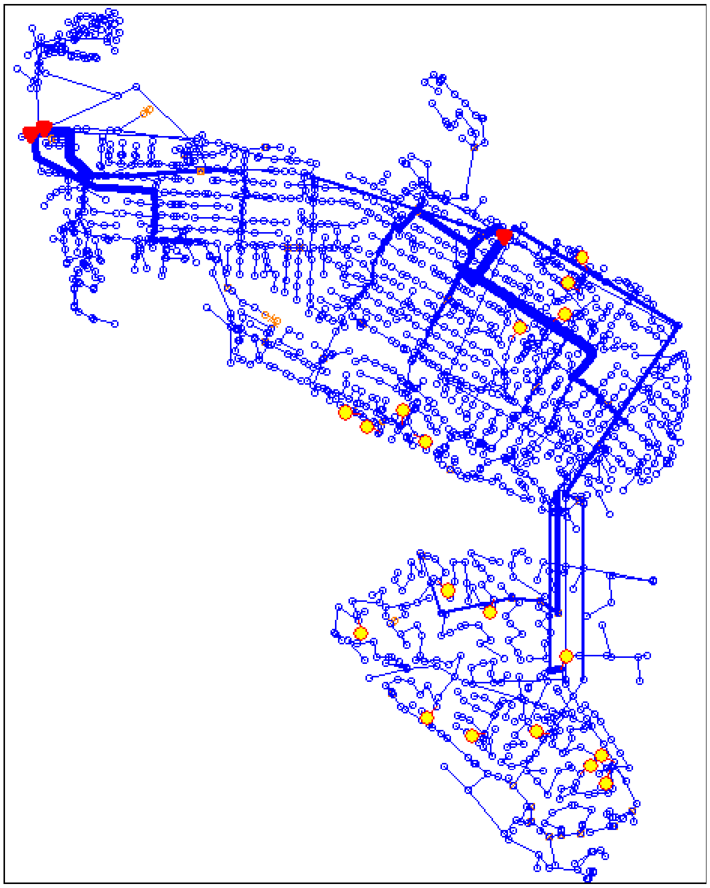


Figure 45: Location Of 16 500-Kw Generators For Optimal Loss Reduction At Peak Load. Generator Locations Are Marked With Yellow Circles.

This 8 MW of generation was simulated as operating in two modes: 1) as peaking generation on a simple time dispatch in which it is assumed to run for 7 hours from 3:00 PM onward each day; 2) as baseloaded CHP (running continuously).

The late afternoon peaking dispatch characteristic was selected to cover Alameda P&T's peak load much of the year. It is assumed that if it were CHP generation, there would be some thermal load to satisfy and a certain minimum number of hours of operation would be required. We acknowledge that it might be impractical to operate the generation in this manner because one can never guarantee that thermal demand will correspond to the electrical demand. We assume that anyone installing CHP generation would want to take advantage of the efficiencies possible in serving the thermal load. This case was simulated simply to see what would happen if the generation could be dispatched in this manner, which has the possibility of benefiting the distribution system without having to run all day. Figure 46 shows the simple dispatch characteristic and Figure 47 shows the impact of this characteristic on the assumed Alameda P&T load shape. By comparing Figure 47 with Figure 43, one can see the predicted impact of installing 8 MW of CHP.

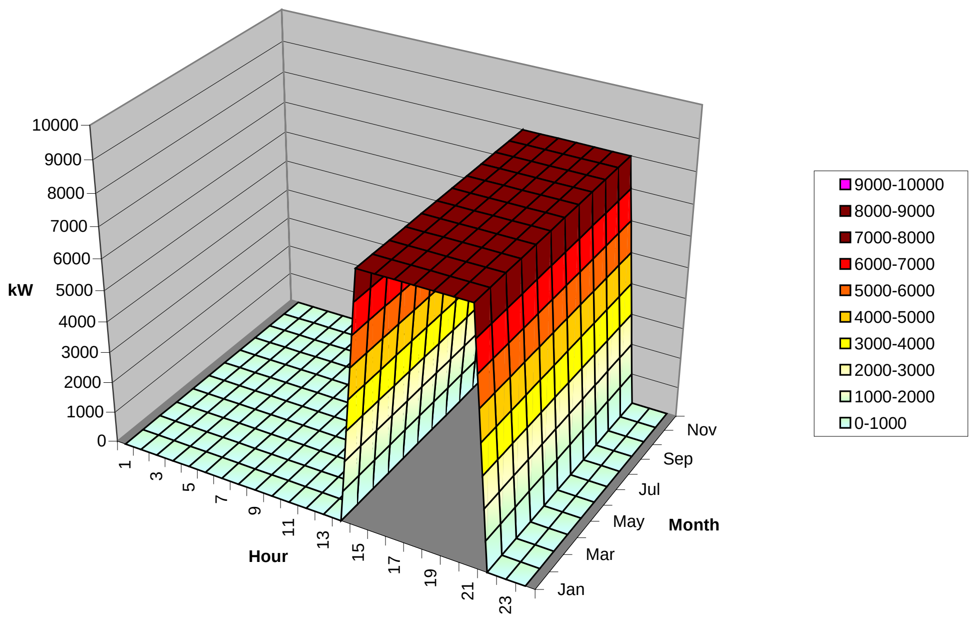


Figure 46: Dispatch Shape Assumed For 8 MW CHP Generation Operated As A Late Afternoon Peaker.

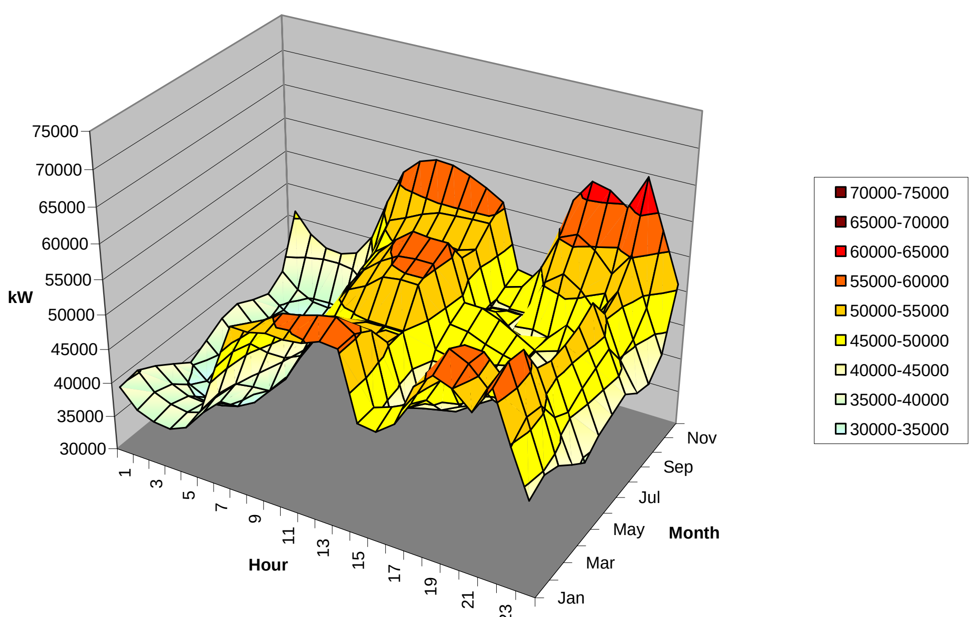


Figure 47: Impact On Area Load Shape As A Result Of 8 MW RDG Operated As A Late Afternoon Peaker. (Compare With Figure 43.)

The amount of generated energy required to produce this effect may be estimated simply by multiplying:

$$8{,}000 \text{ kW} \times 7 \text{ hr} \times 365 \text{ days} = 20{,}440 \text{ MWh}$$

The estimated possible savings in demand and losses were shown above in Table 17 through Table 19. As shown in Figure 48, this simple 7-hour peak block dispatch matches the loading better on some days than others. This 7-day sample is taken from a period during the winter close to the occurrence of the annual system peak. The addition of the 8 MW peaker generation reduces the magnitude of second peak (December) down to approximately the same level as the first peak (February). This chart suggests that this same benefit could be achieved by delaying the CHP unit's ON time to approximately 5 PM on most days. However, to cover the entire peak, the generation would have to operate from approximately noon until about 10 PM. This is more likely to be economical if there is a good match to thermal demand.

The other way to evaluate this simulation is to consider the purpose of the generation. In this case, it is simply to reduce the peak level. In this evaluation, the potential CHP benefit would be ignored. To reduce the peak load to 55 MW, or approximately the level of the first peak, would require a minimum of 2,260 MWh operating approximately 490 hours per year.

If the CHP generation were to run continuously, the total demand is reduced a little more than 8 MW each hour of the day (Figure 49). At peak load, the 8 MW of generation results in a demand reduction of 8.56 MW, with the additional 560 kW coming from the reduction in losses. In contrast, running the generation as a late afternoon peaker under simple time control results in slight misalignment with the peak demand on some days. This occurs in the winter evenings when there are still high loads after 10pm. During these hours, the peak demand is approximately 3.6 MW less than the overall annual peak. Of course, this might be corrected with more intelligent control coordinated with the Alameda P&T load levels.

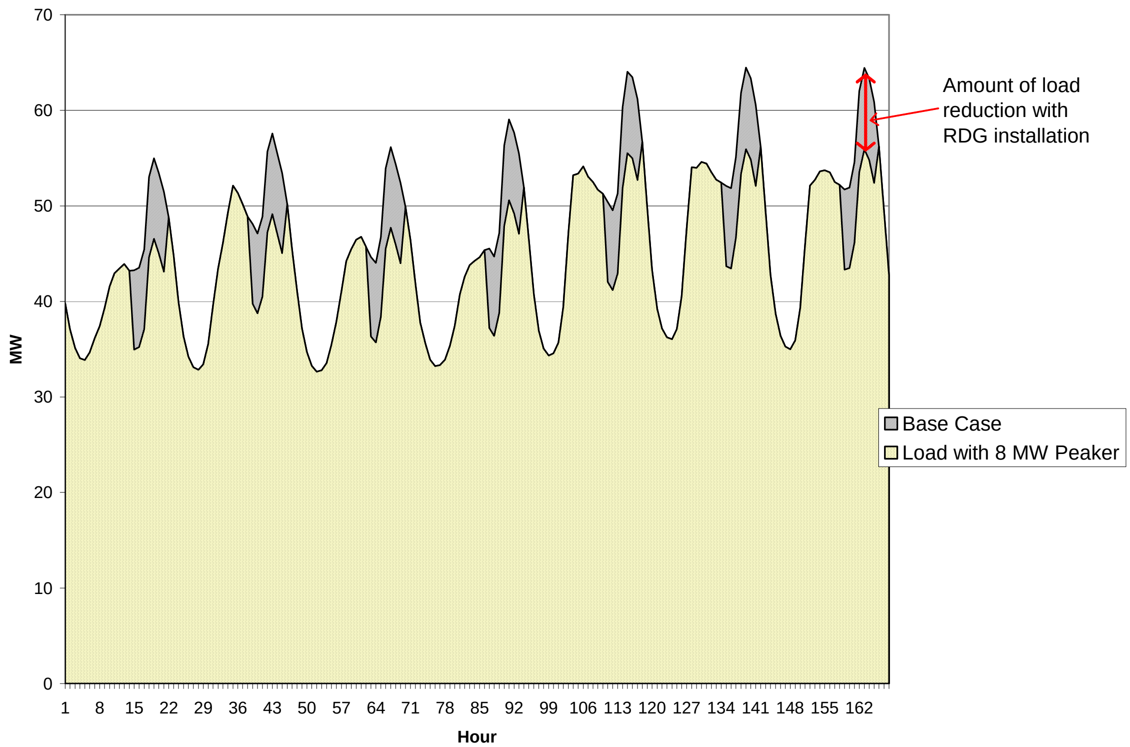
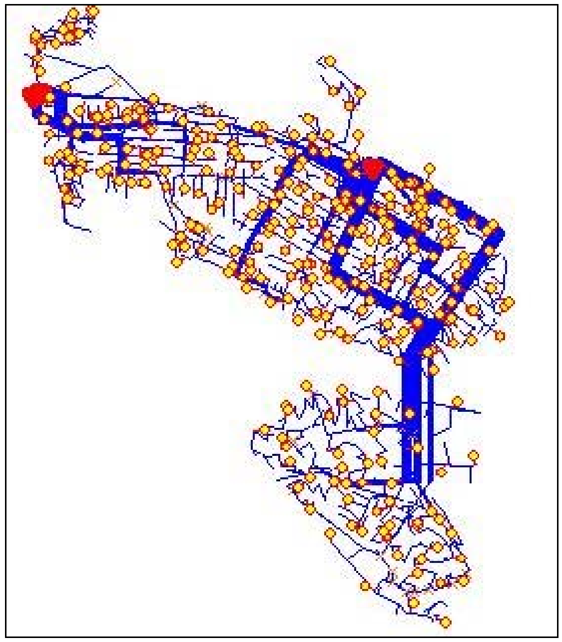


Figure 48: Impact Of 8 MW CHP Generation Operated As Late Afternoon Peaker (3 – 10 PM) On A Typical 7-Day Load Profile During Winter Peak Loading.

Running the hypothetical CHP generators continuously saves 33% in peak losses and 44% of the annual losses. This ratio is somewhat unusual (compared with the other cases). The unusually high savings in annual distribution losses is due to the assumed favorable siting of the generators with respect to losses. The losses in some of the distribution feeders are virtually eliminated at minimum load through CHP unit installation.

This finding simply confirms the mathematics of the algorithm for selecting the optimal generator locations. 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 3.7% of the generated energy goes toward loss reduction.

One should keep in mind that the model considers only primary distribution system losses. These losses are relatively low in the Alameda P&T system compared to those of other utilities. There are likely an equal 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 for the utility managers. 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.



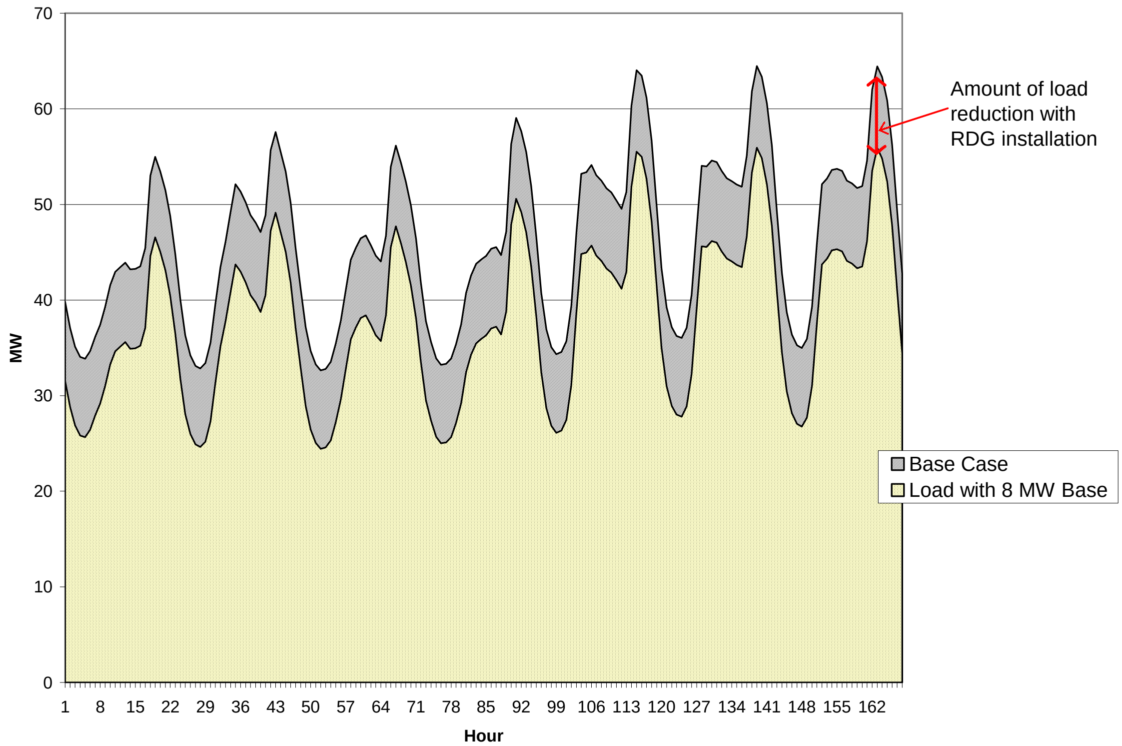


Figure 49: Impact Of 8 MW CHP Generation Operated As Baseload On A Typical 7-Day Load Profile During Winter Peak Loading.

4.3.2. Photovoltaic Characteristic

For this case, we assumed that 2 MW of photovoltaic (PV) generation is distributed approximately uniformly over the system proportional to load. The specific assumed locations are shown in Figure 50. A uniform distribution should yield a good estimate of the maximum capacity and loss reduction benefit possible from this type of generation.

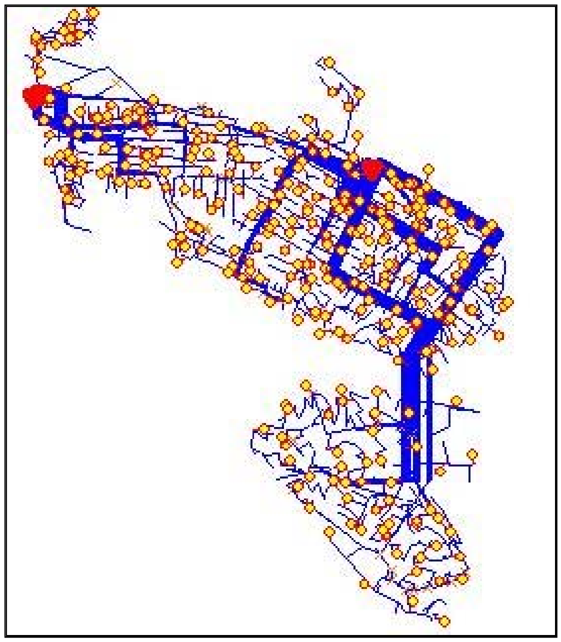


Figure 50: Assumed Locations For 2 MW Of PV Generation

For the photovoltaic characteristic, metered output from a nearby photovoltaic installation was assumed. The load shape for this data is shown in Figure 51.

