Renewable Distributed Generation Assessment: City of Palo Alto Utilities Case Study

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Energy and Environmental Economics, Inc
Electrotek Concepts, Inc.

JANUARY 2005
CEC 500-2005-029
Prepared By:
Snuller Price, Carmen Baskette, Mike King, Brian Horii, and Peter Light
Energy and Environmental Economics, Inc.
San Francisco, California

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

Contract No. 500-01-042

Prepared For:
California Energy Commission
Public Interest Energy Research (PIER) Program

Valentino Tiangco, Prab Sethi,
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

DISCLAIMER
This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.
ACKNOWLEDGEMENTS

We would like to acknowledge the California Energy Commission, San Francisco Public Utilities Commission / Hetch Hetchy Water and Power, City of Palo Alto Utilities, and Center for Resource Solutions for their valuable role in this research. In particular, we would like to acknowledge the specific attention and hard work of the following researchers.

At City of Palo Alto Utilities, we would like to acknowledge Karl Knapp, Taha Fattah, Tom Finch, and Debra Lloyd.

At the Center for Resource Solutions we would like to thank Ray Dracker, Katie McCormack, and Jennifer Martin.

At San Francisco Public Utilities Commission / Hetch Hetchy Water and Power we would like to acknowledge Fred Schwartz, Fred Weiner, and Bill Peden.

At the California Energy Commission we would like to thank Valentine Tiangco, Prab Sethi, and George Simons.

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 2 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: City of Palo Alto Utilities 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](http://www.energy.ca.gov/pier/reports.html) or contact the Energy Commission's Publications Unit at (916)-654-4628.
ABSTRACT

This case study presents the results of the second application of a renewable distributed generation assessment methodology conducted for City of Palo Alto Utilities (CPAU). CPAU is one of four distribution systems evaluated under the RDG Assessment project conducted under the auspices of the CEC PIER Renewables program. In addition to CPAU, the three other distribution systems evaluated include Alameda Power & Telecom (Alameda P&T), the 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, City of Palo Alto Utilities, avoided costs, reliability analysis, uncertainty analysis
# TABLE OF CONTENTS

Abstract ......................................................................................................................................................... v  

Executive Summary ...................................................................................................................................... 1  

City Of Palo Alto Utilities Case Study ........................................................................................................ 5  

1.0 Introduction ........................................................................................................................................... 5  

1.1. Background .......................................................................................................................................... 5  

1.1.1. Overview of Analysis ........................................................................................................................ 6  

1.2. Summary of Results for CPAU ............................................................................................................. 8  

1.2.1. Economic Screening Analysis ........................................................................................................ 8  

1.2.2. Engineering Screening Analysis ....................................................................................................... 9  

1.3. Report Organization ........................................................................................................................... 12  

2.0 Economic Screening Analysis .............................................................................................................. 13  

2.1. Avoided Costs .................................................................................................................................... 13  

2.1.1. General Avoided Cost Methodology ............................................................................................... 13  

2.1.2. Generation Avoided Costs ............................................................................................................. 14  

2.1.3. Transmission Avoided Costs ....................................................................................................... 18  

2.1.4. Distribution Avoided Costs ....................................................................................................... 18  

2.2. DG Economic Screening .................................................................................................................... 20  

2.2.1. Calculation of Costs and Benefits ............................................................................................... 24  

2.2.2. Results of Economic Screening Analysis ....................................................................................... 34  

2.3. Applying the RDG Screening Results ................................................................................................. 40  

3.0 Engineering Screening Analysis ........................................................................................................... 42  

3.1. Overview .......................................................................................................................................... 42  

3.2. Description of Analysis ..................................................................................................................... 44  

3.3. Power Flow Characteristics ............................................................................................................... 44  

3.3.1. Peak Load Snapshots .................................................................................................................... 44  

3.3.2. Annual Load Characteristics ..................................................................................................... 46  

3.4. RDG Siting Analysis ........................................................................................................................... 50  

vii
3.4.1. Small (100 kW) Test Generator ................................................................. 51
3.4.2. Large (2,000 kW) Test Generator ............................................................. 55
3.5. Comparison of Cases .................................................................................. 58
  3.5.1. Base Case (No RDG) .............................................................................. 58
  3.5.2. Reference Case 1: 10 MW of Distributed 500-kW Generators ............. 59
  3.5.3. Reference Case 2: 4 MW of Distributed PV .......................................... 60
3.6. Proposed RDG Cases .................................................................................. 64
  3.6.1. 570 kW Photovoltaic (PV) Solar At Selected Sites ............................... 64
  3.6.2. 730 kW Water Pump Regeneration ....................................................... 65
  3.6.3. 2 MW Combined Heat & Power (CHP) Near VA Hospital .................. 65
  3.6.4. 2 MW Peaking Generation Near VA Hospital ....................................... 66
  3.6.5. 10 MW CHP Generation Near VA Hospital ......................................... 67
  3.6.6. 10 MW CHP Generation on QR Substation ......................................... 69
3.7. Voltage Change Impact Screen .................................................................. 69
3.8. Overcurrent Protection Impact Screen ....................................................... 71
3.9. Annual Energy Simulation Comparison .................................................... 73
3.10. Observations ............................................................................................. 74
4.0 Load and Resource Analysis ......................................................................... 76
  4.1. Local Area Load Shapes .......................................................................... 76
  4.2. RDG Output Characteristics ..................................................................... 77
  4.3. Summaries of Demands and Savings ......................................................... 77
    4.3.1. Reference Case 1: 10 MW CHP Generation Characteristics ............... 79
    4.3.2. Photovoltaic Characteristic ................................................................. 81
    4.3.3. 570 kW Solar Photovoltaic Case ........................................................ 84
    4.3.4. 730 kW Water Pump Regeneration ..................................................... 86
    4.3.5. 2 MW Combined Heat & Power (CHP) Near VA Hospital ................. 88
    4.3.6. 2 MW Peaker Near VA Hospital .......................................................... 89
    4.3.7. 10 MW CHP Near VA Hospital ............................................................ 91
    4.3.8. 10 MW CHP Near QR Substation ....................................................... 92
6.4. Distribution Avoided Costs ................................................................. 139
6.5. RDG Capital Costs, Fuel Costs, and Capacity Factors .................... 140
6.6. Results of Uncertainty Analysis ......................................................... 140
   6.6.1. 5MW Biogas ................................................................. 140
   6.6.2. 50 kW Solar PV .............................................................. 142
   6.6.3. 1.5 MW Wind Generator .................................................. 144
6.7. Renewable Generation Premium ...................................................... 146
   6.7.1. Effect on the cost tests ....................................................... 147
   6.7.2. Results with inclusion of renewable premium ........................... 147
7.0 Conclusions ....................................................................................... 150
References .............................................................................................. 152
Glossary ................................................................................................. 154
APPENDIX A: COST AND PERFORMANCE OF RENEWABLE DG TECHNOLOGIES ............ A
## LIST OF FIGURES

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Figure 1</td>
<td>CEC PIER Program Research Project Structure</td>
<td>1</td>
</tr>
<tr>
<td>Figure 2</td>
<td>RDG Analysis Process Diagram</td>
<td>7</td>
</tr>
<tr>
<td>Figure 3</td>
<td>Net Benefit Range For Key Uncertainties From The TRC Test Perspective</td>
<td>9</td>
</tr>
<tr>
<td>Figure 4</td>
<td>Power Flow In The CPAU System</td>
<td>10</td>
</tr>
<tr>
<td>Figure 5</td>
<td>Optimal Locations For Small Generation (100 Kw) On The CPAU System With</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td>Respect To Reducing Peak Load Losses</td>
<td></td>
</tr>
<tr>
<td>Figure 6</td>
<td>Optimal Locations For Large RDG (2 MW) With Respect To Loss Reduction At</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>Peak Load</td>
<td></td>
</tr>
<tr>
<td>Figure 7</td>
<td>Avoided Generation Costs</td>
<td>16</td>
</tr>
<tr>
<td>Figure 8</td>
<td>Comparison Of Base, High, And Low Scenarios For Avoided Generation Costs</td>
<td>17</td>
</tr>
<tr>
<td>Figure 9</td>
<td>Potential Indirect Benefits Of RDG Installation</td>
<td>33</td>
</tr>
<tr>
<td>Figure 10</td>
<td>Cost Test Results For 800 Kw Biogas Caterpillar W/CHP</td>
<td>36</td>
</tr>
<tr>
<td>Figure 11</td>
<td>Cost Test Results For 800 Kw Biogas Caterpillar Without CHP</td>
<td>37</td>
</tr>
<tr>
<td>Figure 12</td>
<td>Cost Test Results For 50 Kw Solar PV</td>
<td>38</td>
</tr>
<tr>
<td>Figure 13</td>
<td>Cost Test Results For 10 Kw Wind Generator</td>
<td>39</td>
</tr>
<tr>
<td>Figure 14</td>
<td>Test Results For 1.5 MW Wind Generator</td>
<td>40</td>
</tr>
<tr>
<td>Figure 15</td>
<td>Power Flow in CPAU Distribution System</td>
<td>45</td>
</tr>
<tr>
<td>Figure 16</td>
<td>Circuit Plot With Line Section Thickness Proportional To Losses</td>
<td>45</td>
</tr>
<tr>
<td>Figure 17</td>
<td>Annual Energy Load Shape</td>
<td>47</td>
</tr>
<tr>
<td>Figure 18</td>
<td>Annual Energy Loss Shape</td>
<td>47</td>
</tr>
<tr>
<td>Figure 19</td>
<td>Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At</td>
<td>49</td>
</tr>
<tr>
<td></td>
<td>150 MW Load Level</td>
<td></td>
</tr>
<tr>
<td>Figure 20</td>
<td>Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At</td>
<td>49</td>
</tr>
<tr>
<td></td>
<td>195 MW Load Level</td>
<td></td>
</tr>
<tr>
<td>Figure 21</td>
<td>Darker colors indicate more optimal locations for small generation (100 kW) on</td>
<td>51</td>
</tr>
<tr>
<td></td>
<td>CPAU system with respect to reducing peak load losses</td>
<td></td>
</tr>
<tr>
<td>Figure 22</td>
<td>Darker colors indicate more optimal locations for small DG (100 kW) with</td>
<td>53</td>
</tr>
<tr>
<td></td>
<td>respect to releasing distribution capacity</td>
<td></td>
</tr>
<tr>
<td>Figure 23</td>
<td>Darker colors indicate less optimal locations for small DG (100 kW) with</td>
<td>53</td>
</tr>
<tr>
<td></td>
<td>respect to releasing distribution capacity</td>
<td></td>
</tr>
</tbody>
</table>
Figure 67: Capacity Increase With Respect To EEN For 4 MW Of Solar Photovoltaic Generation Uniformly Distributed Throughout The System (Reference Case 2)......109

Figure 68: Capacity Increase With Respect To Losses For 4 MW Of Solar Photovoltaic Generation Uniformly Distributed Throughout The System (Reference Case 2)......110

Figure 69: Depiction Of The Impact Of The Generation In Reference Case 2 (4 MW Solar PV) On The Peak Hourly EEN As Compared To The Base Case.................................................111

Figure 70: Depiction Of The Impact Of The Generation In Reference Case 2 (4 MW Solar PV) On The Total EEN As Compared To The Base Case.................................................111

Figure 71: Comparison Of CPAU Load Shape And Assumed Output Of Solar PV Generation For A Typical Summer Week .................................................................112

Figure 72: Capacity Comparison Based On EEN Of Proposed CPAU Solar PV Case With The Base Case...............................................................................................................114

Figure 73: Capacity Comparison (Based On Primary Losses) Of Proposed CPAU Solar PV Case With The Base Case..............................................................................................115

Figure 74: Capacity Comparison, Based On EEN, Of Proposed CPAU Regenerative Pumping Case With The Base Case..........................................................................................117

Figure 75: Capacity Comparison, Based On Losses, Of Proposed CPAU Regenerative Pumping Case With The Base Case..........................................................................................117

Figure 76: Capacity Comparison, Based On EEN, Of 2 MW Of CHP Generation Near The VA Hospital With The Base Case..........................................................................................118

Figure 77: Capacity Comparison, Based On Losses, Of 2 MW Of CHP Generation Near The VA Hospital With The Base Case..........................................................................................119

Figure 78: Dispatch Characteristic Assumed For The 2 MW Peaking Generation ........120

Figure 79: Capacity Comparison, Based On EEN, Of 2 MW Of Peaking Generation Located Near The VA Hospital With The Base Case.............................................................................121

Figure 80: Capacity Comparison, Based On Losses, Of 2 MW Of Peaking Generation Located Near The VA Hospital With The Base Case.............................................................................121

Figure 81: Capacity Comparison, Based On EEN, Of 10 MW Of Peaking Generation Located Near The VA Hospital With The Base Case.............................................................................122

Figure 82: Capacity Comparison, Based On Losses, Of 10 MW Of Peaking Generation Located Near The VA Hospital With The Base Case.............................................................................122

Figure 83: Capacity Comparison, Based On EEN, Of 10 MW Of CHP Generation Located Near The QR Substation With The Base Case.................................................................124

Figure 84: Capacity Comparison, Based On Losses, Of 10 MW Of CHP Generation Located Near The QR Substation With The Base Case.................................................................124

Figure 85: Capacity Comparison, Based On EEN, Of 10 MW Of Peaking Generation Located Near The VA Hospital With The Base Case.............................................................................123