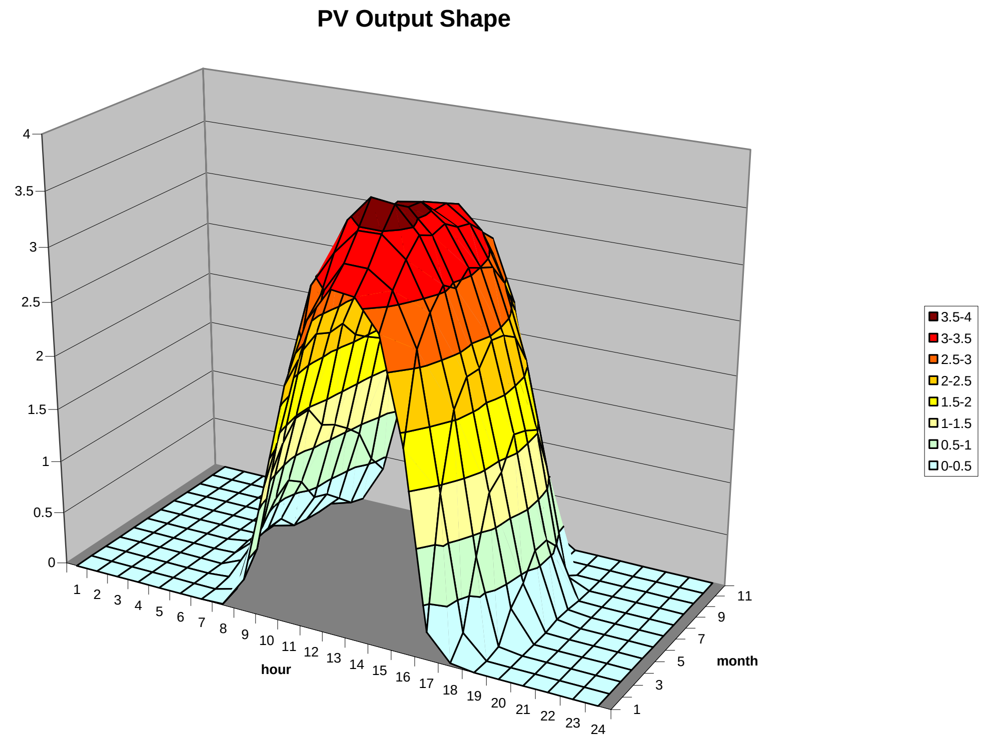


Figure 51: PV Output Shape

Figure 51 shows that PV output is consistently good in mid-day hours, even during the winter months. January output for the hour from noon to 1:00 p.m., for example, is almost 90% of that in June. However, PV output does not correspond well with Alameda P&T's overall load shape, limiting the value of PV as a deferral mechanism for distribution investment. Figure 52 shows another view of the lack of correspondence between PV output and Alameda P&T's load shape.

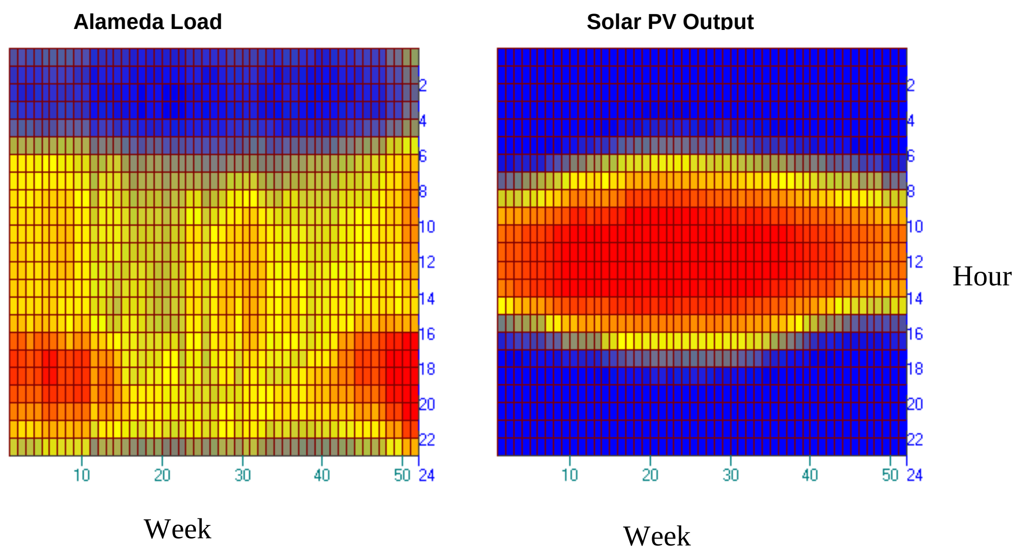


Figure 52: Side-By-Side Comparison Of Alameda P&T Annual Load And Solar Output Contours.

Figure 53 illustrates the impact of the PV generation on the total system demand for a typical 7-day period in the winter. As can be clearly seen, the peak impact does not correspond with system peak and is insufficient to make a significant impact.

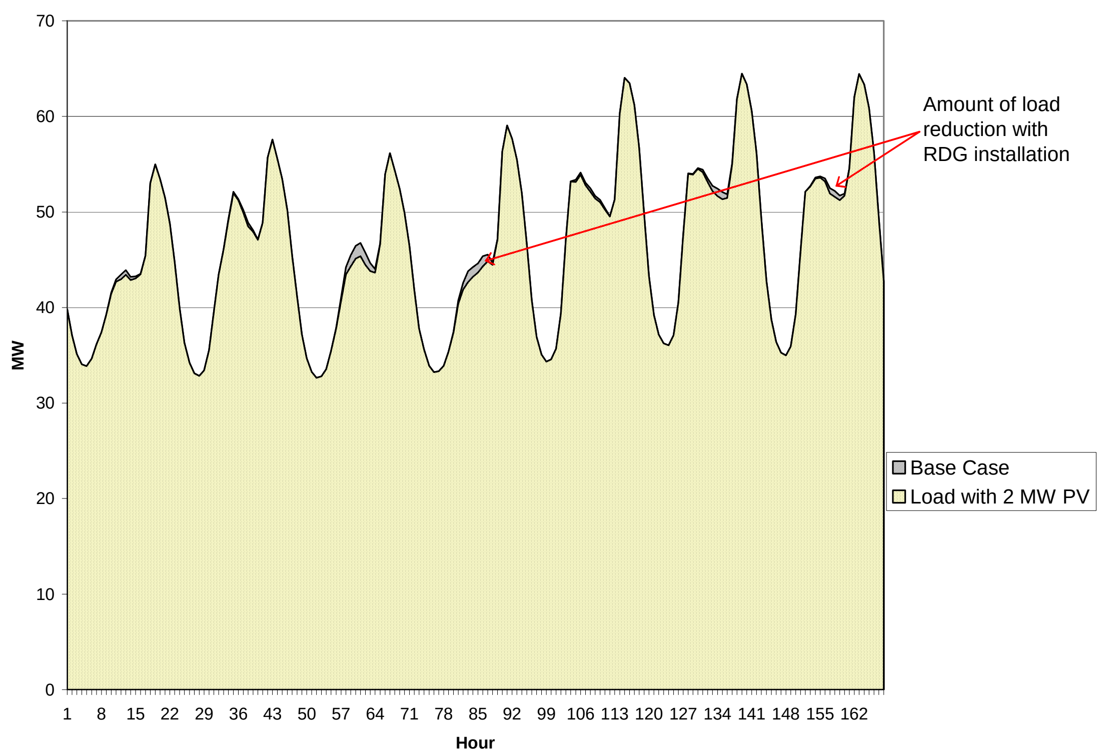


Figure 53: Impact Of 2 MW PV On Typical 7-Day Load Profile During Winter Months.

The impact on peak demand and losses of the PV system is decidedly mixed (refer again to Table 17 through Table 19). In this case, 3% of the energy generated goes toward reducing annual losses, which is a relatively good percentage on this system. This is due in large part to the assumed uniform distribution throughout the system. When the generation is available it is quite effective. This is confirmed by the purchase power savings for this case. The savings are 103% of the generated energy. However, the PV generation contributes nothing to the reduction of peak demand and peak losses because it is not available when the peak occurs.

4.3.3. 20 MW Baseload Generation Connected to Bay Farm Island

For this analysis, the 20 MW of generation is assumed to be located within a few miles of the interconnection point on Bay Farm Island (Figure 54) and to operate as baseloaded generation. Therefore, it reduces the total system demand by approximately 20 MW throughout the year. This is illustrated for the same 7-day period in the winter that we used as an example in the other two cases (Figure 55).

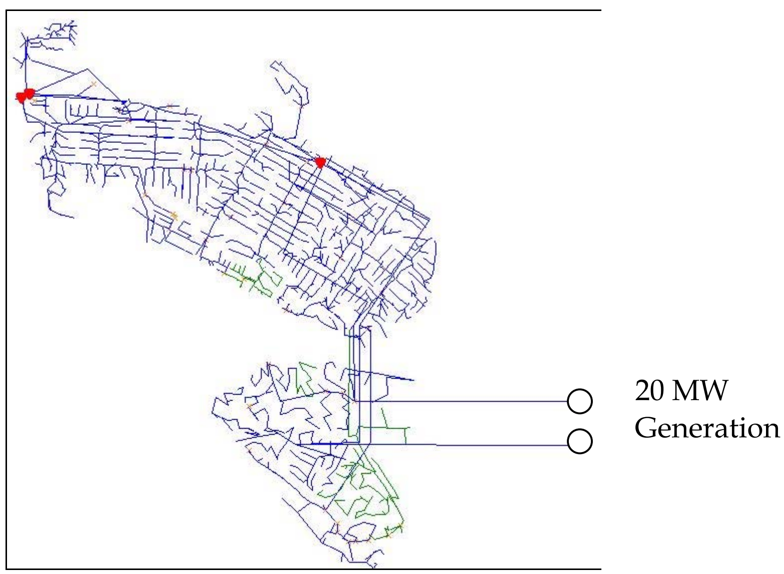


Figure 54: Assumed Locations For Interconnection Of 20 MW Generation Into Bay Farm Island (12 Kv Option)

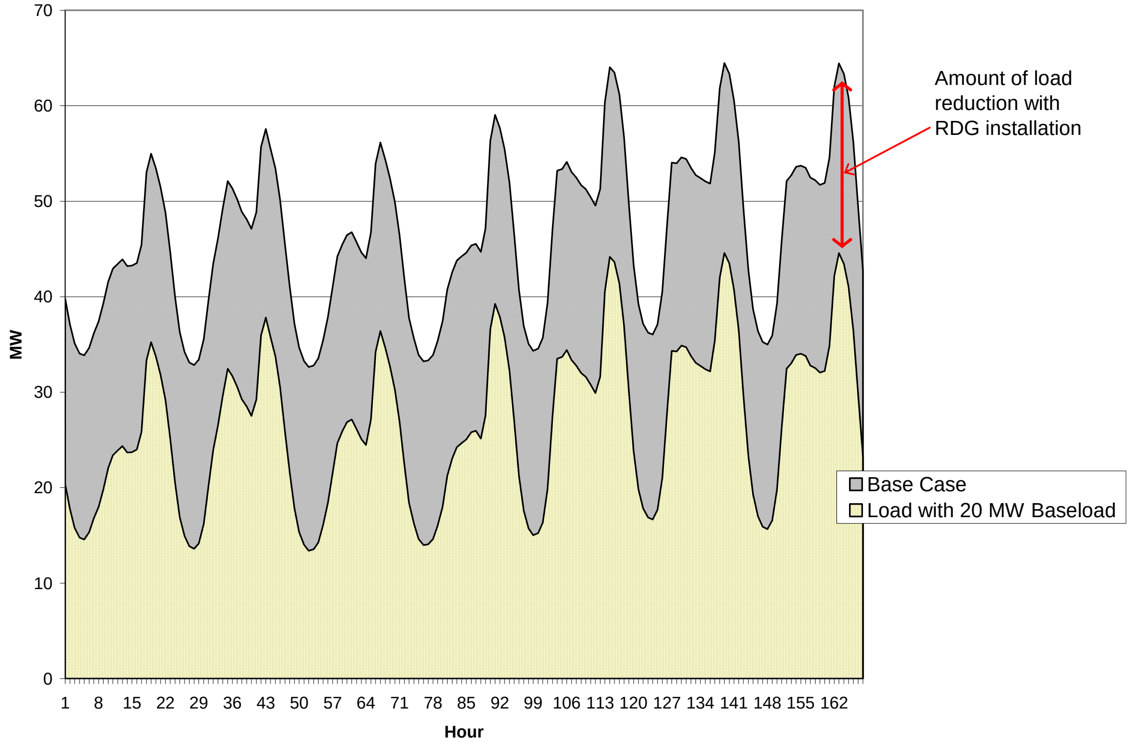


Figure 55: Impact Of 20 MW Baseloaded Generator On A Typical 7-Day Alameda P&T Load Profile During Winter Months.

We have observed what is possible if baseloaded generation were sited for optimal loss reduction. The reduction in purchased power would be approximately 104% of the local generation. However, this case is not as beneficial because the generation location, while good for Bay Farm Island, is not beneficial to the entire system with respect to losses.

If we assume that 20 MW can be delivered to the interconnection point (ignore delivery losses), the generation offsets purchased power approximately 1:1. However, if we assume that the plant produces 20 MW, and then subsequently must be delivered to the interconnection point, then approximately 1 to 3% of the 20 MW generated is lost during transport from the generation location to the interconnection point. Two possible options were considered for interconnecting to the system.

4.4. Load and Resource Summary

If the generation is sited particularly well, one can expect a boost of 3-4% on the Alameda P&T system due to the reduction in losses while the generation is in operation. The 20 MW baseload plant to serve load on Bay Farm Island works out to approximately break even in this regard if we ignore delivery losses. Including delivery losses in the interconnection cables, there is a net loss increase of 1-3% over the present case and the RDG bonus is not achieved. The proposed system reduces losses considerably at peak load, but actually increases average losses slightly when the entire year is considered. This is due to the higher average current levels, although the net power flow is reversed in the two existing feeders to Bay Farm Island.

These findings basically indicate that there are no big surprises expected for the proposed generation. The change in power demand from the PG&E system 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. Some highly constrained systems exhibit gains of 15%, or more, at peak load when the first increment of RDG is added. The maximum possible here would appear to be about 7% at peak, with an average 3-4% over the year.

5.0 Reliability Analysis

5.1. Engineering Reliability Analysis Overview

This chapter presents the results of an analysis of the impact of distributed resources (DG) and renewable distributed generation (RDG) on the reliability of the Alameda Power and Telecom (Alameda P&T) system. A particular emphasis was given to renewable technologies.

The existing Alameda P&T system has ample capacity for the present peak load of nearly 70 MW. The system is relatively compact with the exception of the feed to Bay Farm Island, which is electrically twice as far from a substation as most of the rest of the system. Much of new load growth is expected to come from Bay Farm Island. The system can withstand a major substation outage based on transformer capacity alone. However, it may not be possible to deliver adequate power to the extremities because of distribution constraints. This is one problem that might be addressed by distributed resources.

The benchmark generation proposal is a 20MW baseloaded plant powered by a renewable fuel and located on or near Bay Farm Island. This will supply present and future needs on the Island and supply some of the load currently fed off Jenney Substation. The engineering screen indicated that interconnecting such a facility to the existing 12 kV feeders is technically feasible, although some changes are likely required to correct for voltage regulation and increased fault current levels. These changes are not major.

This proposed RDG system was compared to the existing case and two reference cases: 2 MW of solar photovoltaic (PV) RDG uniformly distributed throughout the system and a DR case where 8 MW of CHP generation is assumed to be sited for optimal impact on loss reduction. The latter case was studied as both peaking and baseload generation. The reference cases are used to aid in understanding the behavior of the system and to establish points of reference for evaluating the proposed RDG system. The Engineering

Screening Analysis Chapter beginning on page 39 described these cases and evaluated the engineering feasibility of each.

The analysis shows that the proposed plant can have a positive impact on reliability, but that impact is relatively small at present loading levels. Reliability impacts will likely not be a determining factor in the economics of the project. There will be increasingly more value in the future as load grows, particularly, the load on Bay Farm Island.

The 8 MW CHP generation reference case proves that a substantial impact on reliability is possible if one were to have complete freedom in siting and sizing generation. This case was considered in two different ways:

1. As baseload generation running 24 hours per day,
2. As peaking generation running 7 hr per day from 3:00 PM onward.

CHP applications would have to be coordinated with the thermal demand of the load and may or may not align with these assumptions. Even this typically effective application of DR has relatively low economic value, a reflection of the fact that the Alameda P&T distribution system currently has excess delivery capacity.

To have the most value to the reliability of the distribution system, the distributed resource must be able to contribute at the time of the system peak load when loading levels might limit reconfiguration options. There are two peaks in the daily load cycle, the larger one generally occurring in the early evening hours. The Alameda P&T peak load is reached during the Winter months. While such renewable generation as solar PV has some benefit for the first peak, it is ineffective against the main peak. The Alameda P&T system is most at risk of not being able to serve the load in those peak hours. At other times, there is likely to be sufficient capacity to withstand a single contingency failure. To provide reliability improvement, the generation would have to be available in those few hours of risk.

The basis for assessing the impact on reliability of a proposed RDG option is the amount of capacity released in the power delivery elements (lines and transformers) in the normal system configuration. This is determined by annual simulation (8670 hourly load intervals). Only loading of more than 50% of maximum capacity is considered for capacity release. Reliability of distribution systems is largely an issue of having enough excess capacity in the appropriate location to cover for failures of components. Below 50% loading it is assumed that there is no need for released capacity. The losses also have a strong correlation to the capacity of the system. Both the energy losses and the amount of energy served above engineering limits are computed for the base case over a range of load and then compared with the same quantities computed for each RDG option considered. This is a measure of the risk of not being able to serve the load. The increase in capacity enabled by a particular option is then judged on the basis of equal risk.

If one were able to distribute 2 MW of solar PV uniformly across the system, an effective capacity improvement of approximately 500-700 kW could be achieved considering reliability. The assumed solar PV option is very effective during the mid-day hours and contributes a relatively large portion of the total installed capacity toward released capacity in the power delivery system. This reduces the risk of unserved energy at those times. However, this option is limited in terms of reliability by not being able to contribute at the hours when the system is most vulnerable. Without storage, PV generation is not an effective technology to provide reliability assistance to Alameda P&T.

The 8 MW CHP generation reference case is reasonably effective by these measures. Assuming the load grows uniformly across the Alameda P&T system, the load can grow by nearly 6 MW before there is the same risk of unserved energy as the base case. This case illustrates that if there were the option to site generation where it is most needed, substantial capacity gains can be made. By siting generation where it is most effective for losses, this case automatically addresses many capacity constraints. Such constraints are related to current levels and can often be correlated with losses. If the generation is running continuously, it is quite effective against losses, as might be expected.

The proposed 20MW baseloaded RDG plant produces mixed, but interesting, results by these measures. This is a large amount of power to be injected into the system and one might expect significant increases in capacity. It does release a substantial portion of the existing capacity in the two 12 kV feeders used to deliver power to Bay Farm Island. In fact, much of the time the net power reverses direction on these feeders and they would serve to deliver the excess power from the assumed Bay Farm Island interconnection to the rest of the system through the Jenney Substation. However, because only the portion above 50% capacity is assumed to count toward a reliability improvement, this analysis shows only modest improvements. There is only a relatively small reliability benefit in terms of power delivery to the system as a whole at present load levels. The analysis shows effective incremental capacity increases of less than 1 MW at present loading. This small gain reflects the fact that the impact is only in one part of the system where it is less needed and the loading of the remainder of the system is unchanged. Therefore, the contribution of the proposed plant to the reliability of the Alameda P&T power delivery system is relatively minor at present. It frees the capacity of feeders 4212 and 4214 to be used to assist in serving other parts of the system in the event of transformer failures at either of the two major substations. It would be most helpful if both transformers at either substation where out of services. With only one substation transformer out of service, the generation is useful, but the need is not as great.

As load grows in the future, this generation would have a greater proportional impact on improving the reliability of the power delivery system. Load growth is expected on Bay Farm Island. When it occurs, the contribution of the proposed plant to system reliability is of more value. The simulations indicate that power delivery constraints may arise in other parts of the system as the load grows. These must be addressed by means other than those considered here. One possible means to better involve the proposed renewable generation in the solution is to add another feed from the Bay Farm Island interconnection to the main part of the Alameda system.

20 MW of generation can help cover a major failure at the Jenney substation such that neither transformer is available. This is a very unlikely double contingency that utilities generally do not plan to cover. About half the load from the Jenney bus could be shifted

to the Cartwright substation. Likewise, the generation could help cover a transformer failure at the Cartwright substation by appropriate load shifting. The entire present load of Bay Farm Island could be served with 20 MW generation, which covers the failure of the channel cables. However, there are four cables there already and it is not likely that more than one would fail at a time. There is some value to having the generation to cover these rare contingencies, although it is likely of secondary importance in the justification of the generation.

The analysis does not consider the impact of the proposed system on transmission system reliability. However, it may be valuable to cover loss of transmission or a curtailment in transmission supply with this generation.

If the generation technology drives rotating alternators, it could possibly supply the 14 MW Bay Farm Island load separately in an emergency. Therefore, the reliability of the supply to Bay Farm Island is improved by essentially providing fully redundant backup generation. In analogous situations in commercial and industrial loads, add fully redundant backup generation typically adds an order of magnitude improvement in the availability index (one more "9": e.g., 99.99% to 99.999% availability). Technologies that require inverters make the idea of serving as backup generation more problematic. While the ability to serve as backup generation may come for "free" with alternators, there is usually substantial extra cost that may not be justifiable when inverters are used.

The ideas for the proposed plant are mostly focused on modular technologies in which there would be a number of small generating units. This is an inherently reliable design that should make most of the plant capacity available at all times. However, the reliability of the delivery system should be considered. This might dictate whether one cable or two separate cables are used to connect the generation to Bay Farm Island. Reliability of supply to other parts of the Alameda P&T system is essentially unchanged from present values.

The power quality while hypothetically supplying Bay Farm Island separately, as an electrical island, should not be expected to be as good as running while interconnected with the PG&E grid. Although the nameplate capacity might be sufficient, the system is inherently weaker. Without adding expensive control devices, issues such as voltage regulation, harmonic distortion, load switching transients and system stability would likely be worse. Therefore, this configuration should be considered only in an emergency and the generation capacity de-rated. A rule of thumb to ensure adequate power quality is to limit the load to between 50% and 70% of the generation rated capacity. Of course, this is dependent on the type of load served. If even a weak connection to PG&E can be maintained, it is more likely the full nameplate capacity can be exploited with acceptable power quality.

5.2. Reliability Evaluation

The reliability impact of small generation on the power delivery system is an area of continuing research. DG proponent literature will claim a reliability benefit, but there is not agreement over how to define the benefit (see References **Error! Bookmark not defined.** - **Error! Bookmark not defined.**). The benefit is quite different depending on perspective. Utility engineers are reluctant to provide credit to RDG for improving the reliability of the power delivery system. They would argue benefits of small generation are too small to make a difference in investment decisions and that RDG 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 RDG can experience an improvement in reliability if the RDG 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 RDG. 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.

RDG can increase the capacity of the system and there is an intrinsic relationship between capacity and reliability. To evaluate reliability impacts of RDG, we compute the additional load serving capacity made possible by the addition of RDG. 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 RDG 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 RDG alternatives. In this particular study, we analyzed the main proposed case and compared it to two reference cases that have more predictable characteristics.

5.2.1. Basic Concept

Figure 56 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 assumes 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 Alameda P&T 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 RDG 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.

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 computed 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 determined the degree to which a plan impacts the whole system under study. While there may be great impact on one feeder, that may or may not result in a significant impact on the whole system.

The basic method for interpreting the results is illustrated in Figure 56.

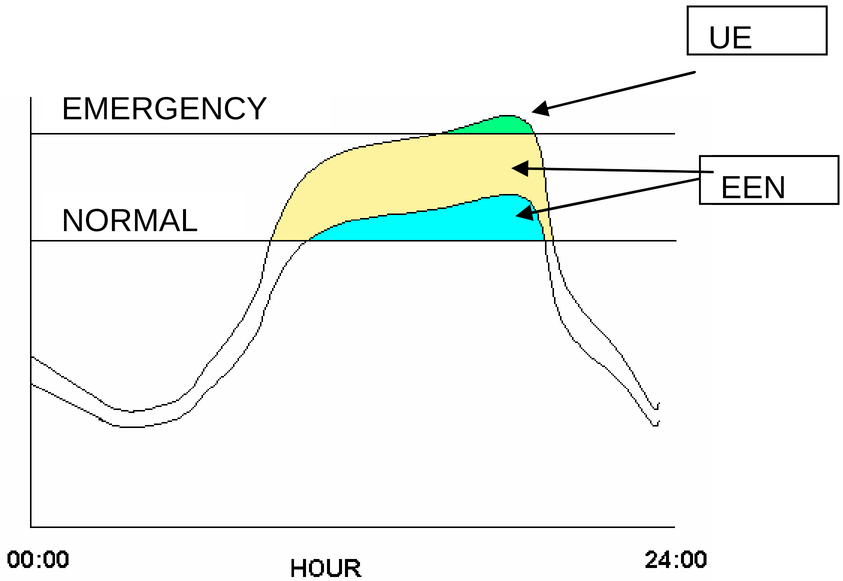


Figure 56: Basic Concept Of Unserved Energy (UE) And Energy Exceeding Normal (EEN) For Evaluation Of Capacity.

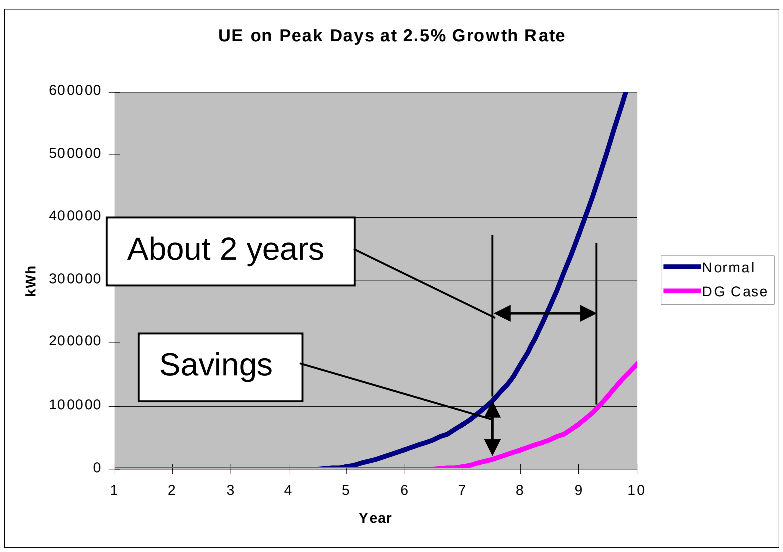


Figure 57: Evaluating The Impact Of RDG On The Power Delivery System Capacity.

Figure 57 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 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/kW 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 RDG option increases to the same value as the base case approximately two years later. Therefore, we can conclude that the RDG 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 are economic compared to the cost of operating the generator, then the RDG option would be a good alternative to new feeder and substation construction. This is a very useful analysis for situations where:

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 until the growth is more certain,

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 years. Then the horizontal difference between the curves represents the incremental load-serving capacity the RDG adds to the system. This is becoming a popular measure of the effectiveness of all types if RDG and is the method chosen to compare alternatives in this report. In terms specific to this report:

Given a particular RDG proposal, how much more load can be served by Alameda P&T at 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 RDG 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 is load served is more closely related to the size of the RDG, assuming the RDG is an appropriate location to be of assistance. Sometimes, the increase in load allowed is greater than the RDG size, if it is in a particularly good location. At other locations, the benefit can be a small fraction of the RDG capacity.

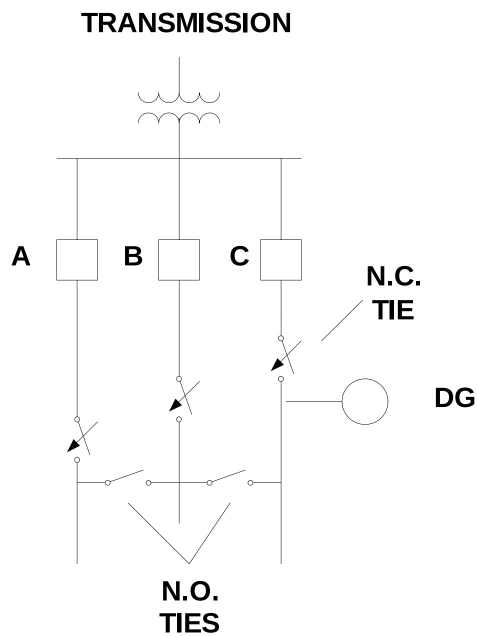


Figure 58: How DG Might Affect Distribution Reliability.

If we define the system as consisting of more than one feeder, the net gain is often much less than the RDG size even if it is in a good location for one feeder. A specific generator provides capacity to only one of those feeders. However, if the RDG 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 58. Consider these cases:

1. If the transmission system goes down, only a small amount of load can be served: 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 load because part, or all, of its load is load-serving capacity has been 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 that is taken when either the utility is willing to undertake more switching options or accept more risk of a 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 emulated. 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 Alameda P&T system an urban setting where this philosophy might well apply, but this value allows for improved resolution in the computing of the EEN values. This provides better comparisons of the alternatives.

5.4. EEN Evaluation

For each of the cases described in the following, the total load on the Alameda P&T system was grown from its present peak of almost 70 MW to approximately 88 MW. The evaluation was not carried out farther because the model indicated that some reconfiguration or rebuilding of feeders might be necessary to keep voltages within the proper range in parts of the system not directly involved in the analysis.

5.4.1. Base Case

To compute EEN values, the Normal rating of the power delivery elements was arbitrarily 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 simulating each separately. The reliability evaluation values are computed in one pass. The goal is to develop EEN and loss curves for the various options. These are then compared to determine the effective additional capacity added by each option compared to the Base Case.

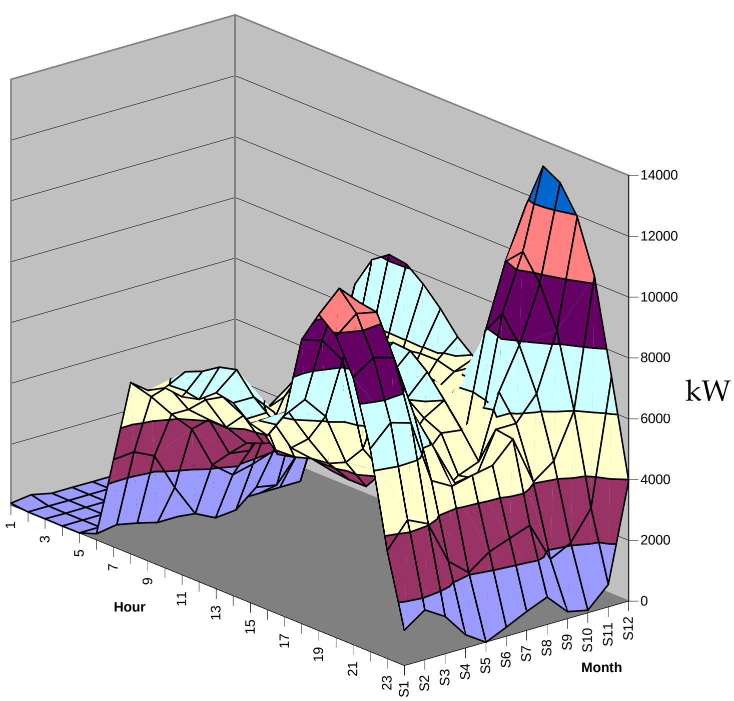


Figure 59: Shape Of Peak Hourly EEN For Base Case.

The EEN was computed for the Base Case without any generation. Figure 59 shows a 3-D plot of the annual shape of this quantity. Note that the EEN is zero in the early morning hours. Then the computation was repeated for two reference cases and two means of connecting to the proposed Bay Farm Island RDG. The results reflect the impact on the present Alameda P&T system.

5.4.2. Reference Case 1 (16 500-kW CHP Generators)

This case represents an idealistic scenario where a certain amount of generation is applied where it gives the greatest benefit to the system. This provides a nominal benchmark for what might be achievable.

This case was established by placing 500 kW generators at various places around the system until it appears the benefit of additional generators is declining. The main criterion for selecting the location was the kW reduction in losses at the assumed peak loading. Released kW above 50% loading was also part of the criteria, but had only a minor impact on the site selection criteria. A total of 8 MW generation was added in locations shown in the associated Engineering Report [**Error! Bookmark not defined.**]. This cuts the primary distribution system losses by nearly one third at peak load. This savings amounts to approximately 7% of the generation output at peak.

This reference case as simulated as being dispatched in two different modes:

1) As baseload generation , and
2) As a peaker in the late afternoon.

The baseload generation is assumed to be dispatchable and is running constantly. The peaker simulation assumes that the load will be dispatched on a 3:00 PM and will then run continuously for 7 hours to cover the peak. The generation is referred to here as CHP (combined heat and power) generation simply because this is the main class of RDG that might be operated in this manner. The idea would apply as well to other technologies that could be operated similarly.

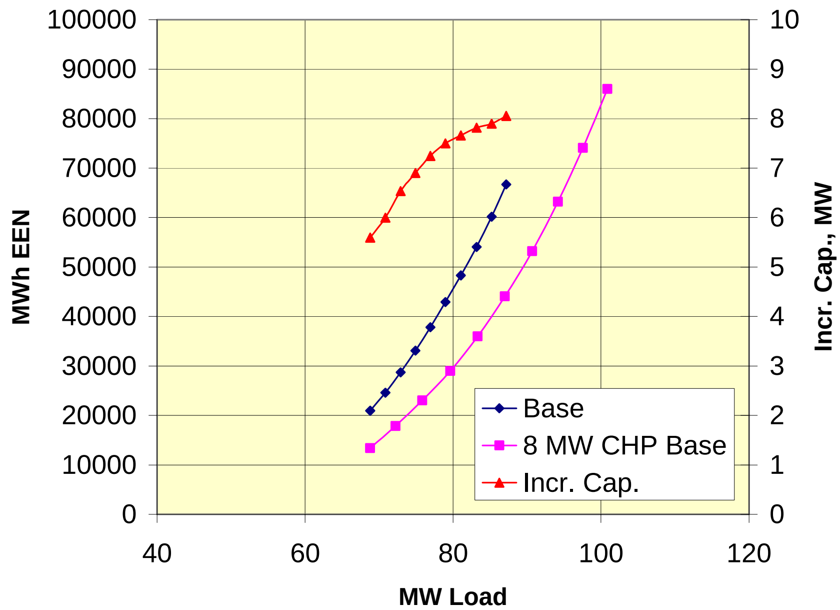


Figure 60: EEN Computed For 8 MW Of Baseload Generation Sited For Maximum Benefit To Distribution System Losses (Reference Case 1).

The EEN results for baseload cases like this reflect the maximum possible improvement in EEN for similar-sized generation operated as backup generation or a dispatchable peaker. If the RDG can be accessed on at any time, it would be available to assist with any shortfalls in delivery capacity reflected by the line ratings in the simulation as if it were online continuously. The peaker simulation reflects the improvement possible for any type of RDG technology that is able to operate *only* during the afternoon-evening peak. It simply provides another data point and reflects what would be possible if Alameda P&T were to achieve a well-placed RDG solution that offsets the peak (such as some sort of storage technology) but has limited dispatch capability.

This hypothetical CHP solution is quite effective in not only cutting the losses, but in freeing capacity in the system. It cuts the EEN approximately 36% for the present annual loading. This allows the load to grow by approximately 5.5 MW before the total EEN in the system will reach the same value as at present. As the load grows in the future, this amount of added capacity actually increases when compared to the base case (no generation) for the same loading level. This is what is indicated by the incremental capacity curve in Figure 60 (top curve, labeled "Incr. Cap."). It is simply a reflection of the fact that the EEN above 50% capacity is increasing with the load and this generator configuration is particularly useful in countering this growth. No credit is given for relieving loading below this capacity limit. For the purposes of this study, it would be said that this 8 MW of generation adds between 5.5 and 8 MW of capacity, depending on total load.

This is actually a very good result considering that the generation is confined to just one part of the system. Normally, the generation would have to be spread out over a somewhat larger area to achieve this much additional capacity as the generation. In this case, it is likely simply a reflection of the more constrained loading of the delivery system to Bay Farm Island and nearby area on the main island.