Figure 86: Capacity Comparison, Based On Losses, Of 10 MW Of Peaking Generation Located Near The QR Substation With The Base Case.................................................................124
Figure 87: Comparison Of EEN Versus MW Load Computed For All Cases......................125
Figure 88: Comparison Of Annual Losses Versus MW Load For All Cases......................126
Figure 89: Typical Range Of Reported Values For Customer Value Of Service (VOS)......129
Figure 90: RDG Assessment Analysis Process Flow Diagram...........................................132
Figure 91: EEN-Based T&D Deferral ..................................................................................133
Figure 92: VRI and T&D Deferral.......................................................................................134
Figure 93: Comparison Of Base, High, And Low Avoided Generation Costs.................139
Figure 94: Net benefit range for key uncertainties from the TRC test perspective ............140
Figure 95: Sensitivity Analysis For 5 MW Biogas Generator From The TRC Test
Perspective.........................................................................................................................141
Figure 96: Range Of Net Benefits For 50 Kw Solar PV From The TRC Test Perspective ...143
Figure 97: Sensitivity Analysis For 50 Kw Solar PV From The TRC Test Perspective ......144
Figure 98: Range Of Net Benefits For A 1.5 MW Wind Generator From The TRC Test
Perspective............................................................................................................................145
Figure 99: Sensitivity Analysis For 1.5 MW Wind Generator From The TRC Test
Perspective............................................................................................................................146

**LIST OF TABLES**

Table 1: Benefit/Cost Ratio Results for CPAU RDG Screening Analysis (using base-case
economic assumptions).........................................................................................................8
Table 2: Avoided generation cost forecast method by period .............................................14
Table 3: Screening Model Generation Avoided Cost Inputs..............................................16
Table 4: Time-Of-Use Period Definitions ...........................................................................16
Table 5: Distribution Avoided Cost Calculation Inputs......................................................20
Table 6: Questions addressed by the various cost tests ......................................................22
Table 7: Benefits and costs of various test perspectives included in our modeling..........23
Table 8: Performance Characteristics For RDG Technologies And DG Operating Using
Renewable Fuels....................................................................................................................25
Table 9: 2004 RDG fuel prices ...........................................................................................26
Table 10: Generation benefits by test perspective..............................................................27
Table 11: Rates used in analysis..........................................................................................28
Table 12: Results of CPAU RDG screening, under base-case assumptions .........................35
Table 13: Voltage drop for different amounts of DG distributed as shown in Figure 16 ....62
Table 14: Maximum voltage change for generator on/off ..................................................70
Table 15: Comparative Impacts of The Various DG Options on Overcurrent Protection of CPAU System ..................................................................................................................71
Table 16: Comparison of Annual Energy Savings for DG Options .................................73
Table 17: Comparison Of Annual and Peak Loss Savings for DG Options ....................74
Table 18: Purchased Power and Demand Savings .............................................................78
Table 19: Annual Loss Savings .........................................................................................78
Table 20: Loss Savings at Peak Load ..............................................................................79
Table 21: Mid-range customer value of service (VOS) estimates ..................................130
Table 22: Value of Reliability Improvement (Year 2004) ...............................................131
Table 23: Results Of RDG Screening Under Base Case Assumptions, Without Inclusion Of Renewable Premium ........................................................................................................148
Table 24: Results Of RDG Screening Under Base Case Assumptions, With Inclusion Of Renewable Premium ........................................................................................................149
EXECUTIVE SUMMARY

Introduction

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

Figure 1: CEC PIER Program Research Project Structure

The following discussion comprises 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 City of Palo Alto Utilities (CPAU) distribution system. The analysis results for the remaining three municipal utilities are provided as separate cases study reports for the San Francisco Public Utilities Commission/ Hetch Hetchy (SF PUC), Alameda Power and Telecom (Alameda P&T), and 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 Renewable Distributed Generation Assessment project is to develop a sound and replicable methodology for evaluating RDG within a utility planning process. The methodology developed jointly by E3 and ETK was applied in four municipal utility case studies throughout Northern California with the goal of facilitating the installation of cost-effective RDG systems in California.

The core contributions of this research include the following:

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

Project Objective

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

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

The results of the CPAU 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 CPAU 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:

1. CPAU has a compact distribution system with low losses.
2. Voltage changes from RDG switching on/off are within system tolerance boundaries.
3. No major system upgrades would be required with an RDG installation.
4. The most economically favorable RDG technologies on CPAU system are:
   5. 800 kW biogas-fueled internal combustion engine with CHP
   6. 3 MW biogas-fueled internal combustion engine with CHP
   7. Solar PV has a relatively high 60% coincidence factor in Palo Alto.
5. Some locations within the City can achieve 5% higher effective capacity boost by reducing losses during peak hours. However, if the generator is too large, a negative loss savings could result.
6. Specific optimal locations for RDG may change with the Alma substation closure.

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 CPAU 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.
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 – City of Palo Alto Utilities (CPAU). 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 CPAU RDG assessment. The CPAU 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 (CPAU), 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.

![RDG Analysis Process Diagram](image)

**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 CPAU

The results of our analysis for CPAU are described in detail in each chapter of the RDG Assessment Report 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.

The B/C ratio results calculated for four economic perspectives including (1) Total Resource Cost Test, (2) Participant Cost Test, (3) Ratepayer Impact Measure Test, and (4) Utility Cost Test are summarized in Table 1. The TRC calculates the net direct economic impact to the community of RDG installation and the Participant cost test measures the cost-effectiveness as if the Participant owns the RDG. The UCT is calculated assuming the RDG is utility-owned, while the RIM is calculated assuming the RDG is owned by the customer (refer to Economic Screening Memo for a more complete description of these cost tests). RDG technologies with a B/C ratio greater than 1.0 are cost-effective. Those with a B/C ratio close to 1.0 may warrant further evaluation.

Table 1: Benefit/Cost Ratio Results for CPAU RDG Screening Analysis (using base-case economic assumptions)

<table>
<thead>
<tr>
<th>Technology</th>
<th>TRC Cost Test</th>
<th>Participant (Customer or Merchant)</th>
<th>RIM Test (Customer Owned)</th>
<th>UCT Test (Utility Owned)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas - 10kW PEM Fuel Cell</td>
<td>0.01</td>
<td>0.02</td>
<td>0.71</td>
<td>0.01</td>
</tr>
<tr>
<td>Biogas - 10kW PEM Fuel Cell CHP</td>
<td>0.47</td>
<td>0.53</td>
<td>0.69</td>
<td>0.39</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell CHP</td>
<td>0.67</td>
<td>0.75</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 200kW PAF Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PAF Fuel Cell CHP</td>
<td>0.58</td>
<td>0.65</td>
<td>0.69</td>
<td>0.48</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>0.66</td>
<td>0.74</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell CHP</td>
<td>0.49</td>
<td>0.55</td>
<td>0.69</td>
<td>0.40</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine</td>
<td>0.03</td>
<td>0.04</td>
<td>0.71</td>
<td>0.03</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine w/ CHP</td>
<td>0.79</td>
<td>0.88</td>
<td>0.69</td>
<td>0.63</td>
</tr>
<tr>
<td>Biogas - 500 kW Gas Recip GA-K-500</td>
<td>0.07</td>
<td>0.07</td>
<td>0.71</td>
<td>0.06</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.09</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE w/CHP</td>
<td>1.31</td>
<td>1.47</td>
<td>0.69</td>
<td>0.99</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.10</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE w/CHP</td>
<td>1.34</td>
<td>1.50</td>
<td>0.69</td>
<td>1.01</td>
</tr>
<tr>
<td>Biogas - 5MW Wartsila 5238 LN</td>
<td>0.90</td>
<td>1.01</td>
<td>0.69</td>
<td>0.66</td>
</tr>
<tr>
<td>Biogas - MSW Gassification</td>
<td>0.50</td>
<td>0.35</td>
<td>0.72</td>
<td>0.58</td>
</tr>
<tr>
<td>Biodiesel - 500kW DE-K-500</td>
<td>0.15</td>
<td>0.16</td>
<td>0.72</td>
<td>0.13</td>
</tr>
<tr>
<td>Solar - PV-5 kW</td>
<td>0.21</td>
<td>0.16</td>
<td>0.83</td>
<td>0.20</td>
</tr>
<tr>
<td>Solar - PV-50 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - PV-100 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - Thermal SAIC SunDish 25 kW</td>
<td>0.18</td>
<td>0.14</td>
<td>0.30</td>
<td>0.30</td>
</tr>
<tr>
<td>Wind - Bergey WD -10kW</td>
<td>0.16</td>
<td>0.18</td>
<td>0.66</td>
<td>0.16</td>
</tr>
<tr>
<td>Wind - GE 750 kW</td>
<td>0.91</td>
<td>0.91</td>
<td>1.63</td>
<td></td>
</tr>
<tr>
<td>Wind - GE 1.5 MW</td>
<td>1.08</td>
<td>1.08</td>
<td>1.91</td>
<td></td>
</tr>
</tbody>
</table>
For each of the technologies in Table 1, we analyzed the sensitivity of results to uncertainties in the underlying assumptions. Figure 3 shows an example: the range of the TRC test results (net benefits) for the biogas 5 MW generator in $/kW for six key variables. This range shows that while the net benefit is negative under the base case scenario, changes in these key variables can lead to a cost-effective result with either the High transmission cost or Low fuel cost scenario.

![Range of DG Net Benefit for Key Uncertainties](image)

**Figure 3: Net Benefit Range For Key Uncertainties From The TRC Test Perspective**

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

In this study, a 100-kW test generator was used for the small unit size and 2,000 kW (2 MW) for the large size. The 100-kW unit is small relative to the capacity of any of the feeders and lateral branches, and 2 MW was chosen as the largest practical size, given system characteristics.

Figure 5 depicts the results for optimal location of a small generator with regard to reducing peak load losses. The darkest-colored bus locations represent the top 25% with respect to loss reduction. The lightest color represents the lowest 50%.

At the 195 MW loading level, the computed loss improvement varied from essentially 0 to 9.5% of the generator’s capacity (max of 9.5 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 marginal improvement declines for subsequent generators added in the same general area.

The analysis was repeated for a large generator (2 MW). This value was chosen because it is approximately 50% of the capacity of a 4 kV feeder. While the 100 kW generators resulted in reduced losses in all distribution system locations, a 2 MW generator would be expected to actually increase the losses in some locations. This may seem counter-intuitive, but there is a limit to what one can place on a particular system without causing increased losses in some locations, without making modifications to the distribution system.

That is indeed what we find with this analysis. The range of loss reduction at peak load is from 7% of the generator size (14 kW) to a 6% (12 kW) increase in losses. Figure 6 shows the optimal locations with respect to losses, with the darker colors representing more optimal locations.
1.3. Report Organization

This report is organized in the following manner:

- Section 1.0 Introduction
- Section 2.0 Economic Screening Analysis
- Section 3.0 Engineering Screening Analysis
- Section 4.0 Load and Resource Analysis
- Section 5.0 Reliability Analysis
- Section 6.0 Uncertainty Analysis
- Section 7.0 Conclusions

There is one Appendix.

Appendix A. Cost and Performance of Renewable DG Technologies
2.0 Economic Screening Analysis

The aim of our RDG analysis is to identify technologies that hold the potential for cost-effective installation in the CPAU service territory. For the purposes of this analysis, RDG is deemed cost-effective if it yields positive net benefits:

\[
\text{Net Benefits} = \text{Benefits} - \text{Costs}
\]

Most of the benefits associated with RDG in the above equation are comprised of avoided costs, which are 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 an action under consideration, such as installing RDG technology. Thus, avoided costs can be thought of as the benchmark for cost-effectiveness evaluation of RDG technologies. If the avoided costs (the costs the utility would have incurred in the absence of RDG) are greater than the RDG costs, the RDG technology is cost-effective.

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 CPAU’s service territory. The actual comparison of benefits (avoided costs and other benefits) and costs (installed and operating costs of RDG) are addressed in the Economic Screening section.

This section is organized as follows:

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

2.1.1. General Avoided Cost Methodology

Throughout this analysis, we have drawn on information obtained from CPAU and publicly available data sources to calculate avoided costs within CPAU’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) CPAU’s service territory make up the bulk of the avoided costs. Solar photovoltaic DG, for example, may reduce the utility’s energy purchases from the market, reduce associated transmission costs, and defer load growth related expansion of the system.

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

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

2.1.2. 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.

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

<table>
<thead>
<tr>
<th>Period</th>
<th>Generation Cost Forecast Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004 -2006</td>
<td>Electricity Forward Price Quotes</td>
</tr>
<tr>
<td>2007</td>
<td>Gas Futures and Heat Rate</td>
</tr>
<tr>
<td>2008 and Beyond</td>
<td>Long Run Marginal Cost (LRMC)</td>
</tr>
</tbody>
</table>

Any electricity price forecast may be substituted for our avoided costs forecast, though care should be taken to ensure the price reflects delivery to the CPAU system. Broker quotes offered directly to CPAU are an excellent substitute for our avoided generation forecast for all years in which they are available. Generation market prices could be updated with broker quotes and other information as available to CPAU.


Through 2006, we base our market price forecast on forward price quotes from Platts’ Megawatt Daily. The price quotes reported by Platts are for the peak period. We estimate the off-peak price to be 67% of the on-peak price, based on the historical relationship between peak and off-peak spot market prices.
Gas Price and Heat Rate of CCGT: 2007

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

One way around this price discrepancy is to look at the implied heat rate of the marginal generating unit. In a competitive market with excess supply, the price of electricity should equal the marginal cost of producing it. For a gas fired generator, the marginal cost of production is determined by the gas price and the heat rate of the generator. We can, therefore, calculate the implied heat rate for the marginal generating unit in 2006, when both gas futures and electricity forward prices are available.

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

Long Run Marginal Cost (LRMC): 2008 and Beyond

In a period of system load and resource balance with a competitive marketplace for generation the price of electricity can be expected to equal the 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. A key driver of CCGT cost is, of course, the cost of gas. We rely on NYMEX natural gas futures, which are available through 2009, and the CEC’s gas forecast beyond 2009 for our gas price estimates.