The effectiveness of this case is even more dramatic with respect to the losses (see Figure 75). The load can increase by approximately 17 MW before the losses return to the levels projected for the present peak loading condition. Results like these are to be expected for generation added in locations that are near optimal for loss reduction.

Figure 61 shows the EEN results for the case where the 8 MW of generation is simulated as a late afternoon peaker.

If the generation is available only during this period, the potential reliability improvement is limited. There are other periods when there is some risk of not being able to serve the load by the measures used. Sometimes, the afternoon peak occurs somewhat earlier and the late evening peak extends a little longer than the 7 hr assumed for the simulations. Effective incremental capacity improvements would be in the range of 2.5 – 4 MW.

Incremental capacity curves from EEN usually increase to a point and then decline as constraints in other parts of the modeled system become critical and begin to dominate the EEN calculations. The fact that these curves are still on their way up is an indication that there is generally ample current-carrying capacity in the lines and transformers Alameda P&T primary distribution system. As mentioned above, it is impractical to carry the simulations to the point where this downturn might occur because the model was showing signs of low voltage. Some load transfer or feeder reinforcement would have to be done to compensate. No attempt was made to model this.

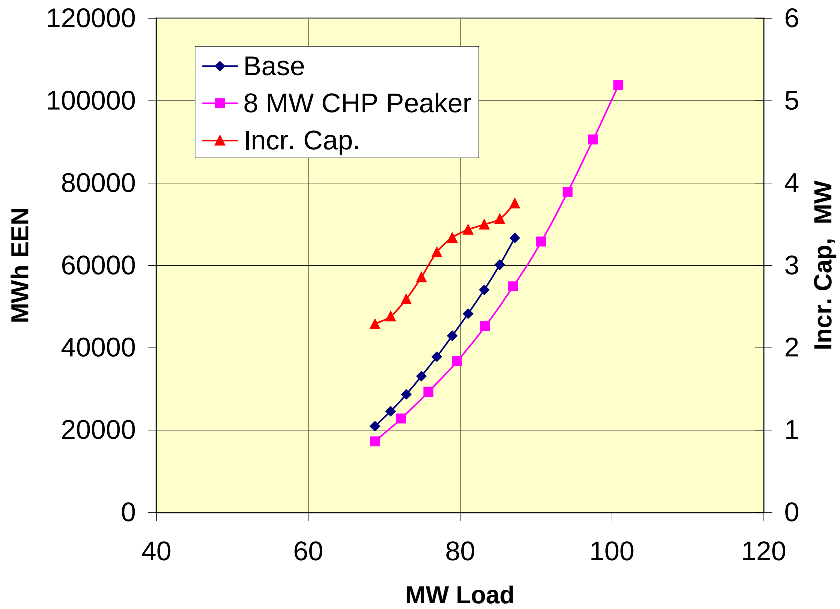


Figure 61: EEN Computed For 8 MW Of Later Afternoon Peaking Generation Sited For Maximum Benefit To Distribution System Losses (Reference Case 1).

Figure 62 shows the present annual shape of the peak hourly kW savings in EEN achieved by this generator configuration. The savings are depicted as the "dent" the generation takes out of the system base EEN characteristic (see Figure 59). Thus, the savings show up as negative on this scale. It is nearly the inverse of the base characteristic except that it is clipped. Note that there are no savings in the early hours of the morning because there is no EEN at those hours. At the peak load time in December, the generation contributes nearly 2.5 MW of the 8MW of generation to capacity release. This is another way to measure the average capacity provided by the generator that is more pessimistic than the method described above. It doesn't show 8 MW because there is no guarantee the generation will be where it is needed to compensate for a fault.

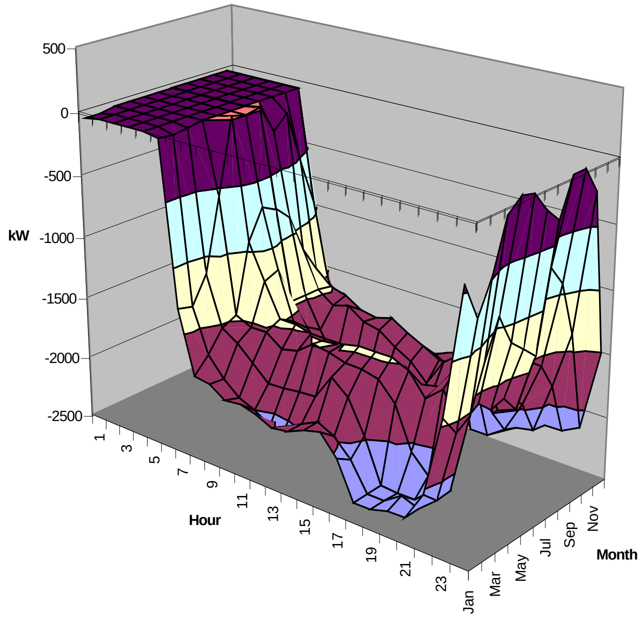


Figure 62: Depiction Of The Impact Of The Generation In Reference Case 1, Dispatched As Baseload Generation, On The Peak Hourly EEN As Compared To The Base Case.

Figure 63 shows the same plot for the RDG being dispatched as a late evening peaker as described. The peak contribution to capacity is the same as in the previous figure. However, the contribution occurs over a more limited time interval. This represents the impact of having some RDG dedicated to covering the peak, but limited to those hours of operation. The areas were the "savings" are positive represent those times when there is risk of inadequate capacity to cover a given distribution contingency.

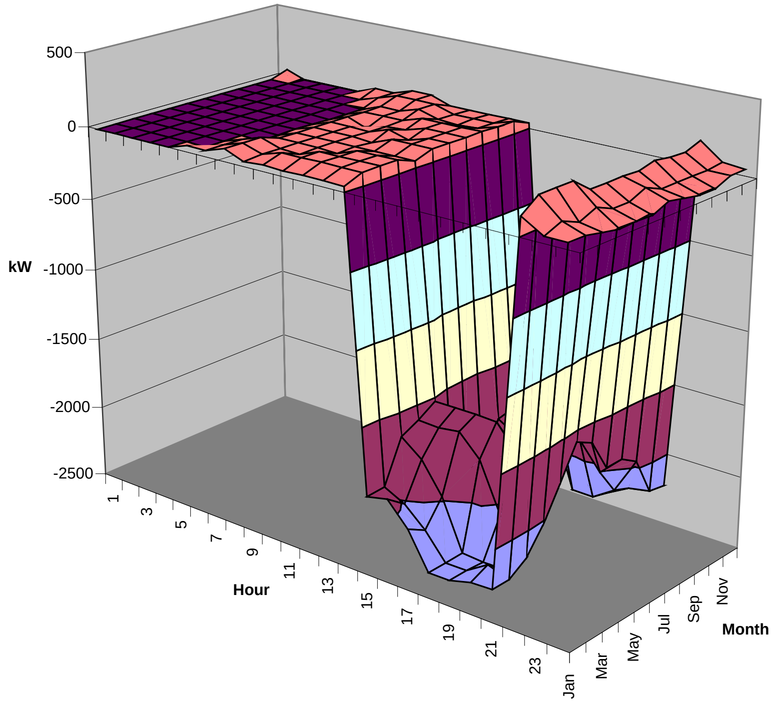


Figure 63: Depiction Of The Impact Of The Generation In Reference Case 1, Dispatched As Late Afternoon Peaking Generation, On The Peak Hourly EEN As Compared To The Base case.

5.4.3. Reference Case 2 (2 MW PV Generation)

In this case, 2 MW of solar photovoltaic (PV) generation was distributed uniformly over the system proportional to load. By uniformly distributing the generation, one might expect to see good 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.

Figure 64 shows the EEN computed for this case compared to the base case and the corresponding incremental capacity curve.

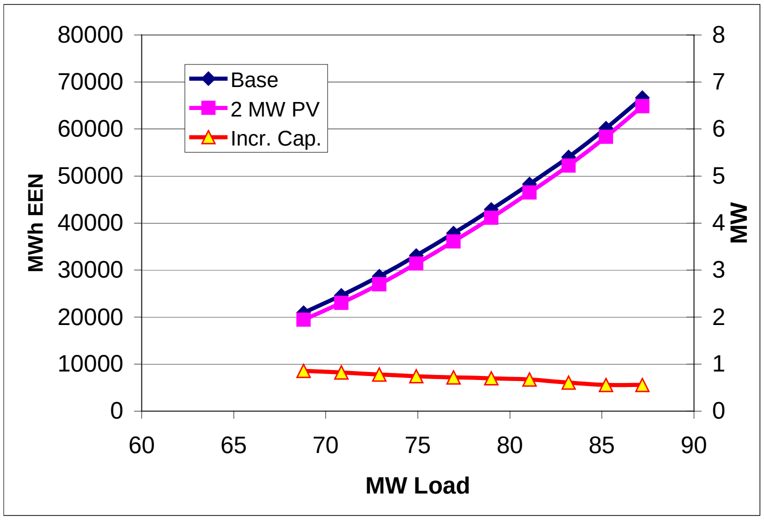


Figure 64: Capacity Increase With Respect To EEN For 2 MW Of Solar Photovoltaic Generation Uniformly Distributed Throughout The System (Reference Case 2).

There is little difference between these two EEN curves and the horizontal difference (an estimate of the incremental capacity increase) reflects this. The effective increase in capacity starts out at about 0.8 MW and *decreases* as the load grows.

The reason for this should become obvious after studying the next three figures. Figure 65 shows a 3-D plot of the annual peak kW savings, or the amount of generation that effectively contributes to the improvement in the EEN. This chart shows that the PV is very effective during mid-day, contributing at times 1.2 MW of the 2 MW of total capacity toward relieving capacity in the distribution system. Keep in mind that we are only considering lines loaded more than 50%, so some of the PV generation would be installed on lines that are not loaded this heavily. Such generation does not contribute to sufficient released capacity to significantly affect the reliability by our measure. Nevertheless, the PV generation is well-positioned by being proportionally distributed and contributes well to capacity when it can.

The larger issue with solar PV with respect to reliability is that it does not contribute any power to counter the early evening peak when it is needed most. Figure 66 shows a comparison of the daily load shape and the daily solar PV shape assumed in this study. While the solar PV curve (dashed) lines up well with the mid-day peak, it completely misses the second peak of the day. This is further illustrated on the next two figures. Therefore, if a failure were to occur during these hours, no help is available from PV generation.

The decline in the apparent incremental capacity curve as the load grows is due to the fact that the mismatch between generation and load gets progressively worse as the evening peak grows.

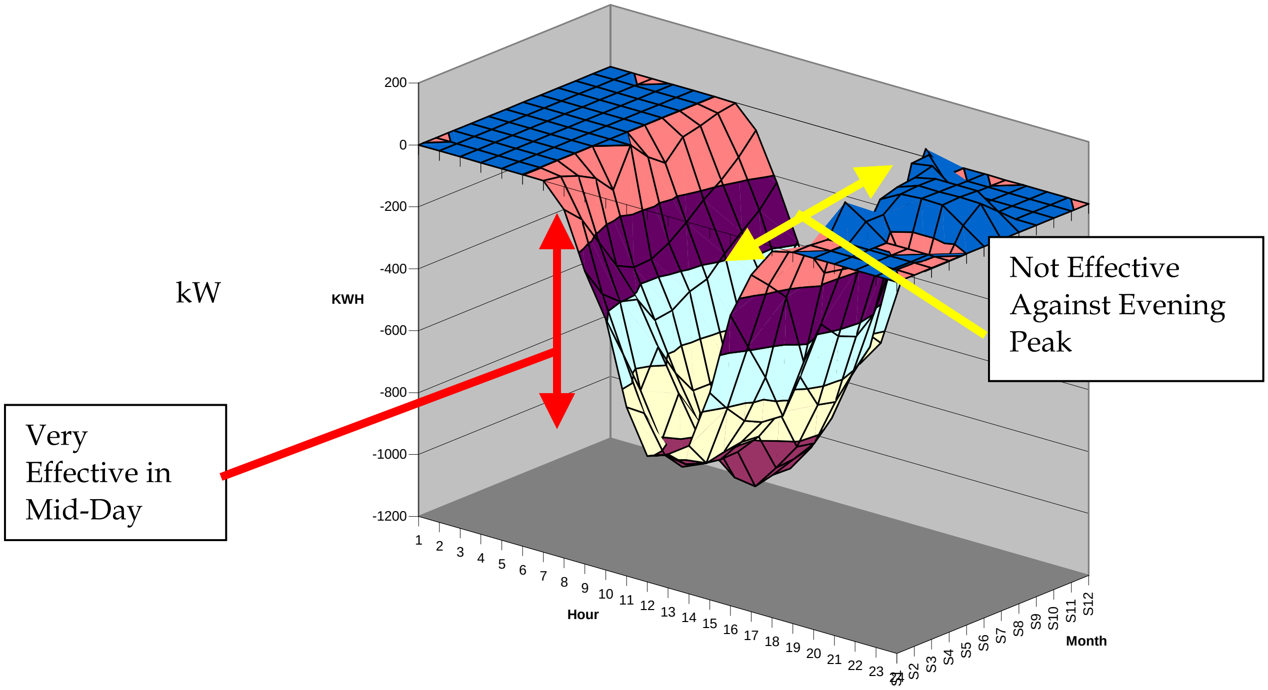


Figure 65: Depiction Of The Impact Of The Generation In Reference Case 2 (2 MW Solar PV) On The Peak Hourly EEN As Compared To The Base Case

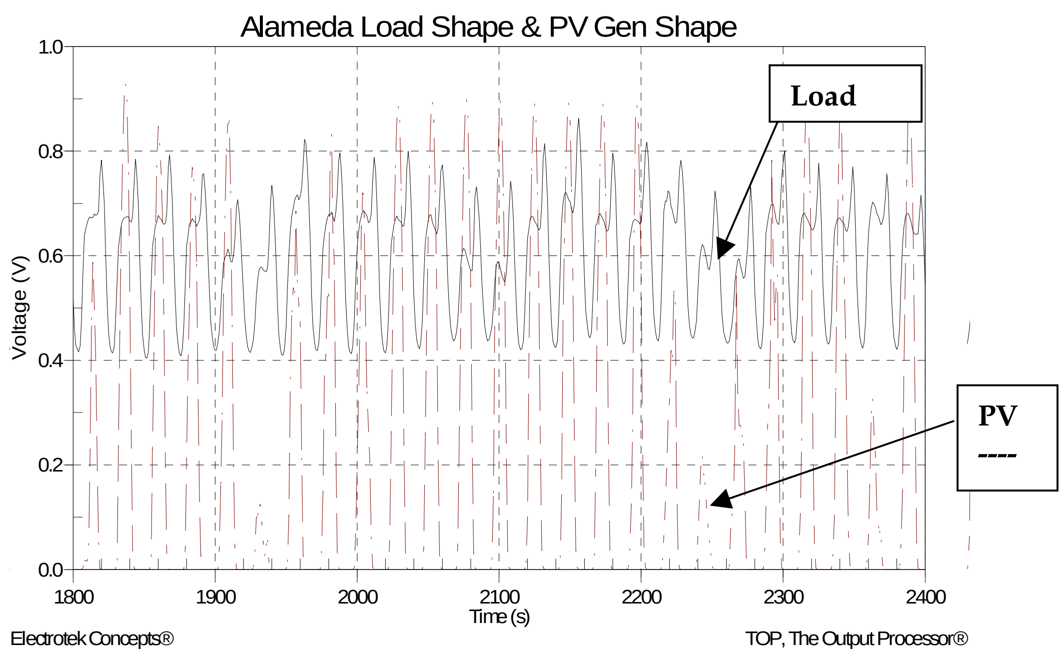


Figure 66: Comparison Of Alameda Load Shape And Assumed Output Of PV Generation.

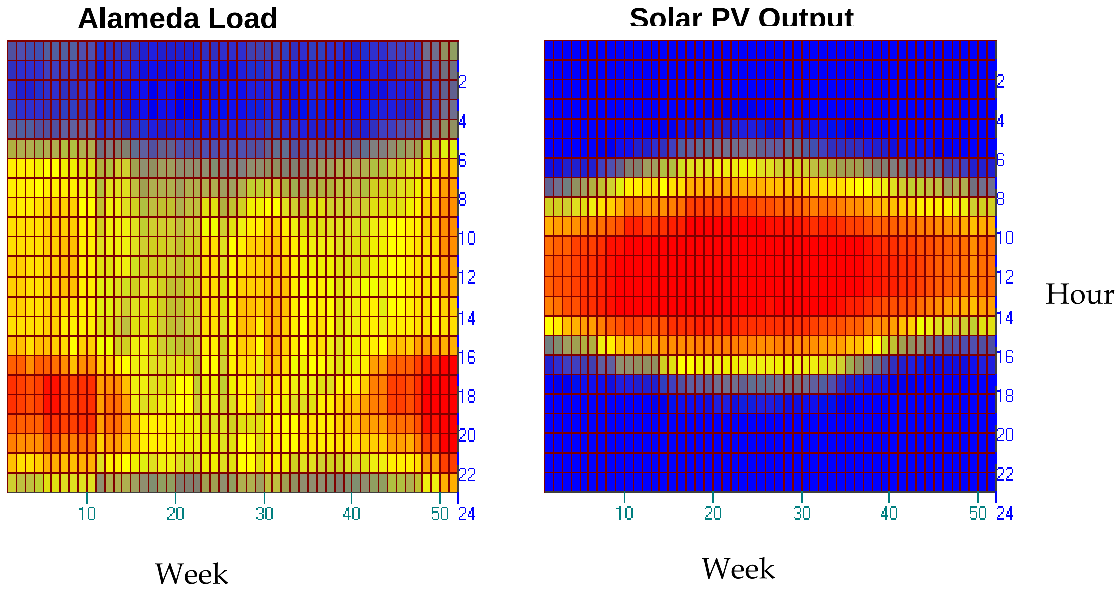


Figure 67: Comparison Of Alameda Annual Load Contour And Solar PV Annual Output Contour.

The contour plots in Figure 67 show another way to view the degree to which the solar PV output matches the Alameda load. Here, the red colors represents the peak load of power output, fading to yellow, and then blue. 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 times for load demand coincide with this production only a few times per year. Most of the peak load demand occurs later in the day and has little coincidence with the peak solar PV generation.

By covering some of the peak load for part of the year, the solar PV option gets some credit toward improving the reliability of the distribution system, but the amount is quite limited due to the nature of the generation. The declining effective capacity increase as the load grows is a result of the EEN increasing disproportionately as the load grows. Something else would have to be done to maintain the capacity of the system.

Keep in mind that this hypothetical case assumes a uniform distribution of the generation. If the distribution of PV generation is less ideal, the credit toward reliability would likely be less.

5.4.4. Proposed RDG to Serve Bay Farm Island

Figure 68 shows the comparison of EEN computed for the proposed plant options and the corresponding incremental capacity curve. Although the losses differ between these two options (see Figure 78 and Figure 79), the EEN for both cases are virtually identical. The loading on the new lines from the proposed plant to the interconnection point on Bay Farm Island is ignored. The EEN reflects only the capacity released in the existing system.

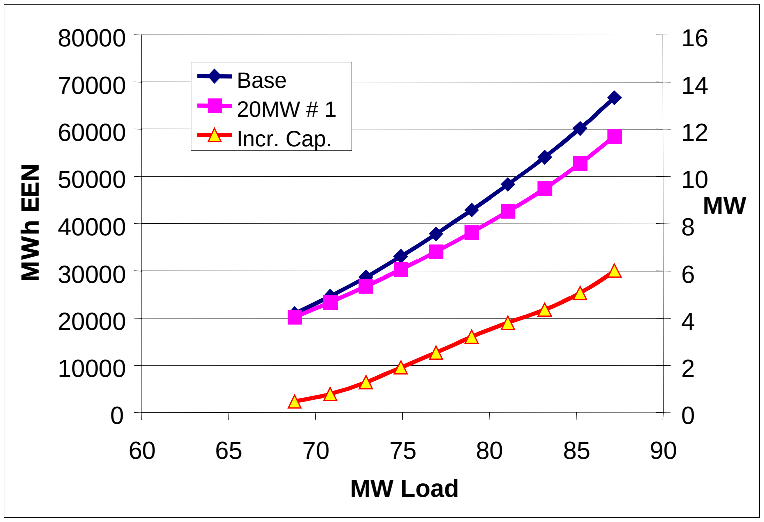


Figure 68: Capacity Comparison Of Option 1 With The Base Case (No Generation). (Option 2 Is Virtually Identical)

This chart shows some intriguing results. At the present loading of almost 70 MW, there is surprisingly little apparent benefit to having this generation. Why is this? It might seem intuitive that adding 20 MW of generation to a system with 70 MW load would have a tremendous impact.

There may very well be a great financial benefit, but the impact on the reliability of the existing power delivery system is not necessarily large – at least in the initial years. As the load grows, particularly on Bay Farm Island, the reliability benefit could become quite significant.

An understanding of this can be obtained from the next two figures. Figure 69 shows the power, kW, served above 50% line capacity in the system served from the Jenney #2 substation transformer for the peak week of the year. The area under the curves represents the EEN – the larger area for the case without generation. The generation pushes the loading in the feeders serving Bay Farm Island (#4212 and #4214) down well below the assumed Normal limit (Figure 70). However, there are other feeders served from the same substation bus. Therefore, only a portion of the EEN is eliminated and a portion remains (the smaller cross-hatched area). The difference is the benefit of the generation.

As the load on Bay Farm Island increases, the EEN in the base case increases much more rapidly than with the generation. Thus, the incremental capacity curve increases for higher loads. If the load growth stagnates on the main part of Alameda, but continues to grow on Bay Farm Island, the reliability benefit will appear to grow faster.

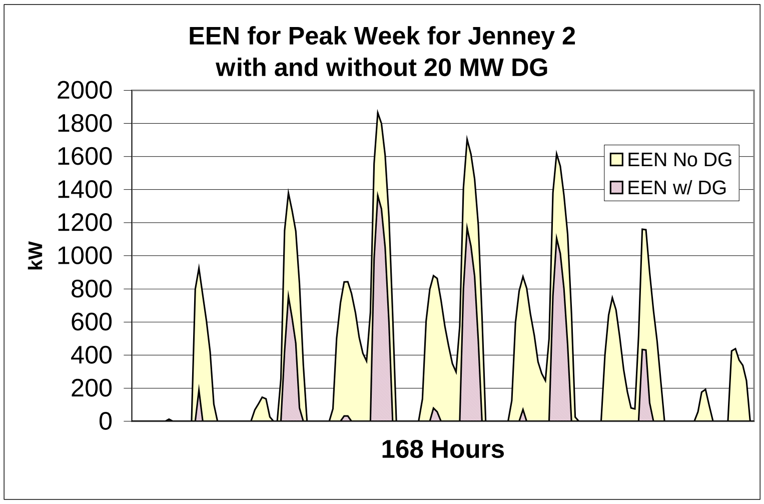


Figure 69: Comparison Of EEN Computed For Jenney 2 Substation For The Peak Load Week, With And Without The 20MW Generation From The Proposed Plant.

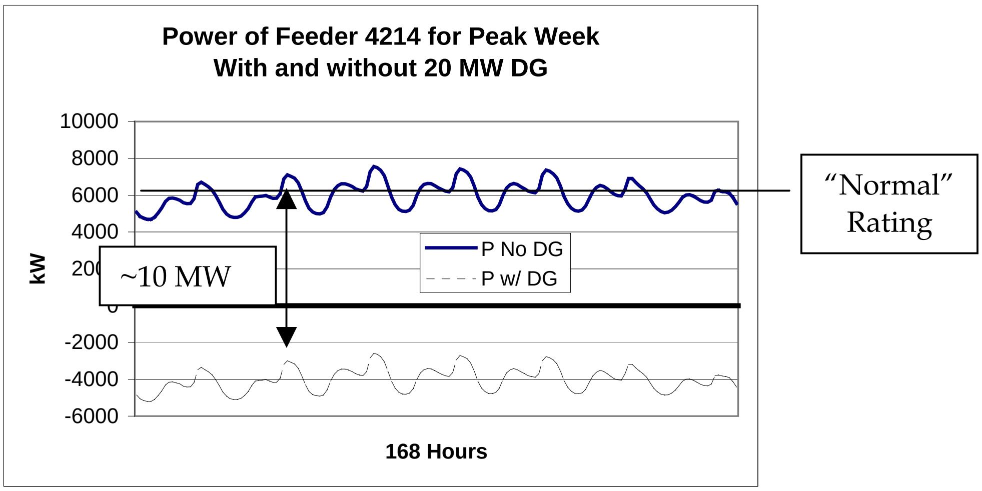


Figure 70: Feeder 4214 Power Characteristic For Peak Week, With And Without 20 MW Generation From The Proposed Plant.

Figure 71 shows the lines in the model that exceed 50% loading at the present peak load condition. There are several lines out of the Jenney substation loaded higher and at least one out of Cartwright. To achieve a greater impact on reliability from the proposed Bay Farm Island RDG facility, the load on the main part of Alameda could be redistributed so that some of it is served from the two feeders that currently serve as express feeders for Bay Farm Island. This would free up capacity on other feeders for feeder restoration considerations.

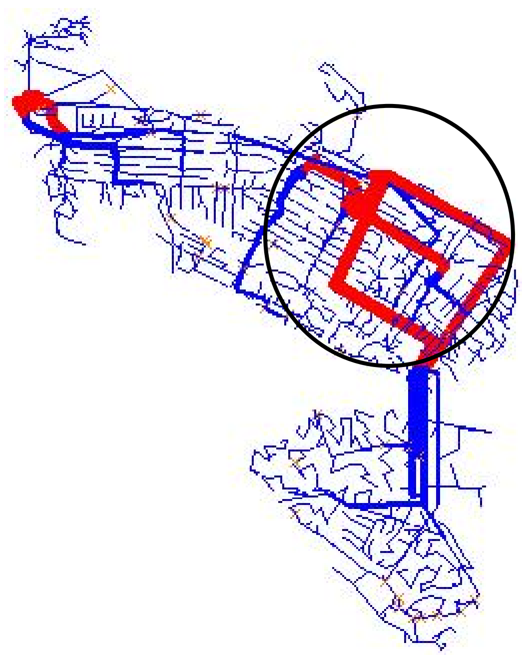


Figure 71: Highlighted Lines Exceed The Assumed Normal Rating At Present Peak Load.

Whether this restoration capacity is actually needed at present is an open question. The system likely has enough excess capacity at present to easily perform temporary switching of loads to backup feeders when it is necessary to repair cables, etc. This is more difficult in areas more distant from the substation. Engineers will have to evaluate failure history to determine the need.

Figure 72 shows the 3-D plot of the annual EEN savings for this case. The 20 MW of generation contributes only about 800 kW of incremental capacity at peak with respect to reliability issues as we have been measuring them.

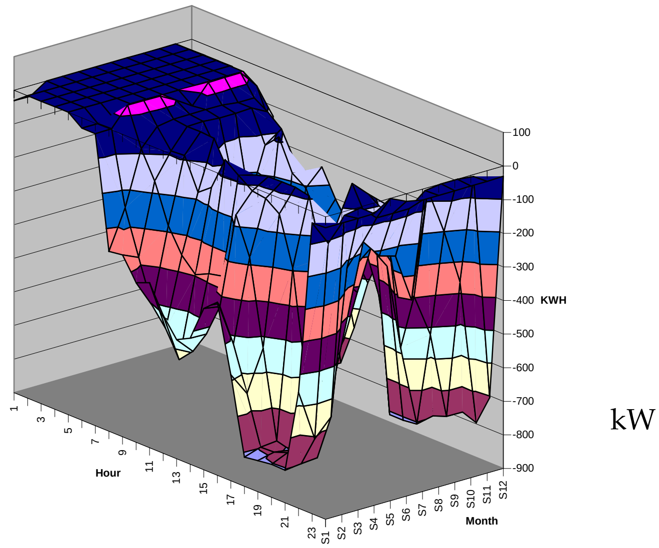


Figure 72: Depiction Of The Impact Of The Proposed 20 MW Generation, Option 1, On The Peak Hourly EEN As Compared To The Base Case. (Option 2 Is Virtually Identical.)

The proposed generation should make it easier to serve the system in case of a transformer failure in either of the two main substations, although there is sufficient nameplate capacity to accomplish this at present without generation. Voltage regulation a peak load should be easier to accomplish if generation were available in this case.

Figure 73 depicts the peak power flows in the system as represented in the model. Each substation has 110 MVA of maximum transformer nameplate capacity and could conceivably serve the entire system load in the event of loss of both transformers at one substation. However, voltage regulation to the extreme points would be difficult at peak load times. 20 MW of RDG would certainly help in this case by freeing capacity to be used elsewhere. More sophisticated controls may be needed to help regulate the voltage. The question is: Is the capability to cover a double contingency of value? Only a few utilities design for double contingency failures on a regular basis.

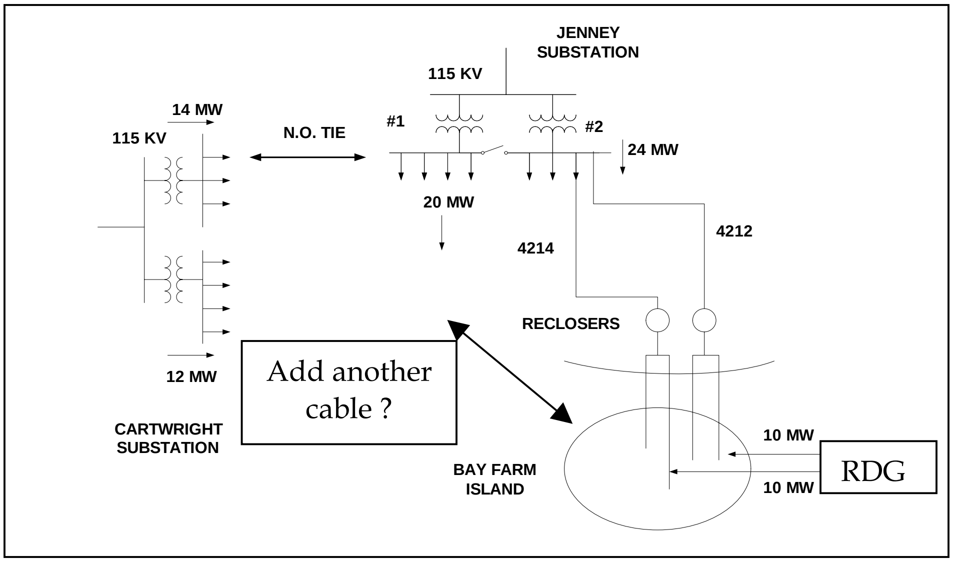


Figure 73: Schematic Of Alameda P&T System With Proposed Plant Showing Substation Power Flows Before Adding The Generation.

If another cable were added as shown in the figure, connecting Bay Farm Island to the main part of Alameda, the proposed plant could further assist in the reliability of the Alameda P&T system. This would allow more of the load to be supplied from the RDG and, theoretically, provide better coverage for such serious contingencies. The qualifier "theoretically" is used because some engineering analysis would have to be done to determine if this is actually feasible. No other circuit configurations have been studied in this analysis.

If the plant were to be sited near PG&E transmission lines, another option would be to interconnected the generation with the transmission system and the deliver the power to Alameda P&T through the two main substations. This would be the same as the existing situation and yield no benefits to distribution reliability.

Figure 74 shows the EEN curves for all cases for easy comparison. The top curve is the Base Case. The bottom curve is the Reference Case 1 (consisting of 16 500 kW generators dispatched as baseload). This clearly shows the dependence of reliability benefits on generator location. If one were able to site and size generation optimally, substantial benefits can be achieved. One may, or may not, be able to achieve benefits for generator sited for some other purpose.

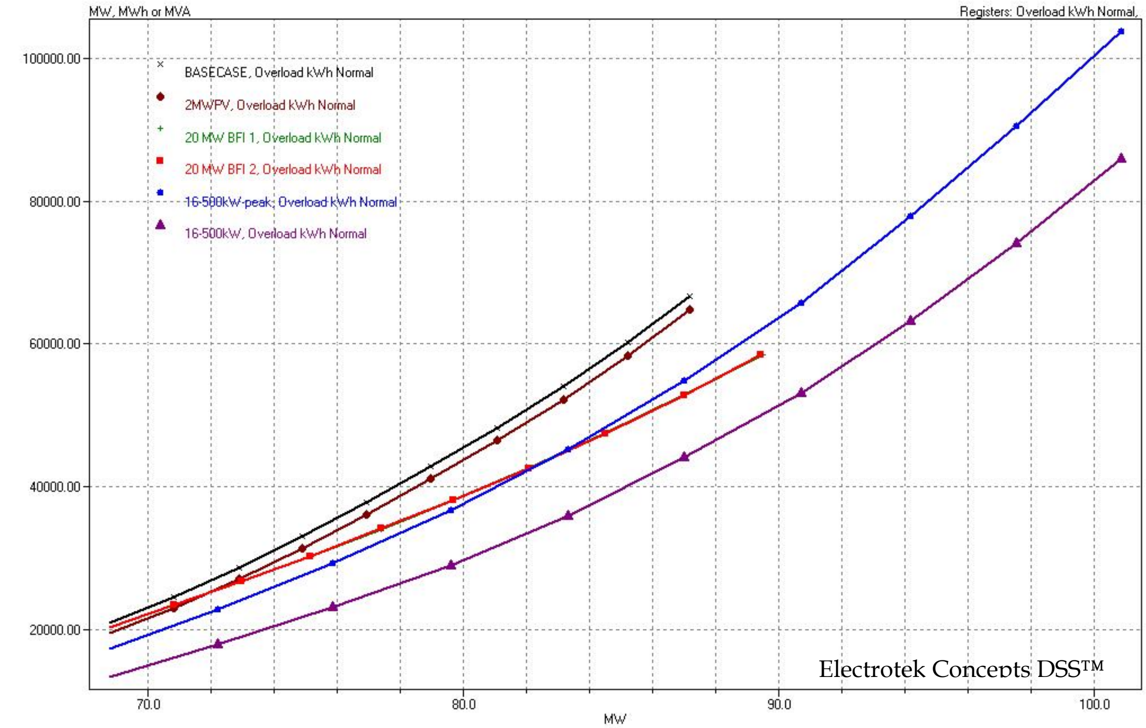


Figure 74: Comparison Of EEN Computed For All Cases.

5.5. Loss Evaluation

The losses were computed for the same simulations that were performed for the EEN calculations. The results provide some interesting insights and serve to reinforce the conclusions with respect to reliability.

Normally, we are interested only in the actual loss savings (vertical distance between the curves in the following figures). However, it is also useful to determine the incremental capacity (horizontal distance) to judge the effectiveness of a proposed RDG plan. Losses are an indication of how well the source of power is positioned with respect to the load. Incremental capacity values are often similar to those for EEN calculations for well-positioned RDG devices. Although losses generally decrease when RDG is added to a distribution system, the losses will sometime increase, indicating that the generation is too large for the lines in the area.

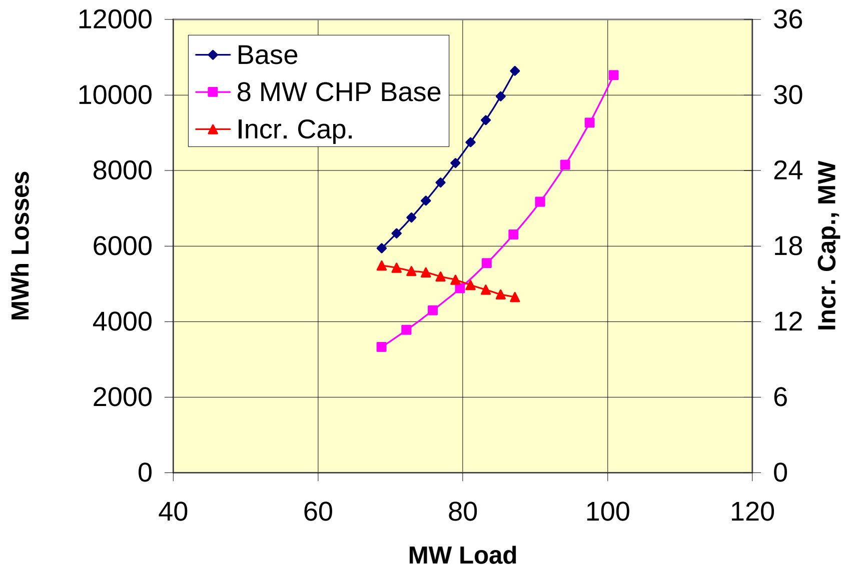


Figure 75: Annual Losses For 8 MW Of Baseload Generation Sited In 16 Units Of 500 Kw For Maximum Benefit To Distribution System Losses (Reference Case 1).