2.1.2.2. Generation Avoided Cost Results

Table 3 shows the first 10 years of generation avoided cost inputs in E3’s screening model. This is a direct relationship whereby the actual market price of electricity equals the costs avoided through the acquisition of RDG resources. The data represent E3’s base case electricity price forecast, calculated as described above.
### Table 3: Screening Model Generation Avoided Cost Inputs

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td></td>
<td>$50.47</td>
<td>$52.32</td>
<td>$52.82</td>
<td>$51.42</td>
<td>$60.70</td>
<td>$66.88</td>
<td>$62.02</td>
<td>$64.15</td>
<td>$66.18</td>
<td>$68.56</td>
<td>$70.92</td>
<td>$73.35</td>
</tr>
<tr>
<td>Off-Peak</td>
<td></td>
<td>$33.81</td>
<td>$35.06</td>
<td>$35.39</td>
<td>$34.45</td>
<td>$40.67</td>
<td>$44.81</td>
<td>$41.55</td>
<td>$42.98</td>
<td>$44.34</td>
<td>$45.93</td>
<td>$47.51</td>
<td>$49.15</td>
</tr>
</tbody>
</table>

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

### Table 4: Time-Of-Use Period Definitions

<table>
<thead>
<tr>
<th>TOU Period</th>
<th>Definition</th>
<th># of Hours in Period</th>
<th>% of Hours in Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>Mon-Sat, 6:00 AM to 10:00 PM (6x16), except holidays</td>
<td>4864</td>
<td>56%</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>All other hours</td>
<td>3896</td>
<td>44%</td>
</tr>
</tbody>
</table>

Generation avoided costs are shown in Figure 7 along with the 20-year levelized stream for both the peak and off-peak periods.

![Avoided Generation Costs](image)

Figure 7: Avoided Generation Costs

16
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 $67.86/MWh in the peak period and $45.47 in the off-peak period.

In Table 3 and Figure 7, one can observe a slight dip in forecast prices in 2007. This is a result of gas futures prices being lower for 2007 than for 2006. There is another, larger dip in 2010. Since gas futures are available only through 2009, beginning in 2010 we use the CEC gas price forecast, which is low compared to recent gas futures prices.

We also calculated “high” and “low” price scenarios for avoided generation costs. In our base case forecast, electricity prices for the years 2004 – 2009 are given by either forward electricity prices or natural gas futures prices and the cost of production. Since these are forward contracts that a utility can buy, the forecast represents a fully hedged position. For this reason, we hold the first 5 years of the forecast constant for the base case, high, and low scenarios. After 2009, when the forecast is based on the CEC’s gas forecast and the cost of production, we use the CEC’s high and low gas price forecasts to calculate our high and low electricity price forecast. As with the base case, the price is based on the full cost of operating a CCGT.

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

![Comparison of Base, High, and Low Avoided Generation Costs](image_url)

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

In the Uncertainty Analysis chapter, 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 as CPAU, consist of transmission charges paid to other entities that the utility would not have to pay if it had sufficient in-area generation to meet its load.

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

As of the date of this analysis, CPAU’s transmission charges are $9.16/MWh. CPAU resource staff feels it is highly unlikely that transmission charges will be reduced in the near future, so this makes up our 'low' scenario forecast.

Our 'base case' value assumes that transmission charges increase by 10% in 2006 to $10.07/MWh.

The 'high' scenario is subject to greater uncertainty. Under Locational Marginal Pricing (LMP), proposed by the California ISO for implementation in 2005, 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 Palo Alto - and the Bay Area in general - are characterized by high transmission congestion, the effects of the proposed change could be quite severe. CPAU did not provide an estimate of the potential range of future transmission costs. In lieu of this information, we have assumed a value of $20/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.

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 threshold level that would otherwise trigger 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 utility’s revenue requirement under the base case plan (no RDG) is compared with the plan with RDG on a present value basis. We use the term
'revenue requirement' to stress that it is not just the engineering costs of each case that are compared, but the fully loaded project costs, including maintenance, administrative costs, insurance, etc.

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

\[
MC[PW] = \sum \frac{\text{Invest} \cdot (1 + i)^r}{(1 + r)^y} \cdot \frac{\text{LoadChange}}{\text{LoadChange}} \cdot \text{Annualization Factor}
\]

where:

- **Invest** = annual demand-related investments in capacity by area (§)
- **i** = escalation rate for the investments
- **r** = discount rate; **y** = year
- **LoadChange** = estimated average change in peak load by area for the planning period
- **Δy** = deferral caused by load change (annual peak load growth divided by **LoadChange**)
- **Annualization Factor** = real economic carrying charge for the planning period, grossed up by a variable expense factor

We use a spreadsheet-based model to calculate the specific avoided costs values relevant to CPAU. The basic model inputs are shown in Table 5.
### Table 5: Distribution Avoided Cost Calculation Inputs

<table>
<thead>
<tr>
<th>Model Input</th>
<th>Unit</th>
<th>Additional Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned investments</td>
<td>$</td>
<td>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.</td>
</tr>
<tr>
<td>Timing of investments</td>
<td>Year/Month</td>
<td>This is the time period within which the decision to build or not-build would be made.</td>
</tr>
<tr>
<td>Minimum load deferral amount</td>
<td>MW</td>
<td>The minimum amount of load that needs to be deferred through an alternative option to avoid construction of the base-case project.</td>
</tr>
<tr>
<td>Load growth forecast</td>
<td>MW/year</td>
<td>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</td>
</tr>
<tr>
<td>Investment discount rate</td>
<td>%</td>
<td>This is the discount rate used by the local distribution company for investment also known as the weighted average cost of capital (WACC)</td>
</tr>
<tr>
<td>Interest rate</td>
<td>%</td>
<td>This should be the interest rate that is used in internal investment evaluations.</td>
</tr>
</tbody>
</table>

#### 2.1.4.2. Distribution Avoided Cost Results

Through our data collection efforts, we learned that CPAU has no planned investments at the distribution level. Therefore, there are no distribution costs to avoid and this value is equal to 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 one element of the total benefits of RDG installation; total benefits are compared to total costs of RDG to determine RDG’s cost-effectiveness. In this memo, we provide a description of the inputs, methodology, and results from our analysis of multiple RDG technologies that could be installed within or nearby CPAU’s 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.** This test measures the economic impact to the RDG owner.
- **Ratepayer Impact Measure (RIM).** This test measures the impact on utility operating margin and whether rates would have to increase to maintain the current levels if a customer installed RDG.
- **Utility Cost Test (UCT).** This test 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).** This test measures the net direct economic impact to the community.
- **Societal Cost Test.** This test measures the net economic benefit to the community, as measured by the TRC, plus indirect benefits such as environmental benefits.

A common misperception is that there is a single best perspective for evaluation of cost-effectiveness. Each test is accurate, but the results of each test 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 6.
Table 6: Questions addressed by the various cost tests

<table>
<thead>
<tr>
<th>Participant Cost Test</th>
<th>10. Is it worth it to the customer to install RDG?</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>11. Is the customer likely to want to participate in a utility program that promotes RDG?</td>
</tr>
<tr>
<td>Ratepayer Impact Measure</td>
<td>12. What is the impact of the RDG project on the utility’s operating margin?</td>
</tr>
<tr>
<td></td>
<td>13. Would the project require an increase in rates to reach the same operating margin?</td>
</tr>
<tr>
<td>Utility Cost Test</td>
<td>14. Do total utility costs increase or decrease?</td>
</tr>
<tr>
<td></td>
<td>15. What is the change in total customer bills required to keep the utility whole (the change in revenue requirement)?</td>
</tr>
<tr>
<td>Total Resource Cost Test</td>
<td>16. What is the community benefit of the RDG project including the net costs and benefits to the utility and its customers?</td>
</tr>
<tr>
<td></td>
<td>17. Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)?</td>
</tr>
<tr>
<td></td>
<td>18. Is more or less money required by the community to pay for energy needs?</td>
</tr>
<tr>
<td>Societal Cost Test</td>
<td>19. What is the overall benefit to the community of the RDG project, including indirect benefits?</td>
</tr>
<tr>
<td></td>
<td>20. 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)?</td>
</tr>
</tbody>
</table>

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

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

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

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

2.2.1.2. 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 8 shows the key RDG performance characteristics and cost data we used in our analysis. We used publicly available information on commercially available technologies. Additional information on RDG technologies is available in Appendix A.
Table 8: Performance Characteristics For RDG Technologies And DG Operating Using Renewable Fuels

<table>
<thead>
<tr>
<th>Technology Name</th>
<th>Non Municipal Incentives / Tax Credits $/kW</th>
<th>Municipal Utility Incentive Cost $/kW</th>
<th>Generator Life (Years)</th>
<th>Fuel Type: (1) No Cost (solar, hydro, wind) (2) Biodiesel 80/20 (3) MSW Delivery and Processing (4) Landfill Gas (5) Other Renewable Fuel</th>
<th>Heat Rate (Net Heat Rate for CHP Applications)</th>
<th>Capital Cost $/kW</th>
<th>Install Cost $/kW</th>
<th>Fixed O&amp;M $/kW</th>
<th>Variable O&amp;M $/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas - 10kW PEM Fuel Cell</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>12,507</td>
<td>$5,500</td>
<td>0</td>
<td>$18.00</td>
<td>$0.03</td>
</tr>
<tr>
<td>Biogas - 10kW PEM Fuel Cell CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>7,007</td>
<td>$5,500</td>
<td>0</td>
<td>$18.00</td>
<td>$0.03</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>8,338</td>
<td>$3,500</td>
<td>0</td>
<td>$10.00</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>5,731</td>
<td>$3,500</td>
<td>0</td>
<td>$10.00</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>10,428</td>
<td>$4,500</td>
<td>0</td>
<td>$6.50</td>
<td>$0.03</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>5,346</td>
<td>$4,500</td>
<td>0</td>
<td>$6.50</td>
<td>$0.03</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>10,725</td>
<td>$3,600</td>
<td>0</td>
<td>$6.50</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>5,775</td>
<td>$3,600</td>
<td>0</td>
<td>$6.50</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 250kW SOFC Fuel Cell</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>8,723</td>
<td>$5,000</td>
<td>0</td>
<td>$5.00</td>
<td>$0.04</td>
</tr>
<tr>
<td>Biogas - 250kW SOFC Fuel Cell CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>6,303</td>
<td>$5,000</td>
<td>0</td>
<td>$5.00</td>
<td>$0.04</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>15,443</td>
<td>$2,201</td>
<td>0</td>
<td>$0.00</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine w/ CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>5,573</td>
<td>$2,604</td>
<td>0</td>
<td>$0.00</td>
<td>$0.02</td>
</tr>
<tr>
<td>Biogas - 500 kW Gas Recip GA-K-500</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>12,003</td>
<td>$936</td>
<td>0</td>
<td>$26.50</td>
<td>$0.00</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>10,246</td>
<td>$724</td>
<td>0</td>
<td>$0.00</td>
<td>$0.01</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE w/CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>4,771</td>
<td>$971</td>
<td>0</td>
<td>$0.00</td>
<td>$0.01</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>9,492</td>
<td>$702</td>
<td>0</td>
<td>$0.00</td>
<td>$0.01</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE w/CHP</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>4,857</td>
<td>$864</td>
<td>0</td>
<td>$0.00</td>
<td>$0.01</td>
</tr>
<tr>
<td>Biogas - 5MW Wartsila 5238 LN</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>4</td>
<td>8,758</td>
<td>$727</td>
<td>0</td>
<td>$0.00</td>
<td>$0.01</td>
</tr>
<tr>
<td>Biogas - MSW Gassification</td>
<td>$0</td>
<td>$0</td>
<td>15</td>
<td>3</td>
<td>8,000</td>
<td>$5,179</td>
<td>0</td>
<td>$20.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Biodiesel - 500kW DE-K-500</td>
<td>$0</td>
<td>$0</td>
<td>12.5</td>
<td>2</td>
<td>10,314</td>
<td>$386</td>
<td>0</td>
<td>$26.50</td>
<td>$0.00</td>
</tr>
<tr>
<td>Solar - PV-V kW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$8,650</td>
<td>0</td>
<td>$14.30</td>
<td>$0.00</td>
</tr>
<tr>
<td>Solar - PV-50 kW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$6,675</td>
<td>0</td>
<td>$5.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Solar - PV-100 kW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$6,675</td>
<td>0</td>
<td>$2.85</td>
<td>$0.00</td>
</tr>
<tr>
<td>Solar - Thermal SAIC SunDish 25 kW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$5,700</td>
<td>0</td>
<td>$20.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Wind - Bergey WD -10kW</td>
<td>$0</td>
<td>$0</td>
<td>10</td>
<td>1</td>
<td>0</td>
<td>$6,055</td>
<td>0</td>
<td>$5.70</td>
<td>$0.00</td>
</tr>
<tr>
<td>Wind - GE 750 kW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$1,200</td>
<td>0</td>
<td>$15.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Wind - GE 1.5 MW</td>
<td>$0</td>
<td>$0</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>$1,000</td>
<td>0</td>
<td>$15.00</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

* Additional information on RDG technologies is available in Appendix A.
For those technologies that operate with an external fuel source, such as reciprocating engines or fuel cells, we have included distinct fuel prices for several renewable fuels and the prices that are used to calculate their operating costs in the model. These fuel prices are shown in Table 9.

<table>
<thead>
<tr>
<th></th>
<th>2004 RDG fuel prices</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biodiesel 80/20</td>
<td>$8.58</td>
</tr>
<tr>
<td>MSW Delivery and Process</td>
<td>$8.00</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>$9.50</td>
</tr>
</tbody>
</table>

The fuel costs shown in Table 9 are escalated at a rate of 2% per year in our analysis. The biodiesel cost of $8.58/MMBtu is based on a cost of $1.26 per gallon. Although the cost of biodiesel depends on the market price of vegetable oil, a rule of thumb is that B20 biodiesel is $0.20/gallon more expensive than regular diesel fuel. Diesel fuel spot prices in the Western U.S. are currently abnormally high (roughly $1.25/gallon in Los Angeles, implying a biodiesel cost of roughly $1.45/gallon), but we believe that for this long-term planning analysis, a more “normal” value of roughly $1/gallon is more reasonable.

Landfill gas is free, but capturing it involves capital costs of $6-13/MMBtu/year and O&M costs of 13-74 cents/MMBtu/year, according to an EPA presentation from the Landfill Methane Outreach Program. Similarly, municipal solid waste (MSW) is free, and plentiful, but the gasification process results in an overall cost not included in the capital and O&M cost of a generator. The MSW costs included in our model are based upon vendor quotes for the gasification process but can vary depending upon the waste streams and system configuration. To address this issue of cost variation, we test the impact of changes in fuel cost in the Uncertainty Analysis (Del. 3.1.4.7) and are able to observe any changes in RDG cost-effectiveness resulting from higher or lower fuel costs.

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 DG program.

### 2.2.1.3. 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 RDG on site, as shown in Table 10.

1 [http://www.eere.energy.gov/greenpower/conference/5gpmc00/tkerr.pdf](http://www.eere.energy.gov/greenpower/conference/5gpmc00/tkerr.pdf)
Table 10: Generation benefits by test perspective

<table>
<thead>
<tr>
<th>Value Basis</th>
<th>Calculation</th>
<th>Participant Test</th>
<th>RIM Test</th>
<th>TRC Test</th>
<th>UCT (Utility owned DG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wholesale</td>
<td>Market prices x RDG output x Line Loss</td>
<td>Benefit (merchant plant)</td>
<td>Benefit</td>
<td>Benefit</td>
<td>Benefit</td>
</tr>
<tr>
<td>Retail</td>
<td>Rates x RDG output</td>
<td>Benefit (behind the meter installation)</td>
<td>Cost</td>
<td>Transfer</td>
<td>N/A</td>
</tr>
</tbody>
</table>

When evaluating the wholesale value of energy, we use the forecast of market electricity prices described in the generation avoided cost section (2.1.2.2). 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. 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.

The line loss factor in the wholesale generation calculation in Table 5 is a feedback from the results of the engineering analysis. This is included so that the benefits are captured for RDG installations that are particularly effective at reducing system losses.

No additional procurement or scheduling costs for in-area generation were included in calculating the generation costs and benefits.

An additional benefit for a dispatchable RDG technology that is not specifically calculated in this analysis is the ability to operate during periods with very high spot prices or during requests from the ISO for rotating outages. For those technologies that could be optimally dispatched with regard to market price signals, this additional benefit could be substantial. We have not modeled this benefit because it is highly dependent on exogenous factors that cannot be guaranteed to occur during an operating period and would not be a relevant measure in an economic cost-effectiveness screening analysis.

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.

---

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

Table 11 shows the residential, commercial, and industrial rates used in our analysis. These retail rates are based on electric rate estimates contained in the 10-year financial forecast as part of the proposed FY 03-05 budget dated 5/20/2003. The escalation factor was provided by CPAU; beyond 2009 rates are assumed to remain flat.

<table>
<thead>
<tr>
<th>Table 11: Rates used in analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Escalation and Expected Rate Changes</td>
</tr>
<tr>
<td>Residential $/kWh</td>
</tr>
<tr>
<td>Commercial $/kWh</td>
</tr>
<tr>
<td>Industrial $/kWh</td>
</tr>
</tbody>
</table>

2.2.1.4. Transmission Benefits

Transmission avoided costs for a municipal distribution utility are based on transmission charges paid to the transmission owner. As discussed in the Transmission Avoided Cost section, 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 delivered in order to produce the RDG output level of energy at the end-use. Since line losses may vary by TOU period, we perform this calculation by TOU period.

2.2.1.5. 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 Distribution Avoided Costs section.

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:

- RDG must have reliability at least as good as the conventional wires solution
- 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.

**2.2.1.6. 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 DG occur when the installed DG increases the reliability of the distribution system or prevents load shedding due to transmission or system capacity constraints. As described in the reliability analysis chapter, there are several methods of quantifying reliability benefits. In our analysis, we quantify reliability benefits using estimates of Value of Service (VOS) and Expected Unserved Energy (EUE). The VOS metrics serve as an annual value “proxy” to decide when to make additional investment based on the value to customers. However, CPAU does not use VOS directly to plan reliability-enhancing investments.

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. VOS values have historically been reported in the range of $5 to $30
dollars per kWh in survey studies but these values do not reflect a specific VOS survey conducted for California municipal utilities as part of this analysis. 3 4

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.

2.2.1.7. 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. An example is reduced tipping fees (solid waste disposal costs) for municipal solid waste (MSW) in the case where MSW would be used as a fuel source for RDG.

We model these benefits on a $/kWh produced value. For example, we set the reduced tipping fees resulting from MSW gasification at $0.01/kWh produced. This means that for every kWh of energy produced by MSW gasification RDG, waste disposal at a landfill would be reduced enough to reduce tipping fees by 1 cent. 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 RDG 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.


2.2.1.8. 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 DG 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 12. 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 Ratepayer Impact Measure (RIM) is calculated assuming the RDG is owned by the customer, while the Utility Cost Test is always calculated assuming utility ownership of the project. We do this because the Utility Cost Test perspective under customer ownership is not very revealing, since the utility enjoys the avoided cost savings without any of the ownership costs and the B/C ratio is always infinitely positive (in the absence of utility-paid incentives or other program costs).
<table>
<thead>
<tr>
<th>Description</th>
<th>TRC Cost Test</th>
<th>Participant (Customer or Merchant)</th>
<th>RIM Test (Customer Owned)</th>
<th>UCT Test (Utility Owned)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas - 10kW PEM Fuel Cell</td>
<td>0.01</td>
<td>0.02</td>
<td>0.71</td>
<td>0.01</td>
</tr>
<tr>
<td>Biogas - 10kW PEM Fuel Cell CHP</td>
<td>0.47</td>
<td>0.53</td>
<td>0.69</td>
<td>0.39</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>0.67</td>
<td>0.75</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 200kW PAF Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PAF Fuel Cell CHP</td>
<td>0.58</td>
<td>0.65</td>
<td>0.69</td>
<td>0.48</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>0.66</td>
<td>0.74</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell CHP</td>
<td>0.49</td>
<td>0.55</td>
<td>0.69</td>
<td>0.40</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine</td>
<td>0.03</td>
<td>0.04</td>
<td>0.71</td>
<td>0.03</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine w/ CHP</td>
<td>0.79</td>
<td>0.88</td>
<td>0.69</td>
<td>0.63</td>
</tr>
<tr>
<td>Biogas - 500 kW Gas Recip GA-K-500</td>
<td>0.07</td>
<td>0.07</td>
<td>0.71</td>
<td>0.06</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.09</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE w/CHP</td>
<td>1.31</td>
<td>1.47</td>
<td>0.69</td>
<td>0.99</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.10</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE w/CHP</td>
<td>1.34</td>
<td>1.50</td>
<td>0.69</td>
<td>1.01</td>
</tr>
<tr>
<td>Biogas - 5MW Wartsila 5238 LN</td>
<td>0.90</td>
<td>1.01</td>
<td>0.69</td>
<td>0.66</td>
</tr>
<tr>
<td>Biogas - MSW Gassification</td>
<td>0.50</td>
<td>0.35</td>
<td></td>
<td>0.58</td>
</tr>
<tr>
<td>Biodiesel - 500kW DE-K-500</td>
<td>0.15</td>
<td>0.16</td>
<td>0.72</td>
<td>0.13</td>
</tr>
<tr>
<td>Solar - PV-5 kW</td>
<td>0.21</td>
<td>0.16</td>
<td>0.83</td>
<td>0.20</td>
</tr>
<tr>
<td>Solar - PV-50 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - PV-100 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - Thermal SAIC SunDish 25 kW</td>
<td>0.18</td>
<td>0.14</td>
<td>0.30</td>
<td></td>
</tr>
<tr>
<td>Wind - Bergery WD -10kW</td>
<td>0.16</td>
<td>0.18</td>
<td>0.66</td>
<td>0.16</td>
</tr>
<tr>
<td>Wind - GE 750 kW</td>
<td>0.91</td>
<td>0.91</td>
<td></td>
<td>1.63</td>
</tr>
<tr>
<td>Wind - GE 1.5 MW</td>
<td>1.08</td>
<td>1.08</td>
<td></td>
<td>1.91</td>
</tr>
</tbody>
</table>

These screening results were calculated using base-case assumptions. Sensitivity of the results to varying input assumptions is discussed in the Uncertainty Analysis chapter as well as the effect of including a City Council authorized premium for renewable generation sources.

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 800 kW biogas Caterpillar engine with CHP is cost-effective from the TRC and Participant perspectives, nearly break-even from the UCT perspective, and not cost-effective from the RIM perspective.
The unit is cost-effective from the participant’s point of view because bill savings resulting from the installation exceed the associated costs. From the Utility perspective, the unit is not cost-effective because, although costs are similar to those experienced by the participant, savings are lower since the avoided costs experienced by the utility are lower than rates.

From the RIM test perspective, the savings in avoided generation and transmission costs resulting from the project are outweighed by the lost revenue in reduced customer bills, resulting in B/C ratio of 0.69. Installation of the unit by a customer would require the utility to raise rate in order to remain whole.

Looking at the TRC perspective, which is essentially the summation of the Participant and RIM perspectives, the technology is cost-effective by a fair margin, with a B/C ratio of 1.31.

Figure 11, which shows the same unit without CHP, illustrates the importance of CHP to the economics of the 800 kW Caterpillar generator. For this example, the operational characteristics are assumed to be identical to those for the unit with CHP (both are operating as baseload) and the savings are thus identical. But the costs are significantly higher for the non-CHP unit, as the heating fuel benefits for the CHP unit were reflected in a lower net heat rate.
Another example is shown in Figure 12 which displays the test results for 50 kW solar PV. This particular technology is not cost-effective from any of the test perspectives.
The primary driver of this result is the high capital cost of solar PV.

For the RIM test, capital costs are not an issue because they are a cost attributed to the participant. Nevertheless, because avoided costs are lower than the lost revenue from rates, the RIM test has a B/C ratio lower than 1.0, just as it did in the first example, and as it will in every case where this relationship between rates and avoided costs holds.

The results in Figure 13 mirror those in Figure 12. Like solar PV, the small wind unit has very high capital costs relative to the amount of energy produced, which results in a B/C ratio of less than 1.0. In the case of small wind, we assumed a capacity factor of 20%, which is higher than the wind speed in the Palo Alto area could support. Thus, drastic improvements in capital costs and/or technology efficiency would be required for small wind to be economical in the CPAU service area.

<table>
<thead>
<tr>
<th>Benefit, Cost, and Net Benefit (Levelized $/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td><code>$0.50</code></td>
</tr>
<tr>
<td><code>$0.30</code></td>
</tr>
<tr>
<td><code>$0.10</code></td>
</tr>
<tr>
<td><code>$0.00</code></td>
</tr>
<tr>
<td><code>$0.20</code></td>
</tr>
<tr>
<td><code>$0.40</code></td>
</tr>
</tbody>
</table>

**Figure 12: Cost Test Results For 50 Kw Solar PV**
In contrast, a 1.5 MW, large-scale wind unit has capital costs that compare much more favorably to the amount of energy produced. Figure 14 shows cost test results for a 1.5 MW wind unit, which is cost-effective from every perspective evaluated. These results were calculated with an assumed capacity factor of 30%, which is the generally the lowest threshold that the industry would consider economically viable. Palo Alto does not have the wind resources in-area to support a large wind installation because the local average wind speeds (approximately 4.5 m/s) are too low to yield a 30% capacity factor.

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 an alternative source of traditional generation, rather than distributed generation. Likewise, the Participant perspective assumes the participant is a merchant plant, rather than a customer. Benefits far exceed costs in the UCT in this case because the utility enjoys high savings relative to costs, without any reduction in revenues.
Referring back to Table 12, three of the technologies tested were shown to be cost-effective under the TRC. One is the large wind generator shown in Figure 14, which would be installed not as RDG, but as an alternative source of generation. The other two are large generators which rely on an effective CHP installation to become cost-effective. These results illustrate the difficulty of finding cost-effective RDG applications within CPAU’s service territory.

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 non-DG 1.5 MW wind generator, it is an excellent candidate for action – assuming a suitable installation site can be found. Similarly, an 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 CPAU 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 PV and small wind units, for example, provide benefits to the utility, but their costs so outweigh benefits from the participant perspective that these solutions appear to be non-starters. However, despite their high costs, customers do choose to install solar PV and small wind to meet other objectives, as discussed in the indirect benefits section. The large wind unit is desirable from all test perspectives, so there is no need to balance one test perspective against the other. The large wind generator is not an example of RDG that could be installed within the CPAU service territory, for reasons of both size and wind speed, but it is an example of a cost-effective renewable generation alternative.

The biogas unit in Figure 10 is somewhat more complex in terms of test results. It is clearly desirable from the participant perspective, as well as the TRC test perspective. However, as shown by the RIM test results, the installation will have a negative effect on other ratepayers. Should the utility push for installation of the unit 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 screening analysis performed on the CPAU distribution system to estimate the feasibility of accommodating distributed generation (DG) and the potential value of that generation to the benefit of the power delivery system. A particular emphasis was given to renewable DG (RDG).

There were six (6) basic cases considered:

1. 570 kW photovoltaic (PV) solar at selected sites,
2. 730 kW water pump regeneration,
3. 2 MW combined heat & power (CHP) near VA hospital,
4. 2 MW peaker near VA hospital,
5. 10 MW CHP near VA hospital,
6. 10 MW CHP near QR substation.