As would be expected for a case in which the generation was specifically sited to reduce losses in the distribution system, Reference Case 1 (Figure 75) performs very well with respect to losses. Initially, the system can serve approximately 17 MW more load before the losses would rise to the value of the base case without generation. This is more than the incremental capacity predicted by the EEN calculations.

This is not surprising because the generation is sited in the areas that contribute most to losses and is assumed to operate continuously. Therefore, there is a contribution to loss reduction year-round. In contrast, the contribution to EEN reduction occurs only when the load would normally exceed 50% capacity. As pointed out previously, the EEN benefit can be achieved by any generation that can be called upon at any time to serve the need. It does not have to be running continuously. However, it must be running continuously to achieve the loss benefit shown here.

The incremental capacity gain declines as the load grows as this scheme is less able to compensate for losses elsewhere in the system.

The annual loss savings (vertical separation of the curves) are on the order of 3,000 MWH. If the generation is not able to run year-round as this simulation assumes, the loss savings will be less.

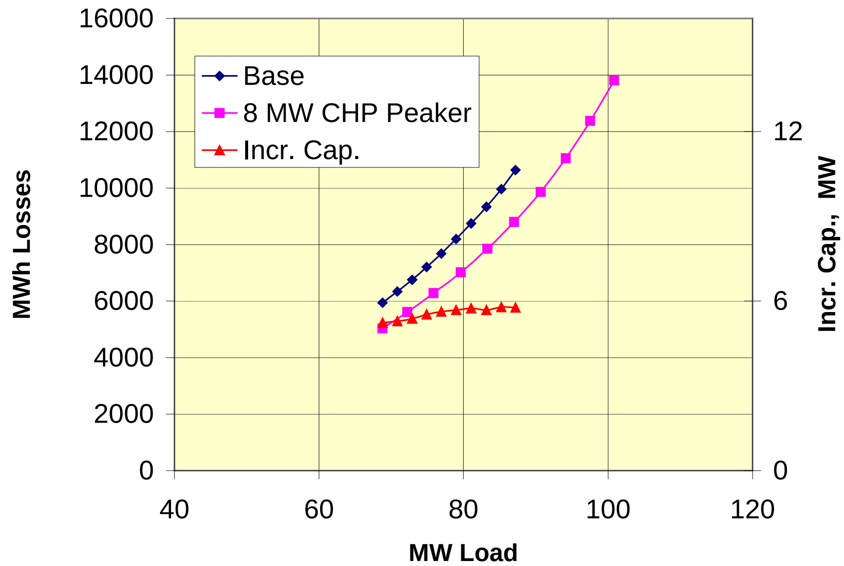


Figure 76: Annual Losses For 8 MW Of Late Afternoon Peaking Generation Sited In 16 Units Of 500 Kw For Maximum Benefit To Distribution System Losses (Reference Case 1).

The losses for the case where the 8 MW of generation is operated as a late afternoon peaker are shown in Figure 76. The system can serve almost 6 MW of additional load before the losses return to present values. This is obviously not quite as effective as the case where the generators are able to run at all times. However, the result is not bad and round-the-clock operation of RDG to reduce losses may very well be uneconomical. Typical annual savings for this case are on the order of 1,000 MWh.

The apparent incremental capacity continues to increase as the loading increases. This is confirmation that the peaking generation addresses the most constrained area and time. It is also a trend we see on relatively lightly loaded systems. Eventually, this curve should peak and reverse as other parts of the system become heavily loaded. It appears to be leveling off, which is often an indication that this dispatching method has accomplished almost all it can do by itself. Compare this with the declining incremental capacity characteristic in the previous chart for the continuous running generation. The decline suggests that losses in other parts of the system at off-peak hours are not being addressed by the generation. That might be an argument for not considering 24-hr CHP applications in these locations. If applications are to be encouraged, they should be ones that more closely match the system load shape.

The incremental capacity curve for the 2 MW of PV generation also has a downward trend (Figure 77). As the load grows, the apparent effectiveness declines. In this case, it is due primarily to the fact that the PV generation offers no relief for the evening load peak. As the load grows, the savings achieved by the PV generation is exceeded by the growth in losses due to the growth in the evening peak.

Using losses as the metric, 2 MW of solar PV uniformly distributed around the system allows for serving about 0.6 MW more load. As the load grows toward 90 MW, the value reduces to about 0.4 MW because the load peaks occur at a time when the PV is unable to counter the losses. These values are similar to, but somewhat less than the incremental capacity values estimated from the EEN calculations.

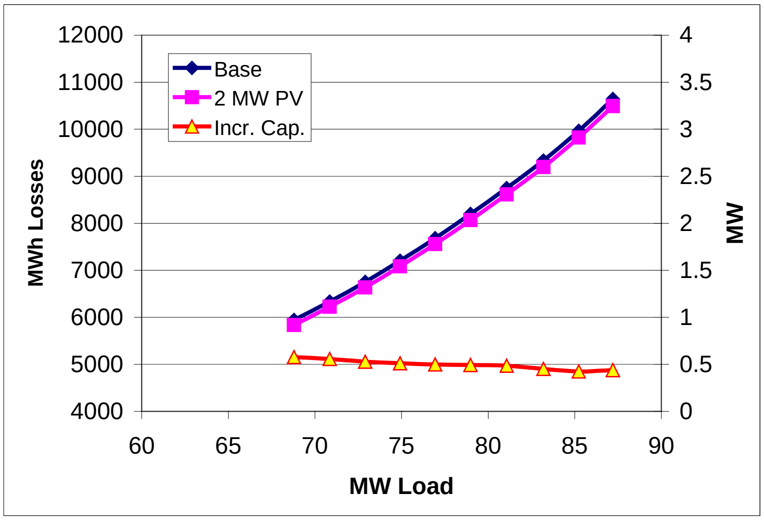


Figure 77: Annual Losses For 2 MW Of Solar PV Generation Uniformly Distributed Throughout System (Reference Case 2).

The effective incremental capacity estimated from annual loss savings for the two options for connecting the proposed 20 MW RDG connected into Bay Farm Island is substantially higher than that predicted from EEN calculations. Option 1 (Figure 78) shows better performance than Option 2 (Figure 79), although there is likely not enough difference for this to be a deciding factor. The losses shown in these charts include only the lines in the existing Alameda P&T system. One should also take into account the losses in the lines to deliver the power from the proposed plant to the Bay Farm Island interconnection point. In that case, the 35 kV option (option 2) has a distinct advantage with respect to losses, as pointed out in the Engineering Screening Analysis Chapter.

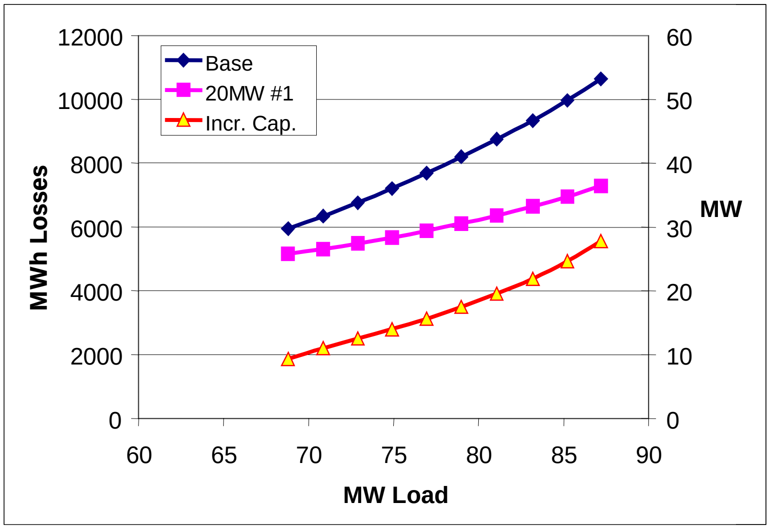


Figure 78: Annual Losses For 20 MW Plant Option 1 (12 Kv Cables).

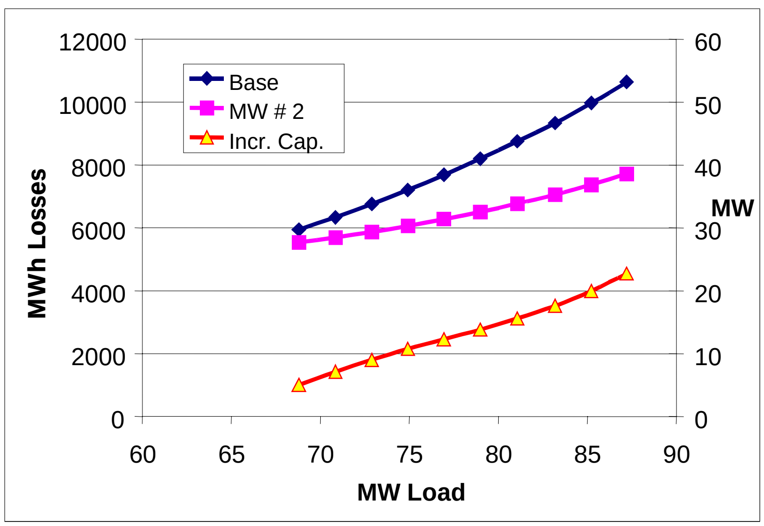


Figure 79. Annual Losses For 20 MW Plant Option 2 (35 Kv Cables).

The analysis shows that the load can grow by roughly 10 – 20 MW, depending on total load, before the total system losses are the same as the base case with no generation. As with the EEN calculations, the greater benefit to the operation of the Alameda P&T system will occur in the future when the system load grows. However, the loss value is increasing faster. The losses addressed by this generation are largely those in Feeders 4212 and 4214. At present load levels, 20 MW of generation results in substantial excess power being shipped back up these feeders to the Jenney Substation (see Figure 70). This results in losses. As the load on Bay Farm Island increases, the losses in these feeders would actually decrease with the proposed generation on line. More power would stay on the Island and the average current in the feeders would decrease. At some load level, the current would start to increase again. This would be well into the future, far beyond the time frame represented in this simulation, barring the addition of some new large loads.

Both options show a greater impact with respect to losses than with respect to EEN. The reason for this has its roots in the definition of "system" as described earlier in this report. This analysis is done with the entire Alameda P&T system. The feeders to Bay Farm Island are longer than the average feeder in the system. Because they are essentially express feeders, the current is heavy for the entire run to the reclosers before the channel crossing. Thus, the feeders have a disproportionate impact on the total system losses while the impact on capacity is assumed to be about the same as other feeders. Therefore, the loss functions are more sensitive to the loading and the amount of generation than the EEN functions.

Figure 80 shows the annual shape of the difference in losses between the base case and the proposed RDG plant (option 1). The shape for option 2 is similar, but offset slightly. It is interesting that the plant does result in net savings (negative number in this view) most hours of the year. The losses are actually increased in the early morning hours when the load is lightest. Obviously, this could be controlled with intelligent dispatch of the generation. Keep in mind that these losses are relatively small compared to the potential losses in the cable connecting the generation to the 12 kV feeders on Bay Farm Island.

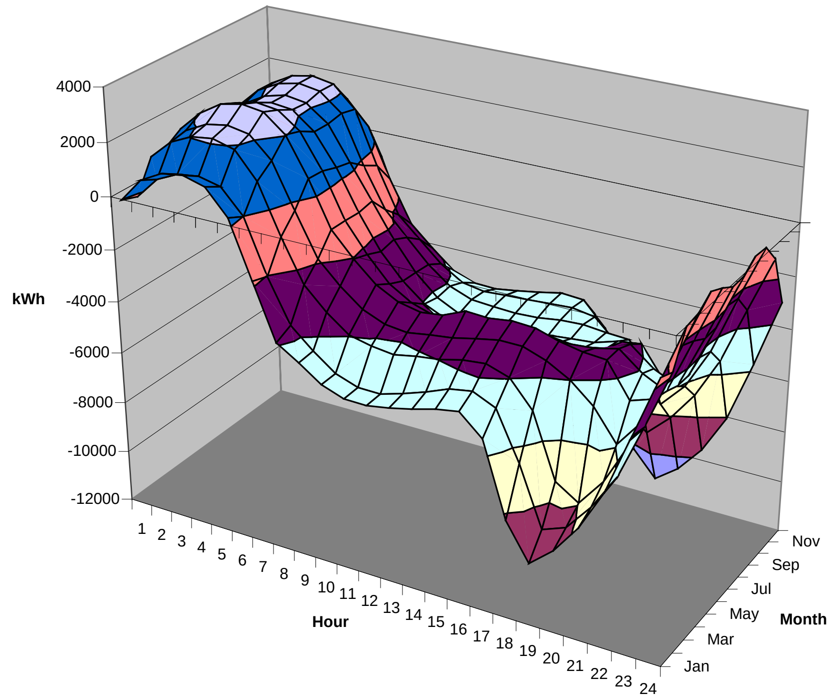


Figure 80: Depiction of increment losses, kWh, in the existing Alameda P&T primary system due to baseload operation of the proposed 20 MW plant (option 1) serving Bay Farm Island.

5.5.1. Comparison of Losses for All RDG Cases

Figure 81 shows the annual losses in the existing Alameda P&T system for all the cases considered here. All the cases show some improvement in power delivery losses. Reference Case 1, in which the generation was intentionally sited for maximum impact on losses, clearly performs better than the other cases by a wide margin. It allows for an increase in capacity over the Base Case that is more than twice the size of the generation. This is quite good and illustrates what might be achieved if there were complete freedom to choose generator characteristics and locations. This distribution of generation is also quite effective in releasing feeder capacity.

The 2 MW solar PV case has marginal improvement over the base case. Solar generation fades too early to help with the evening peak and is not available for losses throughout the night. The other options were assumed to be dispatchable and available either 8760 hrs per year or 7 hours per day, in the case of the peaker.

For the two cases for the proposed RDG, the circuit losses for the 35 kV case (Option 2) compute higher than the 12 kV case. This is due to a different current distribution on Bay Farm Island and Feeders 4212 and 4214 that apparently arises from the different technique for interconnecting the options. However, keep in mind that the delivery losses from the hypothetical plant location to Bay Farm Island for the 35 kV case are substantially lower, yielding a net loss savings over Option 1. The losses shown are for the same part of the system as represented in the Base Case for comparison purposes.

The loss curves for the two options increase at a rate less than Reference Case 1 as the load grows. This analysis suggests that the generation is reasonably well-positioned to handle future load growth. Again, this analysis suggests that the greater benefit from the generation will come later on.

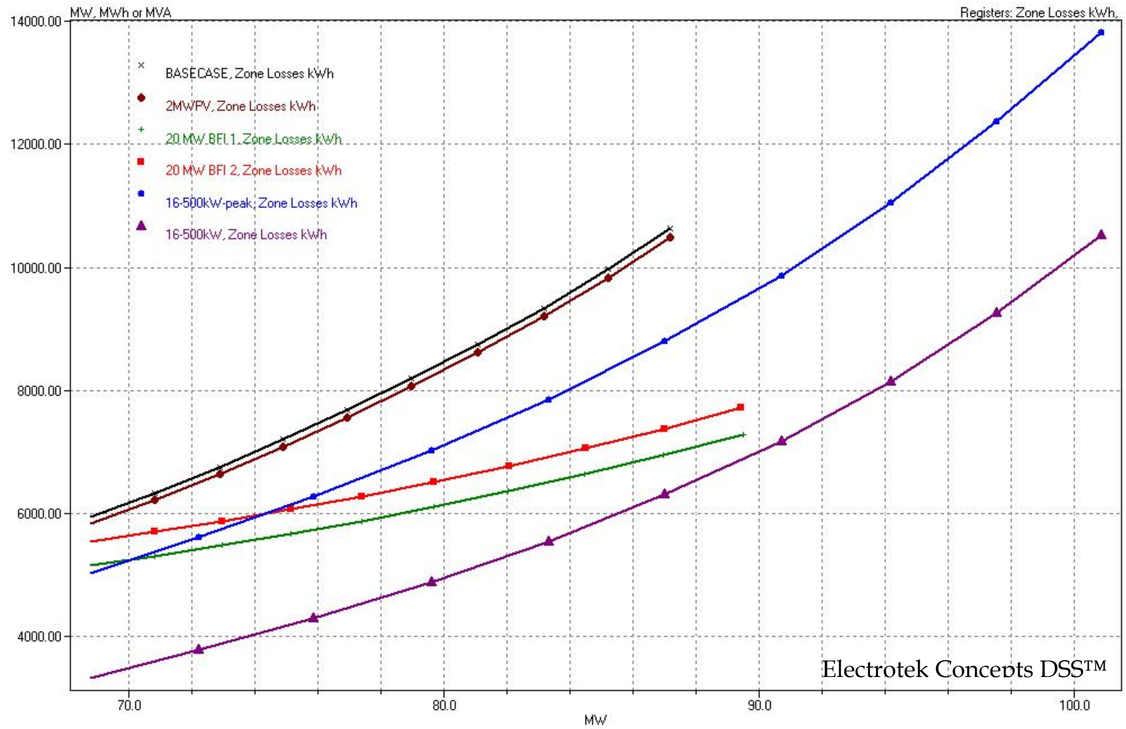


Figure 81: Comparison Of Annual Losses In The Existing Alameda P&T System For The Various RDG Options.

5.6. Valuing EEN and Losses

This report provides only the fundamental data for the economic analysis, which will be prepared subsequently. For informational purposes, some basic methodologies for converting the results of this analysis to cost values are now presented briefly.

The conversion of annual loss values to cost is straightforward: Multiply by the average cost of energy. For example, the annual losses in the primary distribution system appear to be approximately 6,000 MWh. If the average cost of energy is \$30/MWh, the annual cost is 6000 x 30 = \$180,000.

Converting the EEN to cost is less tangible. EEN is a measure of the energy at risk of being unserved in case of a failure within the Alameda P&T system. It is implicitly assumed that if a failure were to occur, all the loads except for the amount exceeding the

Normal limit can be promptly picked back up by simple switching. EEN must first be converted to Expected Unserved Energy (EUE) by some method. A simple way to do this is to multiply by the probability of a distribution-related outage. For example, if the annual customer outage time is 1.5 h then the EUE might be estimated by multiplying the EEN by 1.5/8760. At present loading, the annual EEN is computed to be approximately 20,000 MWh. Thus, the EUE might be estimated to be 20,000 x 1.5/8760 = 3.425 MWh/yr.