These were compared to two reference cases that represent what might be possible with various DG technologies:

Reference Case 1: 10 MW CHP optimally sited in 20 units of 500 kW each.
Reference Case 2: A total of 4 MW PV solar distributed throughout the system.

All of the proposed cases appear feasible without any major changes to the existing distribution system. The system is relatively compact with the exception of one feeder that serves the pumping stations to the south of the city. Thus, the losses are low and the voltage changes that occur when the generation suddenly connects or disconnects are within tolerance.

The two 10 MW CHP options have the potential to interfere with the utility overcurrent protection scheme on their respective feeders. Some relay settings may have to be changed to compensate for contributions from the generators to prevent nuisance tripping. It would be prudent to perform due diligence studies if DG applications of this size and nature are pursued.

10 MW is approximately the maximum size that should be considered on a 12 kV feeder. If the generation is more distributed, the system should accommodate at least 25 MW without having to make significant changes. The CPAU system is perhaps better able to accommodate DG than most distribution system because the feeders are relatively compact.

Optimal siting analysis with respect to losses and released capacity was performed. Both the losses and the amount of energy served above 50% of line and transformer ratings are low relative to other similar systems elsewhere. The losses are likely a better indicator of optimal locations in this case because the small amount of energy exceeding the 'normal' limits of the lines is very small.
The typical additional benefit of DG on the CPAU system is on the order of 3-5% of either the generator capacity or the kWh generated. This is dependent on how the generation is dispatched. Running the large CHP generators continuously likely negates the additional energy loss benefit by causing additional losses. The PV solar options and the pump regeneration options are not as effective against the system peak as dispatchable generation.
3.2. Description of Analysis

This chapter describes the work performed to gain an understanding of the essential electrical characteristics of the CPAU system and to evaluate the feasibility of proposed DG 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. Determine power flow characteristics. The primary effort is to generate graphics of the power flow, losses, and capacity to rapidly gain an understanding of the system and begin to understand where there might be some opportunities for DG.

Throughout the analysis, loss estimates include all 60 kV and primary distribution line losses. Secondary losses were not estimated.

2. Perform a siting analysis for various sizes of generation to determine where the most benefits to the system can be obtained. Only distribution-connected DG (12 kV or less) was considered in this analysis.

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 15 shows a typical diagram for the peak load case for the CPAU System. The thickness of the lines in this plot is in proportion to the power flowing in the lines. Therefore, the main feeders are clearly visible. This helps the engineer understand how things are connected and how the power is distributed.

This is a simplified model of the system that was reduced to approximately 1200 bus locations. The entire 60 kV system is included in the computer model although only the distribution system is shown on the diagram for clarity. It is important to include the 60 kV system because it is a major contributor to DG benefits in this case.

Each of the substations is marked with a “Δ” symbol and labeled with its 2-letter code.
Figure 15: Power Flow in CPAU Distribution System
Line thickness is proportional to power flow (The 60 kV network is not shown.)

Figure 16: Circuit Plot With Line Section Thickness Proportional To Losses
Figure 16 highlights the line segments that have the highest losses at peak load. This analysis often gives a good 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. The areas highlighted do indeed show up later as some of the more optimal areas for siting DG with respect to losses. The highlighted feeders are the more heavily loaded with respect to the conductor impedances.

3.3.2. Annual Load Characteristics

The next engineering screen is to run a yearly simulation to get an idea of what kinds of DG might have the most benefit. Figure 17 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, normalized to the peak value for the year. This gives a good idea of when generation would have to be available to do the most good.

This is the total load characteristic for the system derived from annual simulations of the individual feeder characteristics. This shows that the system as a whole is generally summer peaking, but the characteristic is relatively flat. The fairly broad peak occurs during the middle of the day. The individual feeders and substations have more varied characteristics. Some feeders are winter peaking. Some feeders peak later in the day. The overall peak suggests that greater benefit to the total system would come from generation that is more capable of addressing the mid-day peak in the summer than at other times. This might favor technologies like solar and CHP generation associated with daytime businesses.
Figure 17: Annual Energy Load Shape

Figure 18: 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 Figure 18. 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. This plot highlights the time of year when the system will likely benefit the most from load reduction made possible by DG. The time period of highest interest would seem to be from 11 AM to 6 PM from mid-May through mid-September.

Finally, a capacity screen is performed. The plots in Figure 19 and Figure 20 were generated by setting the Normal ratings of lines and substation transformers to approximately 50% of their maximum ratings. Then the energy exceeding the Normal rating (referred to as 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 influence the values shown here.

The value determined for the base case here will be used to compare proposed DG 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, our assumption is that the utility can be reasonably assured of finding enough delivery capacity in alternate paths to restore the system in the case of delivery element failures. Engineers normally plan to be able to serve the entire 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 several utilities that have a strong interest in reliability. The 50% level is used here as a benchmark to compare proposed alternatives primarily because the system is not heavily loaded and the normal limit has to be set at a relatively low value simply to gain resolution in the calculation of this number. Unless there is a specific reason, we generally do not set the normal limit below 50% of maximum rating. For the Reliability study the loading level was varied from approximately 150 MW to 195 MW. The two plots shown in Figure 19 and Figure 20 below are the results for the extremes of this simulation.
Figure 19: Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At 150 MW Load Level

Figure 20: Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At 195 MW Load Level
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 DG application. Also, the shape is critical. To have a significant impact on distribution reliability, the proposed DG 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 EEN curve suggests that the CPAU system is at the greatest risk of not being able to cover a contingency with a quick simple load transfer in the middle of the afternoon on summer days. This confirms the loss and power flow results and defines the time of constrained delivery capacity more precisely. 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 should have significantly lower risk. This is the kind of result one might expect from a system with the loading of the CPAU system.

An evening winter constraint also shows up clearly in this analysis. This peak seems likely to be correlated to the Christmas holiday season.

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 DG to a distribution system are very much site specific.

The “optimal” location for DG 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.

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 a reliable 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 often 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 the case of CPAU, the distribution system as a whole is not heavily loaded. Therefore, the loss evaluation tends to dominate the optimal siting analysis. The 60 kW system also has significant influence on the optimal location.
In this study, a 100 kW test generator was used for the small unit size and 2000 kW (2 MW) for the large size. 100 kW is small relative to the capacity of any of the feeders and lateral branches. We generally prefer using a 5 MW generator for the large siting analysis. However, this is too large to be practical for a 4 kV feeder location and a 2 MW size was chosen instead. For a later analysis, a 10 MW test generator was used at the specific request of CPAU to find locations suitable for such large generation.

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. Then the screen is repeated using EEN as the main criterion. It should be noted that the results depend on the specific loading assumptions in the model. CPAU could hypothetically vary the loading relatively easily by changing the switches and rearranging the feeders so that the optimal locations might very well shift to another feeder.

Figure 21 depicts the results of this analysis. The darkest-colored bus locations represent the top 25% with respect to loss reduction. The lightest color represents the lowest 50%.

At the 195 MW loading level, the computed loss improvement varied from essentially 0 to 9.5% of the generator’s capacity (max of 9.5 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 marginal improvement declines for subsequent generators added in the same general area.

Figure 21: Darker colors indicate more optimal locations for small generation (100 kW) on CPAU system with respect to reducing peak load losses.
This graphic indicates that the areas most likely to benefit from small widely dispersed generation are scattered throughout the service area. It should be noted that all locations on the distribution have some benefit with respect to this criterion, if only very modest. The darker areas indicated are those where load reduction would have the greatest benefit to system efficiency with some possible some benefit to capacity.

Figure 22 is a similar plot of the degree to which the test generation releases capacity (reduces EEN) in the lines. The darker 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 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 DG into the highlighted areas, it may be possible to defer investment in new wires capacity for a very long time. Since there is currently sufficient capacity in the CPAU system, this is a potentially attractive approach in areas where the load growth is expected to be low.

The clusters of more favorable areas are in the center of the service territory, and in areas served by the MB, AL, and QR substations. Also, there is a modest benefit to the long feeder from HV extending to the bottom of the figure. The range represented by the color gradations is from -0.8% to 1.8% of DG capacity improvement in EEN at peak load (195 MW loading level). Therefore, there is less relative difference in locations than with the loss evaluation. This is a reflection of the fact that the feeders are not heavily loaded.

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 DG to have any real value for capacity purposes, it must not only be in the right location but be capable of producing power at the proper times.
Figure 22: Darker colors indicate more optimal locations for small DG (100 kW) with respect to releasing distribution capacity.

Figure 23: Darker colors indicate less 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 darker areas in Figure 23 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 24 shows the least helpful with respect to loss reduction for a 100 kW test generator. Note that there is considerable overlap between these areas and the most beneficial with respect to system capacity. While distribution systems generally have a strong correlation between the optimal areas for losses and the optimal areas for capacity reduction, there are common exceptions. This case seems to be an exception to the rule and could be due to the fact that the 60 kV sub-transmission system is included in the analysis. Another contributing factor is that the system is relatively lightly loaded and we are only counting EEN-based capacity relief above 50% line and transformer loadings. While there is considerable difference in locations with respect to losses, there will not be as much difference in released capacity between locations until load increases. Therefore, the loss evaluation is likely to be more useful in this case for differentiating between optimal locations.

Figure 24: Darker colors indicate less optimal locations for small DG (100 kW) with respect to reducing losses.
3.4.2. Large (2,000 kW) Test Generator

The previous analysis was repeated for a large generator (2 MW). This value was chosen because it is approximately 50% of the capacity of a 4 kV feeder. While the 100 kW generator resulted in reduced losses in all distribution system locations, a generator this large would be expected to actually increase the losses in some locations. It may seem contrary to the conventional wisdom that DG reduces losses, 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 7% of the generator size (14 kW) to a 6% (12 kW) increase in losses. Figure 25 shows the optimal locations with respect to losses. Conversely, Figure 26 shows the least optimal locations. In fact, these are locations where the losses will likely be increased by placing such a large generator.

Figure 25: Darker colors indicate more optimal locations for a large DG (2 MW) with respect to loss reduction at peak load.
Figure 26: Darker colors indicate the least optimal locations for large DG (2MW) with respect to losses.

Placing such a large generator in the areas with darker circles could overload the local system.

The optimal locations for a 2 MW generator with respect to capacity are shown in Figure 27, and the less optimal locations with respect to capacity are shown in Figure 28. These areas are similar to that for small generation. As with the small generation, the range of values is not as large (relative to generator size) as for the losses. The EEN reduction ranges from –0.7% to 1.9% of generator capacity.

Since 2 MW is such a large amount, it frees up most 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: Darker colors indicate more optimal locations for a large DG (2 MW) with respect to released capacity.

Figure 28: Darker colors indicate less optimal locations for a large DG (2 MW) with respect to released capacity.
3.5. Comparison of Cases

3.5.1. Base Case (No RDG)

To compare the DG options, we need to first establish the base case. One key figure of merit is the peak loss value. For the base model at 195 MW loading level, we compute the losses in the primary distribution system and the 60 kV system as follows:

Peak Power Losses: 4,802 kW, or 2.46% of total load

Annual Energy Losses: 1.5% for the same model assumptions

This does not include secondary losses and transformer idling (no load) losses. It includes only the losses in the subtransmission system, the substation transformers and in the primary distribution lines.

From the engineering viewpoint, this value is relatively low compared to other 4 and 12 kV systems we have studied and reflects the evaluation that the system is lightly loaded at the assumed loading level. Typical systems are often up in the 4-5% range with peak loss values sometimes exceeding 8%. The lengths of the lines are relatively short due to the positioning of the substations throughout the city. The exception is the long HV-20 feeder running several miles to the south, but this feeder is not heavily loaded, which results in lower than typical losses. Having plenty of capacity generally makes it easier to accommodate a large amount of DG, but also makes it more difficult to realize value in reducing losses and freeing capacity.

The base case will be compared to two reference DG cases and then to six proposed DG applications. The two references cases are designed to yield information about the potential capacity of the CPAU system to accommodate DG. The two reference cases are:

1. 10 MW of generation distributed in 20 500-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 one 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.
3.5.2. **Reference Case 1: 10 MW of Distributed 500-kW Generators**

The purpose of this case is to provide a reference for comparison of proposed DG applications. This case is designed to be one which is nearly optimal for dispatchable generation distributed around the system.

To establish this case, 10 MW of DG were sited in 500 kW increments to achieve maximum loss improvement at peak load. The chosen locations are shown in Figure 29. Each circle represents a 500 kW generator. The resulting losses at the 195 MW loading level were computed to be:

- Peak losses: 4,104 kW
- Savings: 700 kW less than the Base Case (14.5% savings).

The siting algorithm tends to target areas that are more heavily loaded and areas served by longer lines.

![Figure 29: “Optimal” Locations (Yellow Circles) For 10 MW Of DG Sited For Maximum Loss Reduction At Peak Load.](image-url)
At peak load for the 195 MW loading level (peak annual load), the saving in losses equals approximately 7% of generator capacity. On an annual basis the loss reduction is 2% of the total generation at the 150 MW loading level and 3% at the 195 MW loading level. This is a modest value. Generators in more constrained systems can achieve closer to 10%. The reader should keep in mind that the percentage will decline as the amount of DG on the system increases. At low load conditions, the losses could be larger than without any DG, depending on the size and location of the DG.

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 generally achieve some positive loss savings. However, this is not guaranteed for CHP units that run all the time. 10 MW can be too much for light load conditions, which will actually increase the losses in some cases. The Reliability Analysis chapter will address these issues in more detail. Dispatching the generation as either baseload or peaking is considered.

The engineering question to evaluate is now: Can the system accommodate this kind of generation? The two most likely problems accommodating large amounts of DG on radial distribution systems are (1) voltage regulation, and (2) overcurrent protection coordination.

Thus, these two concerns are the subject of the next step of the screening process. In this section, the voltage and overcurrent screens are combined in a separate section following the description of each case.

3.5.3. Reference Case 2: 4 MW of Distributed PV

This reference case simulates the distribution of 4 MW of small generation across the distribution system. This might represent 2000 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 30 overlaid on the power flow graphic.
The purpose of this case is to provide both a reference for a uniformly distributed (as opposed to optimal) reference case and a reference for intermittent renewable cases.

The total peak load loss savings for this case are 66 kW or about 2.4% saving of peak system losses at the 150 MW loading level. This is 1.65% of generator capacity. The annual loss reduction represents 1.8% of the total generation output at the 150 MW loading level and increases to 2.5% at the 195 MW loading level.

One would expect a uniformly distributed source of generation to yield good results for loss reduction because the current is decreased uniformly throughout the system. However, it is not as good as the previous case where the generation was sited explicitly to reduce losses. The more uniform distribution of generation in this case does not address the losses in the longer and more heavily loaded 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. Although some feeders are exceptions, the total system peak in this case appears to be in the summer daytime. Thus, there is the potential for additional benefits from PV solar generation.

3.5.3.1. Voltage Regulation Screen

An interesting analysis to perform with this reference case is to determine how much uniformly dispersed generation like this PV solar case can be accommodated before the voltage change is 5%. This level 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.

Generators were assumed to be at unity power factor for this analysis. This would be typical for any inverter-based DG while interconnected to the utility system. Synchronous machines would also operate near unity while in parallel operation. The typical connection would regulate power and power factor, so the reactive power production would be limited and approximately constant. Voltage regulation by interconnected DG is generally discouraged unless necessary for successful operation. Obviously, the more reactive power generators are allowed to produce, the more the voltage swing when the generation disconnects. We perform this screen assuming that the DG reactive power production is negligible unless we have specific reactive power specifications.

This analysis was done by increasing the generation by a factor until the voltage drop exceeded 5% when it was forced off. This is one indication of the maximum amount of DG that can be accommodated under ideal conditions without expensive changes to the distribution system. The results are shown in Table 13.

<table>
<thead>
<tr>
<th>Total DG</th>
<th>Voltage Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 MW</td>
<td>0.30%</td>
</tr>
<tr>
<td>40 MW</td>
<td>1.46%</td>
</tr>
<tr>
<td>80 MW</td>
<td>3.00%</td>
</tr>
<tr>
<td>120 MW</td>
<td>4.5%</td>
</tr>
</tbody>
</table>

In this case, the results are nearly linear with the amount of generation, which is expected for a uniform distribution in which there are no serious constraints.

Based on this criterion alone, one would estimate that the total amount of uniformly distributed DG that could be accommodated without major changes would be quite a large proportion of the total load – in excess of 120 MW. Keep in mind that this assumes a
widely dispersed amount of generation distributed proportionately to the load. If the DG were concentrated in a specific area, voltage problems are likely to arise at much lower amounts of DG. Each case should be evaluated separately.

On other distribution systems, voltage regulation issues typically arise when total DG capacity is in the range of 10% to 30% of design capacity. If the DG is located closer to the substation, the 5% voltage change will occur toward the upper end of this range. Conversely, if the DG 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 CPAU system is shorter, on average, and/or the system is not as heavily loaded as other distribution systems we have studied. The one notable exception that will appear later in this section is the proposed water pumping regeneration project in which the generation is on the long feeder running to the bottom of the figures.

3.5.3.2 Overcurrent Protection Screen

Solar PV generation is interconnected through inverters. We do not consider inverter-connected DG to be a significant source of fault current. Once currents begin to approach 2 per unit in the inverter, or less, the inverter will typically abruptly cease to energize the system. Therefore, we do not perform fault current contribution calculations.

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.
3.6. Proposed RDG Cases

3.6.1. 570 kW Photovoltaic (PV) Solar At Selected Sites

The locations and sizes of PV solar generation are assumed to be as follows for this case:

- 100 kW at Cubberley Community Center
- 200 kW at the Municipal Service Center
- 100 kW at the Cambridge Parking Garage
- 100 kW at the Municipal Golf Course
- 30 kW at the Baylands Interpretive Center
- 30 kW at the Animal Shelter
- 15 kW at Fire Station #2

The approximate locations are indicated in Figure 31.

Figure 31: Yellow circles indicate approximate generator locations for proposed CPAU PV solar case.
3.6.2. **730 kW Water Pump Regeneration**

The basic concept with this case is that energy required to lift water to the reservoirs can be recovered as the reservoirs are lowered each day as required for water system operation. For this case, the following generation capacities were assumed:

- Dahl 92 kW
- Park 131 kW
- Boronda 214 kW
- Corte Madera 200 kW
- Quarry 100 kW

The generator locations are shown in Figure 32.

![Figure 32: Generator Locations For Water Pump Regenerative Case](image)

In this study, the generators are assumed to operate 4 hours per day from 11 AM to 3 PM.

3.6.3. **2 MW Combined Heat & Power (CHP) Near VA Hospital**

The optimal location based on combination of loss reduction and released capacity criteria for generators in the 2 MW size frequently came out in the vicinity of the VA hospital. Since this was a site of interest to CPAU, this case was set up with a 2 MW generator at
that location shown in Figure 33. This generator is assumed to run continuously in this case.

![Figure 33: Generator Location For Generator Near VA Hospital](image)

Applies to next two cases as well.

### 3.6.4. 2 MW Peaking Generation Near VA Hospital

Instead of running the generation in the previous case continuously, the generation was simulated as peaking generation. Assuming the number of hours of operation might be limited to approximately 150 for environmental emission reasons a dispatch shape of 138 Hr/yr was developed that targeted the more constrained delivery times. The cumulative shape of this dispatch characteristic is shown in Figure 34.

The generator was assumed to be either fully on or completely off. This shape is the integrated value of the total number of hours the generator was dispatched on during that hour of the day in a given month.
3.6.5. 10 MW CHP Generation Near VA Hospital

At the request of CPAU, the VA hospital area was evaluated for a large (10 MW) CHP application. Although the most optimal locations for such a generator seemed to be clustered around the QR substation (see the next case description), sites near the VA hospital were nearly as optimal.

For many sites in the CPAU system, a 10 MW generator is too large to be efficient. The optimal locations for a single 10 MW generator are illustrated if Figure 35 and Figure 36 based solely on loss and released capacity criteria, respectively. The clusters of optimal locations are around the QR, PB, and MB substations. The VA hospital location shows up as one of the top locations (darkest circle) by either criterion.
This case is essentially the same as the 2 MW CHP case above except for the size of the generator.
3.6.6. 10 MW CHP Generation on QR Substation

As seen in Figure 35 and Figure 36 there are clusters of darker-colored dots in the vicinity of the QR substation. In fact, for loss considerations, which are likely more important for a large generator running continuously, these locations consistently came out as the most optimal.

This case was simulated by assuming a continuously-running generator at the Stanford Hospital location as shown in Figure 37.

![Figure 37: Generator Location For 10 MW CHP On QR Substation Case](image)

3.7. Voltage Change Impact Screen

One of the more limiting factors for how much DG can be accommodated without changes to the way the existing system is operated is how much the voltage changes when the generation suddenly connects or disconnects. All DG would have to disconnect at the same time for a few minutes following a major disturbance, such as a momentary interruption on the transmission grid. When the resulting voltage change becomes excessive, changes will have to be made to the distribution system to compensate. Table 14 shows the maximum voltage change for each of the cases described above.
### Table 14: Maximum voltage change for generator on/off

<table>
<thead>
<tr>
<th>Case</th>
<th>Max % Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>570 kW photovoltaic (PV) solar at selected sites</td>
<td>0.1%</td>
</tr>
<tr>
<td>730 kW water pump regeneration</td>
<td>1.72%</td>
</tr>
<tr>
<td>2 MW CHP near VA hospital</td>
<td>0.95%</td>
</tr>
<tr>
<td>2 MW peaker near VA hospital</td>
<td>0.95%</td>
</tr>
<tr>
<td>10 MW CHP near VA hospital</td>
<td>4.5%</td>
</tr>
<tr>
<td>10 MW CHP near QR substation</td>
<td>1.95%</td>
</tr>
<tr>
<td>10 MW Optimal Reference Case 1</td>
<td>2.4%</td>
</tr>
<tr>
<td>4 MW PV Reference Case 2</td>
<td>0.17%</td>
</tr>
</tbody>
</table>

None of these voltage changes exceeds our nominal guidelines of 5%. However, the VA Hospital feeder with the large CHP generator might warrant some attention, especially if larger generation is contemplated. Some fast response voltage regulators might be required. This analysis was done assuming the generators would not be used to help regulate the bus voltage. If the reactive power output of the generator is significant, the voltage change can be larger.

These results suggest that it should be possible to accommodate the other proposed cases with few, or no, changes.

This chart illustrates one of the problems with attempting to define the amount of generation that can be accommodated on a system without significant changes. Based on Reference Case 1, one might say that the no changes limit with respect to voltage on the Palo Alto system is between 20-25 MW. This generation is concentrated in areas where the loading is a higher percentage of capacity rather than being broadly distributed. Above this amount of generation, the voltage change is likely to exceed 5%. If large generation is concentrated in one location, the limit for the 12 kV feeders is likely to be closer to 10 MW. If the generation is uniformly distributed proportionately to load as in the 4 MW PV reference case, a very large amount of generation, perhaps exceeding 120 MW, can be accommodated before the 5% voltage change criterion is exceeded. In this case, one is essentially canceling load. Therefore, this result emphasizes that the amount of generation that can be accommodated without changes to the distribution system is very dependent on the location of the generation. In general, the closer the generation is to the substation, the smaller the voltage change is likely to be for a given amount of generation.

No load tap changer (LTC) operations were assumed for this computation. We are interested here in the voltage change that will occur before the LTC has time to respond.
3.8. Overcurrent Protection Impact Screen

The next concern is the interference of the DG with the overcurrent protection scheme. The basic screen is to compute the amount of increased short circuits resulting from the proposed generation. If the current increase is too large, then further study is warranted.

Table 15 shows the maximum increased current in amperes and the maximum percent increase in fault current for each case considered in this analysis, including the two reference cases. The maxima do not necessarily occur at the same bus. The fault contribution for the two PV solar cases is assumed to be negligible. This assumes the inverters limit the current injection and promptly turn off upon detection of the fault. For the other generation options, an equivalent synchronous machine with a kVA rating 125% larger than the kW output and a net transient reactance of 28% was assumed. Only the contribution to three-phase faults was computed.

The fault contribution analysis assumes rotating machinery with an equivalent impedance of 27% including step-down transformer. That is intended to nominally represent transient reactance, which will vary by machine design. The estimate applies to synchronous machines in all fault conditions and induction machines for SLG faults. Induction machines would be assumed not to contribute significantly to 3-phase faults. This analysis does not apply to technologies that do not contribute significantly to faults. This would include all modern inverter-based technologies that cease switching when currents exceed semiconductor switch limits.

The maximum changes in fault current were determined from a fault study that placed faults at all locations in the circuit and compared the results.

Table 15: Comparative Impacts of The Various DG Options on Overcurrent Protection of CPAU System

<table>
<thead>
<tr>
<th>Case</th>
<th>Increased</th>
<th>Percent of base case fault current</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Current, A</td>
<td>Increase</td>
</tr>
<tr>
<td>4 MW Distributed PV</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>415</td>
<td>7.5</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>415</td>
<td>7.5</td>
</tr>
<tr>
<td>10 MW Optimal Gens</td>
<td>635</td>
<td>29</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>2175</td>
<td>40</td>
</tr>
<tr>
<td>10 MW CHP @ QR Sub</td>
<td>2246</td>
<td>30</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>150</td>
<td>12</td>
</tr>
<tr>
<td>CPAU PV Case</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
The three cases with 10 MW of generation are the most likely to interfere with the overcurrent protection system. They increase some fault currents by 30-40%. This is a modest percentage increase compared to other systems where DG has been known to double the fault current. However, this value of change is sufficient to desensitize relays (reduce the reach) and cause nuisance (sympathetic) tripping of ground fault detection relays. Also, the two 10MW CHP cases take the fault currents on their respective feeders to over 10,000 A. There may be older fused cutouts on these feeders that are only capable of interrupting 8 kA. This would have to be checked and it may be necessary to change some fusing. It would be prudent to perform a detailed coordination study if these options are pursued. The darker shading in Figure 38 and Figure 39 show the areas more likely to be impacted by the increased short circuit current. The other cases change the fault current by such a small percentage that interference with utility relaying is unlikely.

Keep in mind that this estimate is done assuming synchronous machines at the sites. Some of these may be induction machines, in which case the fault contribution will be somewhat less. Induction generators would not feed three-phase faults significantly, but could feed unbalanced faults where there is still sufficient voltage to excite the machines. Single-line-to-ground faults are the most common type of fault and there will be some contribution from the machines (perhaps contrary to popular opinion). A conservative approach is to design for the same-sized synchronous machine.
3.9. Annual Energy Simulation Comparison

Annual simulations of the base case, the six DG options, and two reference cases have been completed. The results of the energy savings analysis are summarized in Table 16 and Table 17.