The EUE value is converted to cost by multiplying by the value of unserved energy. For single contingency evaluation on distribution systems, this is generally between $4 and $10/kWh for industrial and commercial loads. Thus, the reliability cost would range between approximately $14,000 and $34,000 per year.

Compared to other costs in this problem, this is not a large cost. The savings yielded by either of the two options is but a small fraction of this cost at the present loading. This suggests that reliability costs will not be an influential factor in the overall economics of the proposed RDG plant to serve Bay Farm Island.

5.7. Economic Evaluation of Reliability Impacts

Within the reliability analysis, we investigate the economic value of renewable distributed generation (RDG) impacts on the electric reliability of the Alameda P&T 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 Alameda P&T 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 in 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 that there is 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 (goal 3), power quality (goal 2) and to a lesser degree, the extent and duration of outages (goal 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 (in the case of Alameda P&T the normal limit equals 50% of current capacity). 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.

5.8. 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 performed in Task 3.1 of this report, 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 Task 3.1) due to the installation of the RDG; *p*(outage) is the probability of having an outage, absent the RDG; and 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:

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

where: Subscript c corresponds to the specific contingency scenario, and DUE is the change in unserved energy for that contingency scenario.

Contingency scenarios were not simulated for Alameda P&T.

Unlike other cost elements considered in this study, there is no market for VRI[4]. The value to customers is a “soft” 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

4 Technically, programs such as interruptible or curtailable rates or demand bidding programs are a form of market for lower reliability services, but their use is not widespread and does not typically apply to residential or small commercial customers.

opportunity cost of electric power, which equals the value of unsupplied electricity.[5] 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 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 82 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.

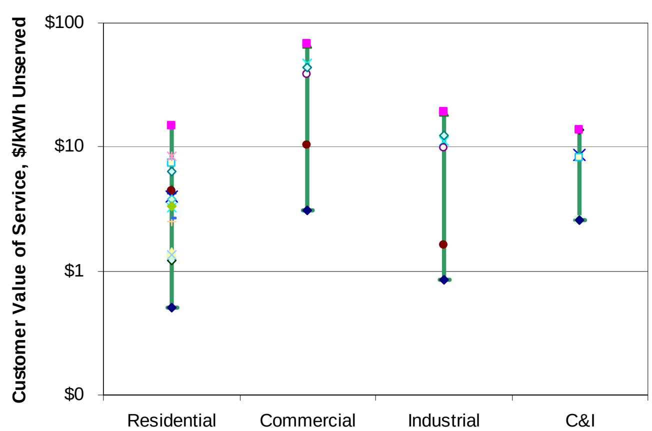


Figure 82: Typical Range Of Reported Values For Customer Value Of Service (VOS).

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

5 Woo, Chi-Keung, R. Pupp, *Cost of Service Disruptions to Electricity Customers*, *Energy*, Vol 17 No 2. 1992 Pergamon Press.

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.

Typical mid-range VOS values are listed in Table 20.

Table 20: 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 Alameda P&T are shown in Table 21 below. The table shows the impact of an equipment failure that occurs randomly within the year and lasts for 24 hours. The △EEN column shows the reduction in annual EEN as a result of the RDG installation. Given the EEN under the "no DG" case, this 1 day out of 365 translates to about 2.2 outage hours per year[6]. The probability of an outage (*p*(outage)) and the VOS value of

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6 EEN = 20,933,228 , Total kWh Consumption in the year = 388,249,793, so the percentage of annual consumption that would go unserved from a failure that lasts the entire year is 20,933,228 / 388,249,793 = 5.4%. Combining this value with the likelihood of an equipment failure gives the likely percentage of energy unserved (assuming the probabilities are independent) = 5.4% * 1/365

$8/kWh are representative of a mixed use area with residential, commercial, and light industrial customers in California.

Table 21: Value of Reliability Improvement (Year 2004)

Case	EEN (kWh/yr)	△EEN (kWh/yr)	*p* (outage)	VOS ($/kWh)	VRI ($/yr)
No DG	20,933,228	N/A	0.27%	$8	N/A
2 MW PV	19,459,230	1,473,999	0.27%	$8	$ 31,838
8 MW CHP Peaker	17,240,002	3,693,226	0.27%	$8	$ 79,774
8 MW CHP Base	13,382,090	7,551,138	0.27%	$8	$ 163,105
20 MW Baseload 1	20,213,828	719,400	0.27%	$8	$ 15,539
20 MW Baseload 2	20,205,919	727,309	0.27%	$8	$ 15,710
20 MW Baseload 1*	20,211,098	722,130	0.27%	$8	$ 15,598
20 MW Baseload 2*	20,215,287	717,941	0.27%	$8	$ 15,508

Total usage is 388,249,793 per year, so the annual EEN in the "no DG" case represents only 5.4% of the total annual usage. This represents a small risk of outages related to loading levels. The risk becomes even smaller when one considers the probability of an equipment failure that could drop the area load carrying capability to the "Normal" limit. Of particular note is the low VRI offered by the 20MW Baseload scenarios. This low value is a result due to a location for the 20MW plant that is less beneficial when compared to the placement of the 8MW CHP units. The fivefold difference in value highlights the importance of conducting the engineering and reliability analysis as part of a comprehensive RDG analysis.

5.8.1. Deferral Benefit of DG

Using this approach, we are able to determine how many years the T&D additions 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 T&D 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 that are attained from delaying the construction of a T&D expansion project. 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 83 shows how deferral length could have been derived from the Alameda P&T EEN curves. Assuming that a project were required in year 1, with peak load at 68MW, the installation of 8MW of CHP DG could have deferred the project by about 5 years

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= 0.015%. Assuming a 60% system load factor, this translates to about 2.2 hours per year of outage on average for Alameda P&T customers (0.015% * 8760 / 60%).

without lowering reliability to customers. The dotted line drawn horizontally from the Base EEN curve intersects that 8MW CHP Base EEN curve at a point that is 7MW higher than the Base case. This indicates that with the installation of the DG, peak load in the area could grow by 7MW before EEN returned to year 1 levels. The 7MW cushion would allow Alameda P&T to delay the T&D project by five years.

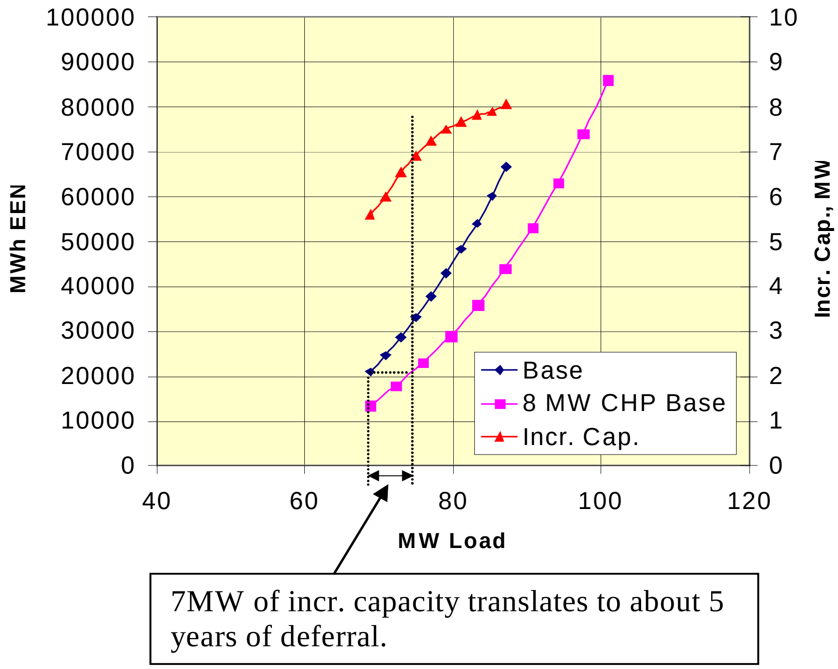

Figure 83: EEN-based T&D Deferral

5.8.2. Deferral Benefit Feedback Loop

Depending upon the electrical configuration of the T&D system and the assumed location of DG, the number of deferral years that can be attained from DG could differ from the number of years assumed in the initial avoided cost calculations.

The avoided cost calculations base the years of deferral on annual load growth for the area. In the case of Alameda P&T, the annual growth for the study area is about 1.4 MW per year for the next ten years[7], so an 8MW generation source would be expected to defer the need for T&D upgrades by about six years. The engineering calculations from Task 3.1, however, show that that the deferral length based on EEN would be lower --- about five years. This means that the value of the 8MW of DG capacity would be less than originally would have been estimated using the avoided cost formula described in previously in the avoided distribution capacity costs section.

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7 February 7, 2003 forecast from Alameda P&T.

A more striking example is a 20MW plant. Based on the size of the plant, the avoided cost formula would attribute high cost savings to the plant. However, the engineering analysis in 3.1.3.2a demonstrates that the location of a 20MW plant results in almost no EEN reductions in the near term. As a result, if T&D growth-related projects had been planned in the near term, a 20MW plant would have yielded virtually no deferral benefits.

Where there is a significant difference between the years of deferral based on load growth, and the years of deferral based on the EEN levels, it is important that the EEN information be fed back to the avoided cost modules to refine the DG cost effectiveness analysis[8]. This feedback loop is represented by the dashed line in Figure 84.

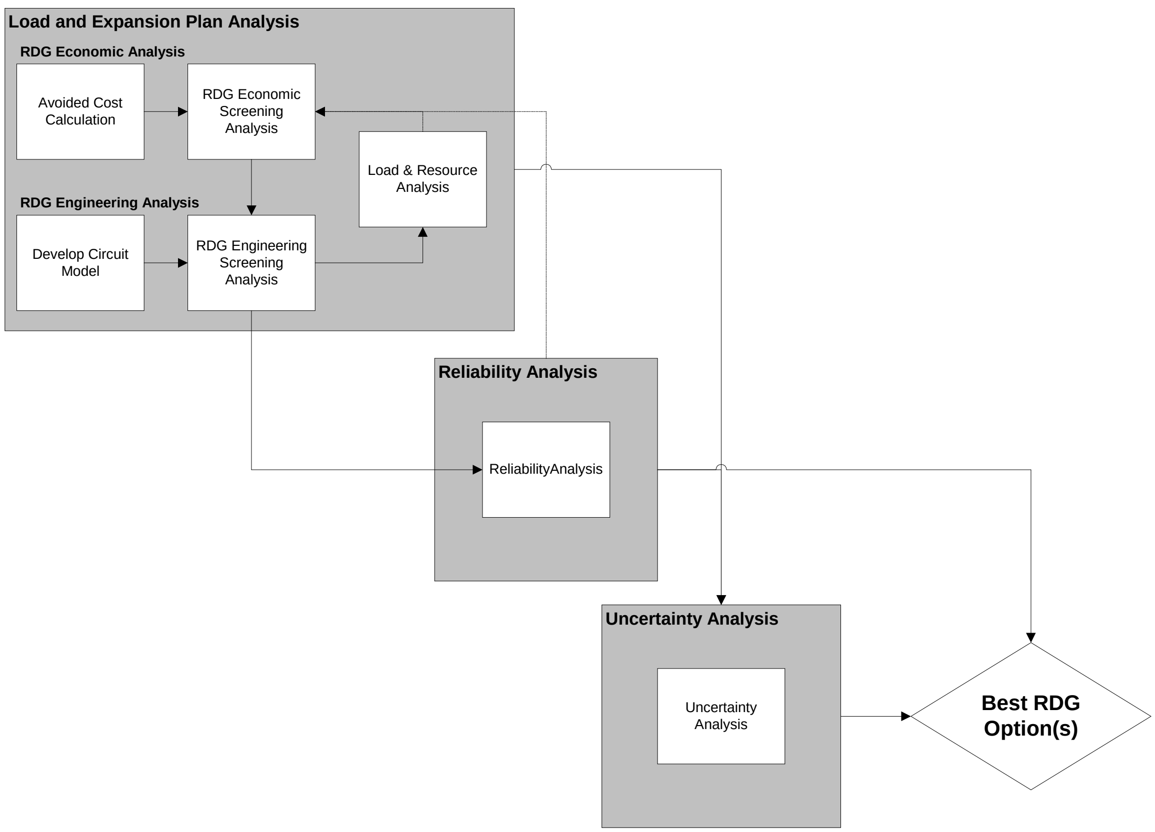

Figure 84: RDG Assessment Analysis Process Flow Diagram

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8 The feedback is accomplished by replacing the load growth figures with the amount of incremental DG capacity that would be needed to maintain reliability (EEN and EUE) at acceptable levels in each year.

5.8.3. VRI and Deferral Benefit Interaction

Unlike VRI discussed above, deferral benefit is a "hard" cost savings attributable to the installation of DG. Care must be taken, however, to properly account for changes in VRI in combination with T&D deferral. Figure 85 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 (region B). Ultimately, however, once the T&D project is completed, the customers will be better off due to a combination of the DG 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].

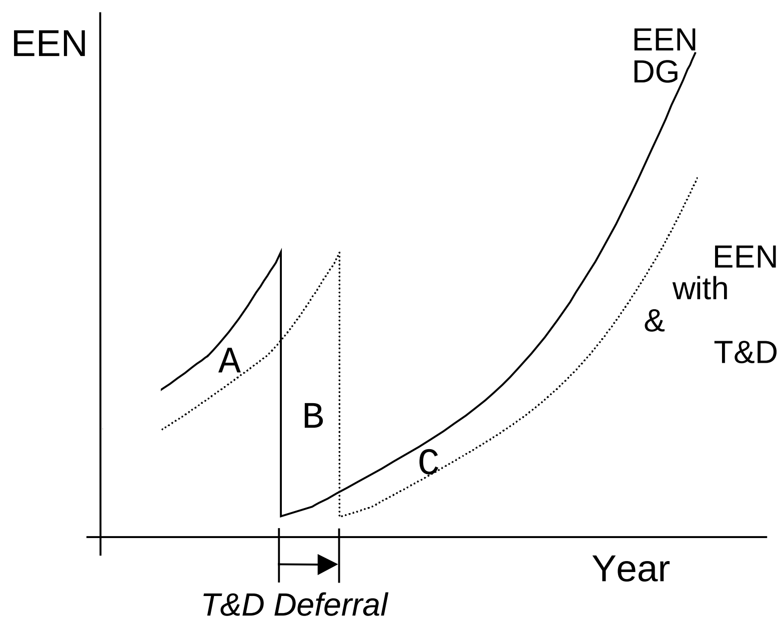

Figure 85: VRI and T&D Deferral

For Alameda P&T, there are no T&D projects in the planning horizon under consideration, so the net VRI calculations were not necessary.

5.8.4. Additional Uses of Reliability Valuations

This section discusses additional applications of the economic valuation of reliability. While there are not the author's primary recommendations, they are being provided for completeness.

5.8.5. 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. The Relative Customer VRI method develops 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 ΔEUE 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, and 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 a 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?"

5.8.6. 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 number 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 demands 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

Up to this point, we have focused the RDG Assessment project on base case variable inputs. The resulting conclusions are subject to uncertainty given the types of variable inputs used throughout the analysis. As such, E3 developed this uncertainty analysis to test how alternate scenarios for several key inputs would affect the overall results of the assessment. In this report, we describe the method we used to test the sensitivity of the RDG Assessment results to particular ranges of uncertainty in the analysis 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 six key input assumptions:

- Generation Market Prices
- Transmission Prices
- Distribution Avoided Costs
- DG Capital Costs
- Fuel Costs
- Capacity Factor

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 the change on their results. The degree of change under each scenario can also input by the user.

6.2. 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 Energy Commission 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 Energy Commission Base, Low, and High gas forecasts in our LRMC calculations. The resulting Base, High, and Low electricity price forecasts are shown in Figure 86.

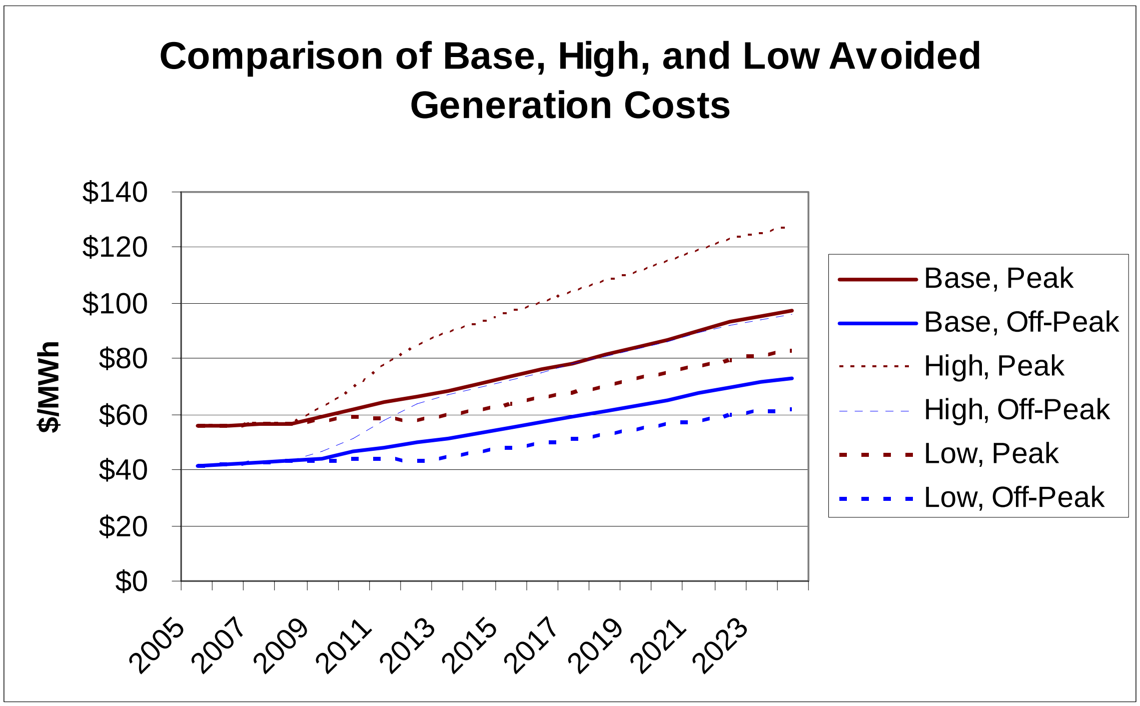

Figure 86: Comparison Of Base, High, And Low Avoided Generation Costs

6.3. Transmission Prices

In the case of uncertain transmission prices, we used a Low scenario value equal to current transmission costs of $7.02/MWh. Alameda P&T staff deems it highly likely that transmission rates will rise in the near future; we use $7.79/MWh as our Base Case value to reflect this likelihood. We input a High value at $10/MWh, reflecting considerable uncertainty surrounding the possibility of "nodal" pricing currently being developed by the California ISO, as discussed in the transmission avoided cost section.