Table 16: Comparison of Annual Energy Savings for DG Options

<table>
<thead>
<tr>
<th>Case</th>
<th>Gen MW</th>
<th>Purchase Power Savings</th>
<th>Peak Demand Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>MWh</td>
<td>% of Gen</td>
</tr>
<tr>
<td>4 MW Distributed PV</td>
<td>4.00</td>
<td>7368</td>
<td>102.4</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>2.00</td>
<td>292</td>
<td>105.6</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>2.00</td>
<td>18098</td>
<td>103.3</td>
</tr>
<tr>
<td>10 MW Optimal Gens</td>
<td>10.00</td>
<td>90228</td>
<td>103.0</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>10.00</td>
<td>87802</td>
<td>100.2</td>
</tr>
<tr>
<td>10 MW CHP QR Sub</td>
<td>10.00</td>
<td>88244</td>
<td>100.7</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>0.73</td>
<td>1094</td>
<td>102.8</td>
</tr>
<tr>
<td>CPAU PV Case</td>
<td>0.57</td>
<td>1053</td>
<td>101.8</td>
</tr>
</tbody>
</table>
Table 17: Comparison Of Annual and Peak Loss Savings for DG Options

<table>
<thead>
<tr>
<th>Case</th>
<th>Annual Loss Savings kWh</th>
<th>% of total system losses</th>
<th>% of gen kWh</th>
<th>Peak Loss Savings kW</th>
<th>% of peak losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>4 MW Distributed PV</td>
<td>178886.4</td>
<td>1.2</td>
<td>2.5</td>
<td>92</td>
<td>1.9</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>15674.68</td>
<td>0.1</td>
<td>5.7</td>
<td>101</td>
<td>2.1</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>582253.8</td>
<td>3.8</td>
<td>3.3</td>
<td>134</td>
<td>2.8</td>
</tr>
<tr>
<td>10 MW Optimal Gens</td>
<td>2807168</td>
<td>18.6</td>
<td>3.2</td>
<td>699</td>
<td>14.5</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>325375</td>
<td>2.2</td>
<td>0.4</td>
<td>262</td>
<td>5.5</td>
</tr>
<tr>
<td>10 MW CHP QR Sub</td>
<td>666364</td>
<td>4.4</td>
<td>0.8</td>
<td>233</td>
<td>4.8</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>29710.15</td>
<td>0.2</td>
<td>2.8</td>
<td>2</td>
<td>0.0</td>
</tr>
<tr>
<td>CPAU PV Case</td>
<td>19467.12</td>
<td>0.1</td>
<td>1.9</td>
<td>10</td>
<td>0.2</td>
</tr>
</tbody>
</table>

3.10. Observations

The two 10 MW CHP cases, while achieving approximately 3% reduction in demand at peak, net out approximately even for the year in terms of energy. There are savings over the base case at peak load, but as the load drops, the large generator actually results in increases in losses during those time periods. This is illustrated by comparing the 2 MW CHP cases near the VA Hospital to the 10 MW case. Both of the 2 MW cases achieve a 3-5% boost over purchased power reduction for loss reduction. This suggests it might be beneficial to consider an intelligent dispatch system for any large generation in these areas to get optimal benefit. This would have to be considered along with the thermal load demand to achieve optimal performance.

Because the losses are low, the greater benefit of any DG to the CPAU system will be through reduction in purchased energy. As expected, Reference Case 1, which has 10 MW of generators sited for optimal reduction of losses at peak load, has the best performance with respect to losses. The annual losses can be reduced approximately 18% and the peak demand can be reduced almost 6% of the generation capacity.

The pump regeneration case does not achieve any peak demand or loss savings because it is not running at that time. The pumps regenerate for only 4 hours a day and will miss the peak on many days. Annual loss savings are achieved with this case.
4.0 Load and Resource Analysis

An important element of any 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 presents information on CPAU load shapes and the impact of characteristic RDG output shapes on peak load reduction and losses.

4.1 Local Area Load Shapes

E3 collected load shape information from CPAU for each feeder. The data were for the year 2002 - 2003. The CPAU system was simulated using Electrotek’s DSS program which enabled a determination of the system characteristic for the entire year.

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 system load value determined by the simulations is plotted. The result is an image representing the load shape, as shown in Figure 40.

![Figure 40: CPAU System-Wide Annual Load Shape](image)

As seen in Figure 40, CPAU’s peak occurs during mid-day in the summer months. This plot shows the shape for a peak loading of 195 MW, which occurs at 3:00 PM in July.
The data from Figure 40 is shown as a topographical chart in Figure 41 with 20 MW per contour. The topographical chart shows the same information, but is easier to read in terms of the exact peak load timing.

![Topographical Representation Of CPAU System-Wide Load Shape](image)

**Figure 41: Topographical Representation Of CPAU System-Wide Load Shape**

### 4.2. RDG Output Characteristics

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

Both the output pattern and the location within the CPAU system change the renewable generator’s ability to provide peak load relief (based on coincidence with the system profile above) and reduce losses. The following sections summarize the contribution of each of the load shapes to reduction in EEN, peak, and average system losses.

### 4.3. Summaries of Demands and Savings

There were six (6) primary cases investigated in this analysis. Two reference cases were also analyzed to establish benchmarks for comparison purposes. Table 18 through Table 20 show the savings in power demand and losses for each of the DR options considered in
this analysis. These tables were compiled for the loading level corresponding to a 195 MW peak load.

Table 18: Purchased Power and Demand Savings

<table>
<thead>
<tr>
<th>Case</th>
<th>Gen Size</th>
<th>Purchase Power Savings</th>
<th>Peak Demand Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MW</td>
<td>MWh</td>
<td>% of Gen</td>
</tr>
<tr>
<td>10 MW Optimal Gens (Ref 1)</td>
<td>10.00</td>
<td>90228</td>
<td>103.0</td>
</tr>
<tr>
<td>4 MW Distributed PV (Ref 2)</td>
<td>4.00</td>
<td>7368</td>
<td>102.4</td>
</tr>
<tr>
<td>PV Case</td>
<td>0.57</td>
<td>1053</td>
<td>101.8</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>0.73</td>
<td>1094</td>
<td>102.8</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>2.00</td>
<td>18098</td>
<td>103.3</td>
</tr>
<tr>
<td>2 MW Peaker @ VA</td>
<td>2.00</td>
<td>292</td>
<td>105.6</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>10.00</td>
<td>87802</td>
<td>100.2</td>
</tr>
<tr>
<td>10 MW CHP QR Sub</td>
<td>10.00</td>
<td>88244</td>
<td>100.7</td>
</tr>
</tbody>
</table>

Table 19: Annual Loss Savings

<table>
<thead>
<tr>
<th>Case</th>
<th>Gen Size</th>
<th>Annual Loss Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MW</td>
<td>kWh</td>
</tr>
<tr>
<td>10 MW Optimal Gens (Ref 1)</td>
<td>10.00</td>
<td>2807168</td>
</tr>
<tr>
<td>4 MW Distributed PV (Ref 2)</td>
<td>4.00</td>
<td>178886.4</td>
</tr>
<tr>
<td>PV Case</td>
<td>0.57</td>
<td>19467.12</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>0.73</td>
<td>29710.15</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>2.00</td>
<td>582253.8</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>2.00</td>
<td>15674.68</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>10.00</td>
<td>325375</td>
</tr>
</tbody>
</table>
Table 20: Loss Savings at Peak Load

<table>
<thead>
<tr>
<th>Case</th>
<th>Gen Size</th>
<th>Peak Loss Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 MW Optimal Gens (Ref 1)</td>
<td>10.00</td>
<td>666364</td>
</tr>
<tr>
<td>4 MW Distributed PV (Ref 2)</td>
<td>4.00</td>
<td>4.4</td>
</tr>
<tr>
<td>PV Case</td>
<td>0.57</td>
<td>0.8</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>0.73</td>
<td>0.0</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>2.00</td>
<td>2.8</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>2.00</td>
<td>2.1</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>10.00</td>
<td>4.4</td>
</tr>
<tr>
<td>10 MW CHP QR Sub</td>
<td>10.00</td>
<td>0.8</td>
</tr>
</tbody>
</table>

Each of the cases above is described in more detail in the sections that follow.

4.3.1. Reference Case 1: 10 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 DR, 20 combined heat and power (CHP) 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 operating off some sort of renewable fuel. Because the overloading in the normal condition is minimal, the main siting criterion turned out to be loss reduction. The resulting locations are shown in Figure 42.
This generation was simulated as operating continuously as it might in a CHP application. If the CHP generation were to run continuously, the total demand is reduced approximately 10 MW each hour of the day as shown in Figure 43. The actual amount varies with time of day. At peak, the demand is reduced more than 10 MW because the losses are reduced. At minimum load, the reduction is slightly less than 10 MW due to losses in the local lines supplying the generators. This phenomenon is common with relatively large cogeneration that runs continuously on feeders where the load cycles. At times, the generation produces excess current that actually exceeds the load current and results in losses. At peak load, the 10 MW of generation results in a demand reduction of 10.56 MW, with an additional 560 kW coming from the reduction in losses. At minimum load, the losses are increased approximately 100 kW over the base case at the same load. Annually, this generation is quite effective, reducing energy losses by 18%.

This result is not unexpected since the generation was assumed to be sited for optimal loss reduction. However, it does not necessarily imply that it will be economical to run such generators at the off-peak hours just to achieve these loss savings. Even in this favorable case, only 3.2% of the generated energy goes toward loss reduction.
One should keep in mind that the model considers only primary distribution system losses. Primary losses are low in the CPAU system compared to more heavily loaded systems. There is likely an equal, or greater, amount of losses in the secondary distribution system from the distribution transformer through the service drop cable to the meter. Whether the generators will be connected in such a manner to do anything about secondary losses is an open question. Smaller units connected to existing secondary buses may contribute significantly. Larger units may have separate service drops and will suffer the same secondary loss penalty as the loads.

![Figure 43: Impact Of 10 MW Optimally-Sited CHP Generation](image)

Operated as baseload on a typical 7-day load profile during summer peak loading

**4.3.2. Photovoltaic Characteristic**

For this case it was assumed that 2 MW of photovoltaic (PV) generation is distributed approximately uniformly over the system proportionately to load. Assumed locations are shown in Figure 44. A uniform distribution should yield a good estimate of the maximum capacity and loss reduction benefit possible from this type of generation.
For the photovoltaic characteristic, metered output from a nearby photovoltaic installation was assumed. The load shape for the PV output is shown in Figure 45.
Figure 45: PV Output Shape

Figure 45 shows that PV output is consistently good in mid-day hours, even in the winter. January output for the hour from noon to 1:00 p.m., for example, is almost 90% of that in June. The PV output corresponds well with CPAU’s overall load shape, suggesting there might be some value of PV as a deferral mechanism for distribution investment.

Figure 46: Side-by-Side Comparison of CPAU Load Contour and assumed Solar PV Output Contour
Figure 46 shows another view of the correspondence between PV output and CPAU’s load shape. While the correspondence with peak load is good, the duration of the load peak is considerably longer than the solar PV generation can provide without storage. Thus, the capacity provided by PV will be limited.

The impact on peak demand and losses of the PV system is decidedly mixed (refer to Table 1 through Table 3). Nearly 2.5% of the energy generated goes toward reducing annual losses, which is a relatively good number 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 102.4% of the generated energy. Because the PV output aligns with the system load peak, there is nearly a 2% reduction in peak losses.

4.3.3. 570 kW Solar Photovoltaic Case

The assumed locations and sizes of PV solar generation are assumed to be as follows for this case:

- 100 kW at Cubberley Community Center
- 200 kW at the Municipal Service Center
- 100 kW at the Cambridge Parking Garage
- 100 kW at the Municipal Golf Course
- 30 kW at the Baylands Interpretive Center
- 30 kW at the Animal Shelter
- 15 kW at Fire Station #2

The locations are shown in Figure 47.
Figure 47: Yellow Circles Indicate Approximate Generator Locations For Proposed CPAU PV Solar Case
Figure 48: Impact Of 570 Kw Solar PV Case On Total Load For A Peak Summer Week

The 'savings' shown in Figure 48 are basically the solar PV output plus loss savings for each hour. On this scale, the difference between the load shape with and without the generation is barely visible.

4.3.4. 730 kW Water Pump Regeneration

The basic concept with this case is that energy required to lift water to the reservoirs can be recovered as the reservoirs are lowered each day as required for water system operation. For this case, the following generation capacities were assumed:

- Dahl 92 kW
- Park 131 kW
- Boronda 214 kW
- Corte Madera 200 kW
- Quarry 100 kW

The generator locations are shown in Figure 49.
Figure 49: Generator Locations For Water Pump Regenerative Case

Figure 50: Impact Of 730 Kw Water Pump Regeneration Case On Total Load For A Peak Summer Week
As with the preceding PV case, the difference from the base case is barely visible at the leading edge of the peak load in Figure 50. The generation is assumed to produce this power for 4 hours each day as the water levels in the reservoirs are dropped.

4.3.5. 2 MW Combined Heat & Power (CHP) Near VA Hospital

The location of the generator for this case and the next two cases was assumed to be as indicated in Figure 51. This location was found to be near-optimal under a variety of different criteria. The size appears to be well-suited for this area as well. Somewhat larger generators may also bring good value to the system. No attempt has been made to study other generators of similar class, although a much larger generator (10 MW) was considered (see below).

![Figure 51: Generator Location For Generator Near VA Hospital](image)

This generator was assumed to run continuously. The impact of this generator on the system load shown in Figure 52 is to reduce the system demand by a little more than 2 MW due to the reduction in losses. The demand savings are larger by 6% at peak loads as might be expected for this type of generation.
Figure 52: Impact Of 2 MW Of Continuously-Operating CHP Generation Located Near The VA Hospital

4.3.6. 2 MW Peaker Near VA Hospital

The generator location for this case is the same as previous case. However, in this case it was assumed that the generator operates as peaking generation for only the top 138 hours per year. It is assumed that this generation would be limited by either environmental or economic concerns. The dispatch characteristic is shown in Figure 53.

The typical dispatch characteristic resulting from this criterion may be seen for the peak week during the summer in Figure 54. The reduction of the system peak is visible in the chart. The 2000 kW of generation will reduce the peak demand by 2123 kW on the peak loading days.

Such generation is relatively effective against the peak and could be used to help defer system investment. However, like most other peaking generation, it does not operate enough to have much impact on annual load values.
Figure 53: Assumed Annual Dispatch Characteristic For The Peaking Generator

Figure 54: Impact Of 2 MW Of Peaking Generation Located Near The VA Hospital
4.3.7. 10 MW CHP Near VA Hospital

The generator location for this case is the same as previous two cases. This case was analyzed at the request of CPAU to determine the value of larger CHP units to the power distribution system.