6.4. 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. However, since there are no planned avoidable distribution investments, we do not apply alternative scenarios for distribution avoided costs.

6.5. 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.

6.6. 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; a 500 kW biodiesel unit, a 50 kW solar PV unit, and a 1.5 MW wind turbine. There are numerous RDG technologies included in the model and each of these can be tested in a similar way.

6.6.1. 500 kW Biodiesel

Figure 87 shows the sensitivity range of TRC test results obtained for a 500 kW biodiesel generator 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, analysts can vary multiple inputs at the same time using the RDG screening tool.

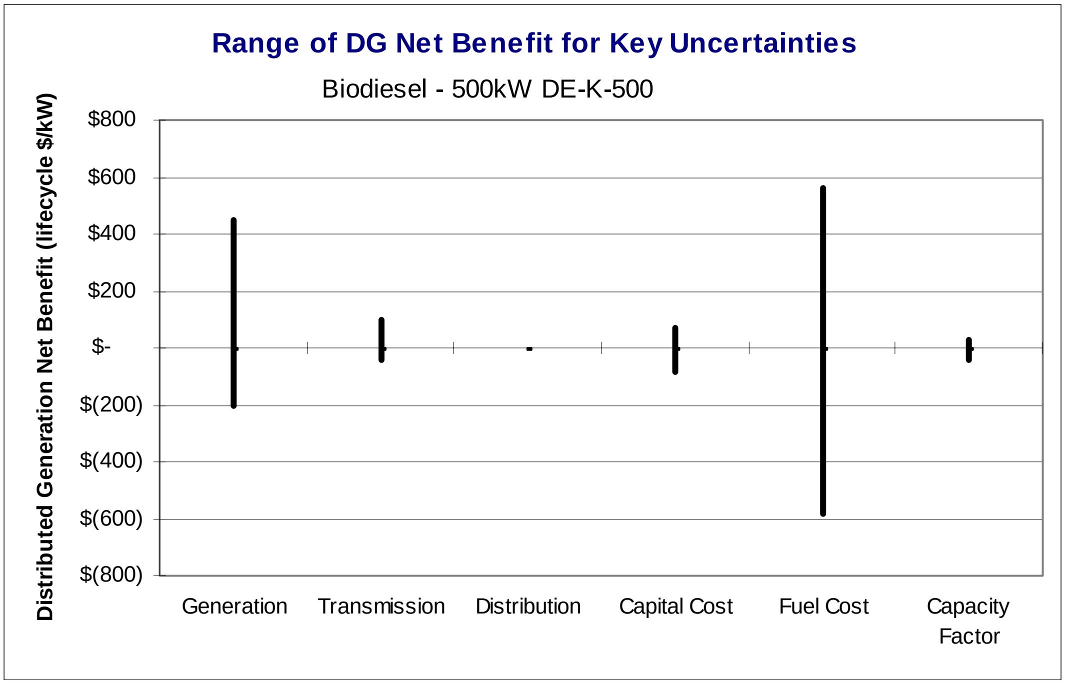

Figure 87: Net Benefit Range For Key Uncertainties, TRC Test

As can be observed in Figure 87, the 500 kW biodiesel unit we screened is very nearly cost-effective under the TRC test in the Base Case and can swing in either direction depending on whether each variable is set to the High or Low scenario.

Figure 88 shows the results of the TRC test sensitivity analysis in the form of a "spider diagram." As in Figure 87, 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 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.

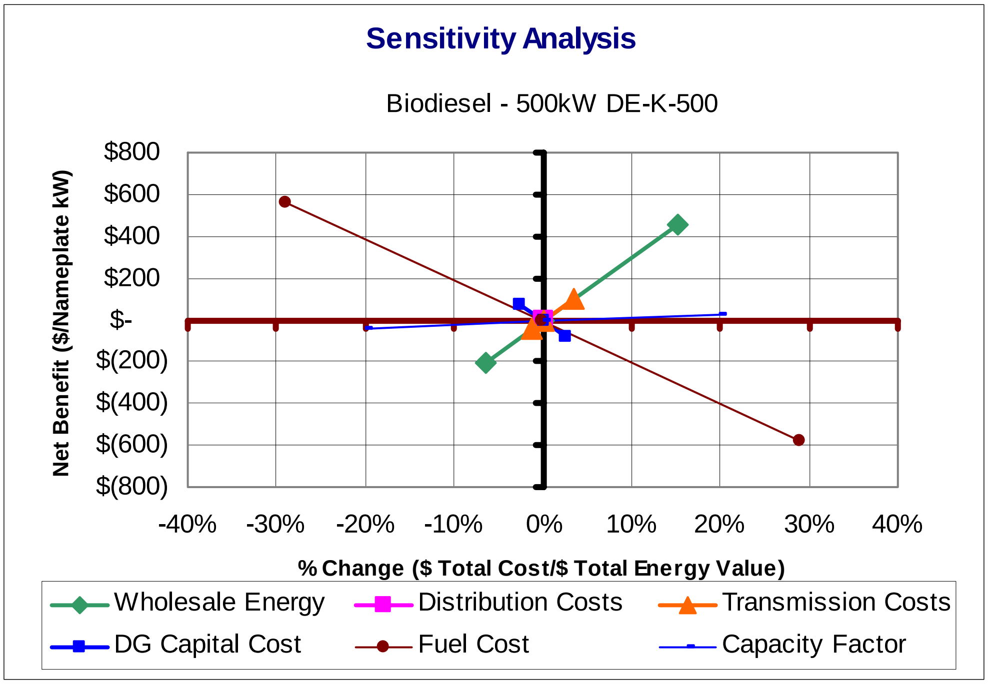

Figure 88: Sensitivity Analysis For 500 Kw Biodiesel Generator, TRC Test

The percentage change along the horizontal access is expressed as the change in the lifecycle value of the variable in question, relative to the change in lifecycle value of the generation output of the unit. For example, transmission prices vary from $7.79 in the Base Case to $10.00 in the High case. While this is an increase in the transmission price of almost 30%, the ratio is calculated as:

$$\% \text{ Change} = (T_H - T_B) \,/\, (G\ Output_B) = 4\%$$

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 500 kW biodiesel 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 only a small 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.

6.6.2. 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 89 and Figure 90. 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.

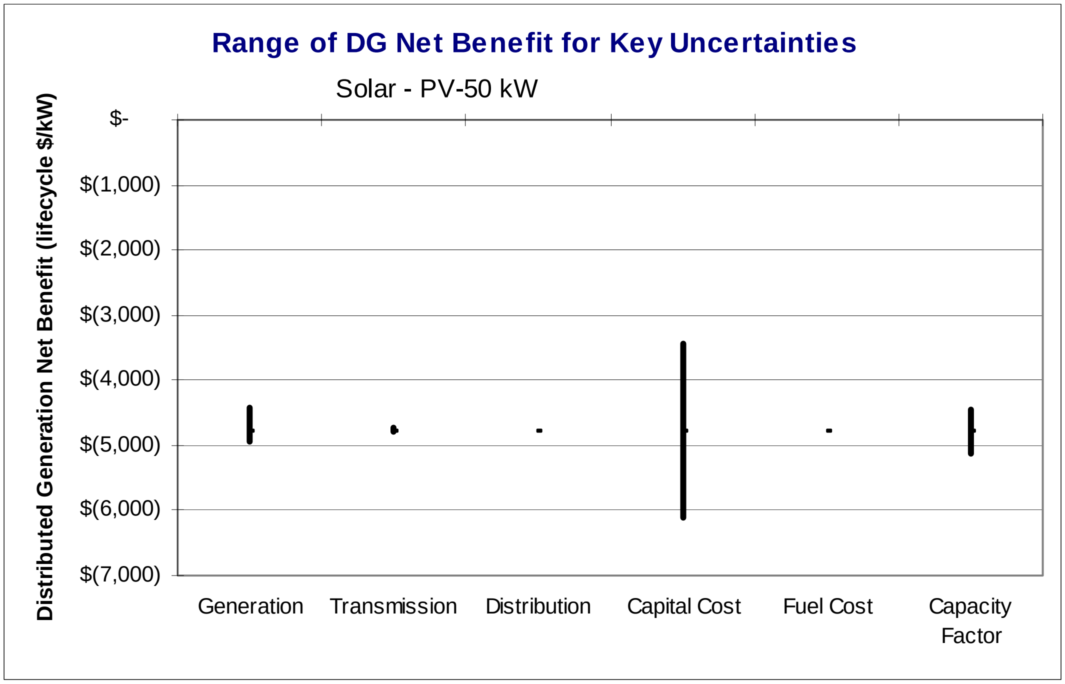

Figure 89: Range Of Net Benefits For 50 Kw Solar PV, TRC Test

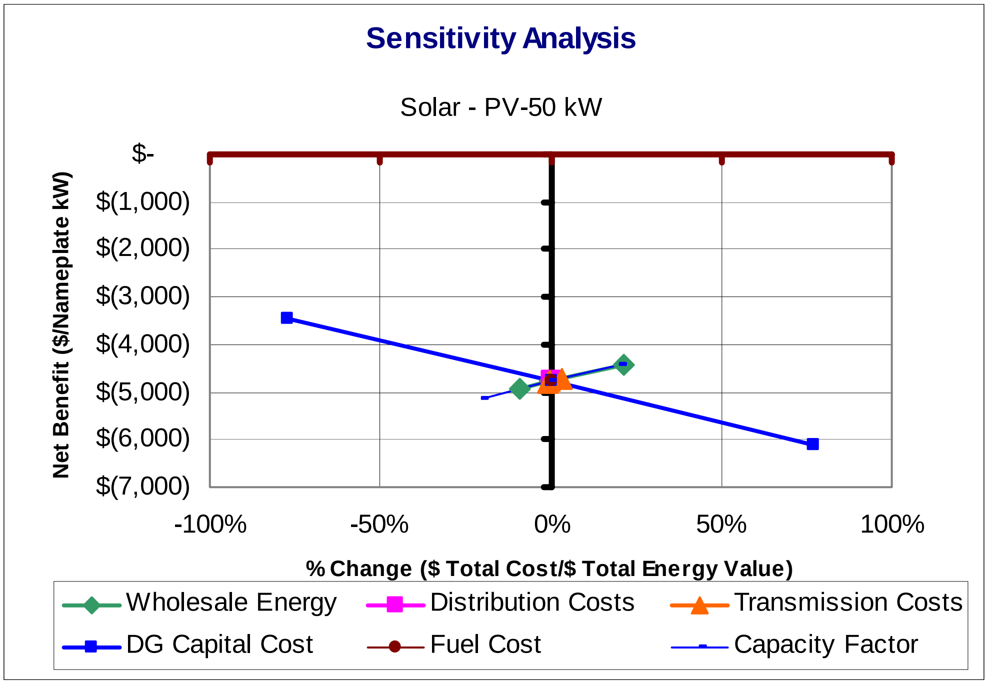

Figure 90: Sensitivity Analysis For 50 Kw Solar PV, TRC Test

6.6.3. 1.5 MW Wind Generator

Figure 91 and Figure 92 show the sensitivity results for a 1.5 MW wind generator. Because we assume that this unit is interconnected with the grid at the bulk transmission level, there are no avoided transmission costs and therefore no corresponding sensitivities. The unit, while cost effective at the base case, can become cost ineffective if capital costs are at the high end of the sensitivity range or if the capacity factor is at the low end of the sensitivity range. The capacity factor of the wind unit is particularly important in determining the cost-effectiveness of this technology.

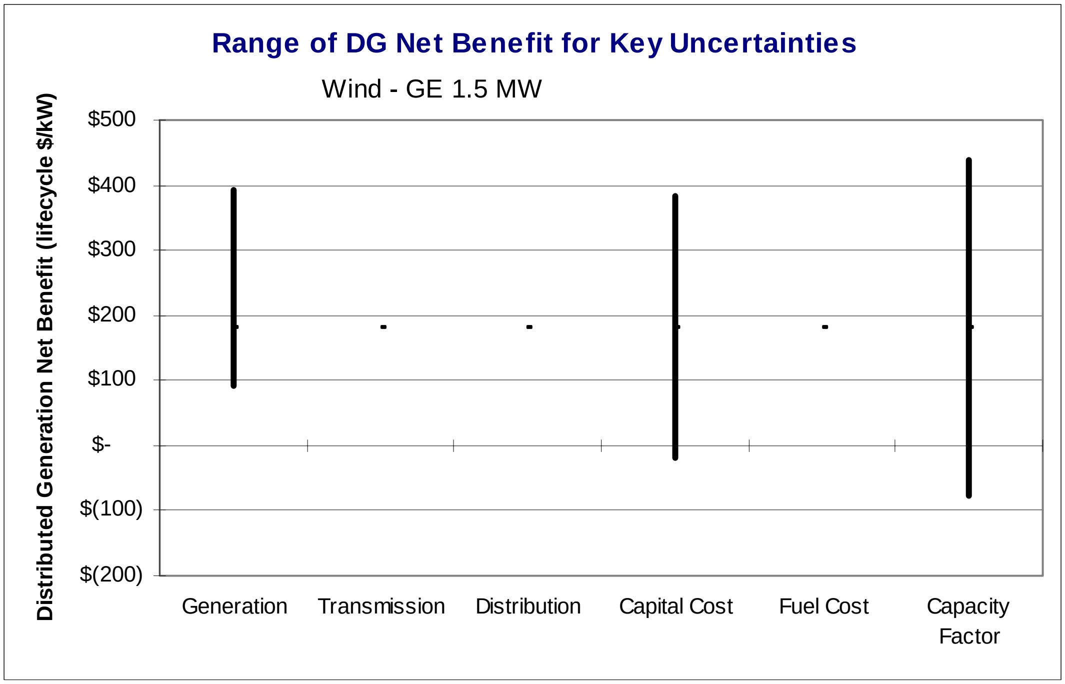

Figure 91: Range Of Net Benefits For A 1.5 MW Wind Generator, TRC Test

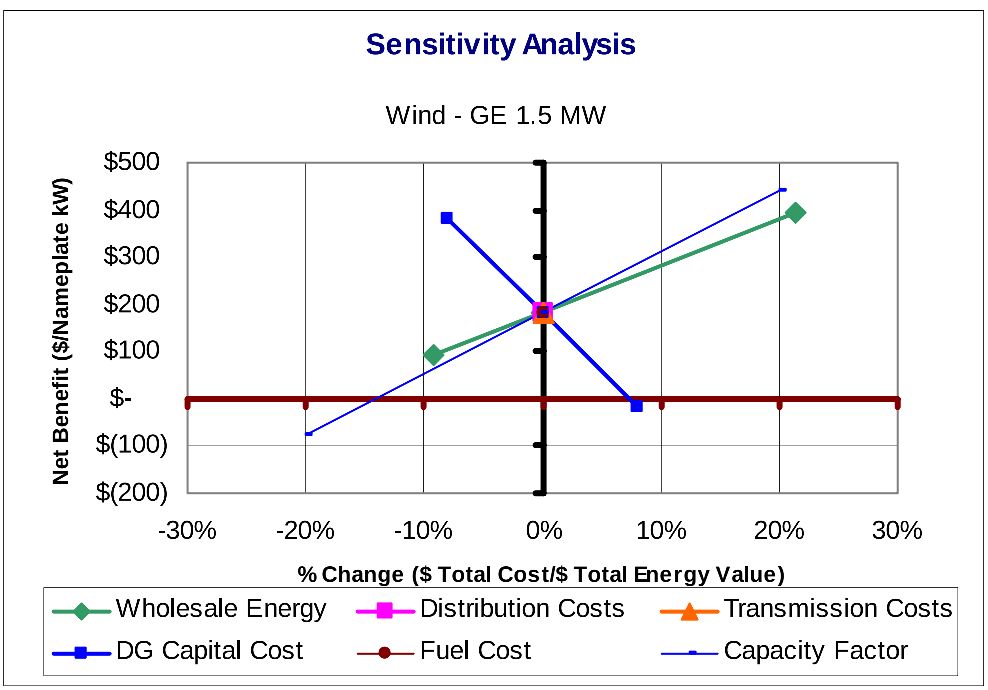

Figure 92: Sensitivity Analysis For 1.5 MW Wind Generator, TRC Test

7.0 Conclusions

The results of the Alameda P&T 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 Alameda P&T with valuable information for future decision making that includes the specific benefits RDG could provide on their distribution system.

The major findings of this assessment methodology application include:

1. Alameda P&T system should accommodate approximately 30 MW of uniformly distributed RDG without significant changes.
2. Beneficial generation must be able to produce power in the early evening hours in winter months because Alameda P&T is a winter peaking utility. This casts doubt on the benefits of solar PV technologies to the power delivery system unless coupled with significant storage.
3. Applications of RDG on Bay Farm Island would appear to offer the greatest potential benefit due to the distance of that load from the substation.
4. Most of the areas on the main island of Alameda offer potential benefits for RDG siting due to the distance from the substation and some of the bayside commercial areas on the opposite side of the island from the Jenney substation have potential benefits similar to Bay Farm Island locations.
5. The most cost-effective RDG technologies for Alameda P&T from a total resource perspective are biogas generators operating as combined heat and power resources.
6. Large-scale wind is also a cost-effective renewable resource but a sufficient wind resource is not available within Alameda to support this technology as a local distributed energy resource.
7. Reliability benefits are relatively small because Alameda P&T has sufficient system capacity available at present.

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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-1

Appendix A-1
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 RDG 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. 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].

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

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.

1.2. 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 the 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 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 ugly, 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.

1.3. 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.

1.4. 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.

1.5. 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.

1.6. 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.

1.7. 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. 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 that 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.

1.8. 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.

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.

1.9. 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 its 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.

1.10. Performance characteristics

Table 1 presents 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 address intermittency while maintaining a low emissions footprint.

Table 1: Performance Characteristics of RDG Technologies

	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