The impact of this generation can be seen in Figure 55. At peak load, the generator reduces the demand by 10,282 kW, or 102.8% of generator output. However, the demand reduction is less than 10,000 kW at light load times because the generation is a bit too large for the location assumed. The losses are actually increased at these times over the base case.

On an annual basis, the net energy is computed to be very close to the generator output.

![Figure 55: Impact Of 10 MW Of Continuously-Operating CHP Generation Located Near The VA Hospital](image-url)
4.3.8. 10 MW CHP Near QR Substation

Several locations in the vicinity of the QR substation were identified when seeking an optimal location for a large generator. This case was simulated assuming the generator was at the Stanford hospital site and that it ran continuously.

The impact of this generation on the system is shown in Figure 57. This result is quite similar to the same-sized generator at the VA hospital site except that the annual loss savings are twice as much. This suggests this location is slightly better with respect to losses. However, neither location results in much of a bonus in terms of annual purchased power savings. This suggests that this amount of generation might be on the verge of being too large for a feeder on this system. This conclusion is also consistent with the findings of the Engineering analysis that suggested that modifications to the fault protection system would likely be required to accommodate this much generation (unless it was a technology that did not contribute significantly to faults).
4.4. Conclusions

The typical bonus, if any, from DR that can be expected on this system is in the 2-3% range. If the generator can produce power through the entire system peak, the peak demand can be reduced by an additional 5-6% over the generator output.

Of the cases considered, the 2 MW CHP near the VA hospital would appear to give the greatest benefit for the size of the generator. The two 10 MW CHP cases considered come out about even on an annual basis because they actually increase the losses at minimum load. They achieve a 2-4% reduction in annual losses. If one were able to take the same generation and distribute it optimally over the system, primary distribution and subtransmission losses might be reduced as much as 18% (see Reference Case 1).

The least effective case considered is the water pump regeneration case. Because it is assumed that it can generate only 4 hours per day, it is ineffective against the system peak. It is able to recover some of the energy used to pump the water and 2.8% of the total kWh output goes toward loss reduction, which is in line with the other cases considered.

The PV case is moderately effective against the system peak. It catches the maximum peak, but the PV output shape is not broad enough to catch the evening peak. The proposed PV case is nearly as effective in terms of percent demand and loss reduction as the ideal PV case (Reference Case 2).
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 DR. Some highly constrained systems exhibit gains of 15%, or more, at peak load when the first increment of DR is added. The maximum possible here would appear to be about 5-6% at peak, with an average 2-3% 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) on the reliability of the City of Palo Alto Utilities (CPAU) electrical distribution system. A particular emphasis was given to renewable technologies.

The existing CPAU system has ample capacity for the present peak load of less than 200 MW. The system is relatively compact, consisting of several short feeders. Therefore, capacity issues are not as great as they might be in a more heavily loaded distribution system.

There are several generation proposal considered: There were six (6) basic DG cases proposed:

1. 570 kW photovoltaic (PV) solar at selected sites
2. 730 kW water pump regeneration
3. 2 MW combined heat & power (CHP) near VA hospital
4. 2 MW peaker near VA hospital
5. 10 MW CHP near VA hospital
6. 10 MW CHP near QR substation

These were compared to two reference cases that represent what might be possible with two different DG technologies:

Reference Case 1: 10 MW CHP optimally sited in 20 units of 500 kW each.

Reference Case 2: 4 MW PV solar distributed throughout the system.

Solar PV matches the system peak loading relatively well, although the load peak extends a few hours past when solar power is available without storage. The PV case proposed by CPAU is well position in terms of released system capacity, although it will have little impact on the system losses.

The water pump regeneration proposal has little additional benefit with respect to the power delivery system mainly due to the fact that the pump load is concentrated on one feeder. The benefit from this application would be the recovery of energy required to pump the water into the reservoirs.

The 2 MW CHP application at or near the VA hospital appears to provide the most bang for the buck in terms of benefits to the power delivery system. Measured in terms of either energy exceeding normal or annual losses, this application provides essentially 4 MW of capacity. Operating the same generator strictly as a peaker for the top 138 hours of the year provides minimal capacity and loss relief. The justification for such a DG application would have to come from reduced purchased power and other benefits.
Both 10 MW CHP options run the risk of overloading feeders and increasing losses. This is likely as large of a generator as should be considered for a 12 kV feeder. The option where the generation is placed near the QR substation yields more loss reduction but capacity relief is not as needed. The option near the VA hospital provides slightly less loss reduction, but yields more capacity relief.

At present load levels less than 200 MW, there is not much need for capacity relief from DG. The need will accelerate rapidly should the loading exceed 220 MW.

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

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

DG can increase the capacity of the system and there is an intrinsic relationship between capacity and reliability. To evaluate reliability impacts of DG, we compute the additional load serving capacity made possible by the addition of DG. Where the capacity of the power delivery system has been increased, there is the possibility of better accommodating emergency conditions. We evaluate the impact of a proposed DG application on the capacity of a distribution system by developing a 'cost' function proportional to selected operating quantities. In this case, the quantities are the annual energy losses and the energy exceeding engineering limits as the load grows over a planning horizon.
This process gives a better idea of the impact of smaller incremental capacity additions and, therefore, more easily permits comparisons of DG alternatives. In this particular study, we analyzed the main proposed case and compared it to two reference cases that have more predictable characteristics.

5.2.1. Basic Concept

Figure 58 illustrates the basic concept used in the evaluation of capacity with respect to engineering limits. Two limits are defined: Normal and Emergency (or Maximum). The Emergency limits are never to be exceeded and assume loads would have to be disconnected (load shedding) to avoid damage to the power delivery system. This results in unserved energy (UE). The Normal limit is used for planning studies of the normal circuit configuration, and we call the energy served above this limit EEN, for Energy Exceeding Normal.

The figure illustrates the principle involved using two daily load shapes. One exceeds the Normal limit while the other exceeds the Emergency limit after some assumed growth in the load or alternate configuration of the system. In general, the normal system configuration is used in studies that evaluate EEN and one or more contingency configurations are used in studies concerned with UE.

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

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

The basic method for interpreting the results is illustrated in Figure 58.
Figure 58: Basic Concept Of Unserved Energy (UE) And Energy Exceeding Normal (EEN)

Figure 59: Evaluating The Impact Of DG On The Power Delivery System Capacity

Figure 59 shows the UE curves computed for two cases: the base or "normal" case, and a case with 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 DG option increases to the same value as the base case approximately two years later. Therefore, we can conclude that the DG option can be expected to provide the technical capability for two year’s deferral of the upgrade at the same risk of UE. If the savings in UE and deferral are economic compared to the cost of operating the generator, then the DG option would be a good alternative to new feeder and substation construction. This is a very useful analysis for situations where:

1. It appears that load growth 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 DG adds to the system. This is becoming a popular measure of the effectiveness of all types if DG and is the method chosen to compare alternatives in this analysis. In terms specific to this analysis:

Given a particular DG proposal, how much more load can be served by CPAU 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 regarding impact of DG on distribution system reliability boils down to:

How much more load can be served on the system with x MW of generation?

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

If we define the system as consisting of more than one feeder, the net gain is often much less than the DG size even if it is in a good location for one feeder. A specific generator provides capacity to only one of those feeders and to the substation. However, if the DG is sited so that it unloads a feeder, then it is theoretically possible to transfer loads from another feeder - if tie switches are placed properly - and achieve an apparent capacity increase. The concept is illustrated in Figure 60. 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 has met 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 to 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 used. That is, any time the loading in the Normal configuration exceeds 50% of the feeder capacity, it will be assumed that the reliability of the system is compromised. The amount of energy served above this level (EEN) will be considered the energy at risk. Not only is the CPAU 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. Case Evaluation

For each of the cases described in the following, the total load on the CPAU system is assumed to grow from approximately 150 MW to a little more than 230 MW.

The simulations are performed for the base case with no DG, two reference cases, and six proposed cases. The reference cases are designed to have certain expected characteristics. These provide additional insight into the planning problem by showing what might be achievable by nearly ideal applications of DG with respect to selected criteria.

EEN and loss curves are developed for the various options. To compute EEN values for each case, the Normal rating of the power delivery elements was set to 50% of the maximum, or Emergency, rating as described in the preceding sections. The annual simulation is then performed in the normal circuit configuration and the EEN and losses are tabulated as the simulation progresses. This avoids having to search for critical contingencies and simulating each separately. The reliability evaluation values are computed in one pass. These are then compared to determine the effective additional capacity added by each option compared to the Base Case for the same criteria.

5.4.1. Base Case

![Figure 61: Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At 150 MW Load Level](image-url)
Figure 62: Shape Of Energy Exceeding Normal (EEN) Line And Transformer Ratings At 195 MW Load Level

Figure 61 and Figure 62 show 3-D plots of the annual shape of the EEN for the base case for two different loading levels, 150 MW and 195 MW. At the lower loading level, the assumed Normal rating is exceeded only briefly throughout the year. The results show the summer peak and a winter peak yielding approximately the same amount of EEN. As the loading increases the summer constraints are clearly more dominant. These plots indicate that the system is most constrained in the summer months during mid day. There are also some periods of early evening peaks in the winter months, but the power delivery constraints are more sensitive to the summer peak.

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

5.4.2. Reference Case 1 (10 MW of 500-kW CHP Generators)
The purpose of this case is to provide a reference for comparing proposed DG applications against the base case. This case is designed to be one which is nearly optimal for dispatchable generation distributed around the system. It is called
'CHP' here to succinctly indicate one application for a type of generation that runs continuously. To establish this case, 10 MW of DG were sited in 500 kW increments to achieve maximum loss improvement at peak load. The siting algorithm tends to target areas that are more heavily loaded and areas served by longer lines. It generally results in a DG distribution that has good characteristics for both capacity relief as well as loss reduction, although it would be expected to have better performance with respect to losses. The areas in which the DG units are sited would generally be good areas to target for DG applications. The details of this case are described in the engineering analysis.

Figure 63: EEN Computed For 10 MW Of Baseload

(CHP) generation sited in 500 kW units for maximum benefit to distribution system losses

Figure 63 shows the EEN curve for this case compared to the same curve for the base case. The incremental capacity curve is the distance between the two curves along the horizontal axis. At the low end of the scale, there is insufficient resolution to accurately compute this difference. As the load grows from 170 MW to 230 MW the effective incremental capacity by this measure grows from 4 MW to 11 MW. That is, at 230 MW, adding the DG allows the system load to grow by 11 MW with approximately the same risk of unserved energy as in the base case.

This characteristic suggests that most of the DG is not needed for distribution capacity purposes until the load grows past 200 MW. On most power delivery systems, the incremental capacity curve will rise to a peak and then decline at higher loading as constraints in parts of the system not addressed by this particular DG application begin to dominate the EEN computation.
Figure 64 shows the same comparison with respect to the annual losses. This comparison suggests an incremental capacity of more than twice the DG rated output. Such a good result is not unexpected since the DG unit locations have been selected for optimal benefits with respect to loss reduction.

Two other charts used to judge the effectiveness of a proposed DG application are shown in Figure 65 and Figure 66. Figure 65 shows the annual shape of the peak hourly MW savings in EEN achieved by this generator configuration. This is the peak value of the savings that occurred at a given hour on any day of a given month. The savings are depicted as the 'dent' the generation takes out of the system base EEN characteristic. Thus, the savings show up as negative on this scale.

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 the summer, the generation contributes nearly the full 10 MW to capacity release. This is confirmation that the hypothetical generation is distributed in a manner that is potentially beneficial to the capacity of the system. The peak contribution to capacity occurs briefly in the summer. At other times, less DG contribution is required according to the assumed criteria.

Figure 66 shows the same type of plot for the total (integrated) EEN savings for each hour of the each month. This gives a different picture than Figure 65.
more constrained periods in the winter show up accentuated. This suggests there are more days in the winter where the generation would provide benefit although the maximum benefit in each hour is less than in the summer.

Figure 65: Depiction Of The Impact Of The Generation In Reference Case 1 On The Peak Hourly EEN As Compared To The Base Case
5.4.3. Reference Case 2 (4 MW PV Generation)

In this case, 4 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.

This case might represent the result of an ambitious, long term solar power incentive program that achieved 2000 2 kW residential solar PV units, for example.

Figure 67 shows the EEN computed for this case compared to the base case and the corresponding incremental capacity curve. Figure 68 shows the same type of plot comparing the losses for the two cases.
Both methods of comparing the cases yield very similar effective incremental capacity values: 1.25 and 1.5 MW. By being uniformly distributed proportionately to load over the system, this case is fairly effective for solar PV cases. While the generation briefly provides full capacity relief of 4 MW during one period of the summer as shown in Figure 69, it does not contribute any power to counter evening peaks in the winter and losses at other times.
Figure 68: Capacity Increase With Respect To Losses For 4 MW Of Solar Photovoltaic Generation Uniformly Distributed Throughout The System (Reference Case 2)

Figure 69 and Figure 70 show the peak EEN and total EEN savings, respectively, for this generation. The peak capacity relief is achieved in the middle part of the summer and is skewed toward the early afternoon hours.

Figure 71 depicts the coincidence of the load and solar PV generation for a typical week in the summer. The load shape shown is the computed shape for the entire CPAU system. Certain summer peaking feeders will benefit more from this type of generation than feeders that are winter peaking. This coincidence is relatively good, although the load peak clearly lasts longer than the generation peak. Thus, as expected, the solar PV generation is not proportionately as effective as a well-sited dispatchable generator.
Figure 69: Depiction Of The Impact Of The Generation In Reference Case 2 (4 MW Solar PV) On The Peak Hourly EEN As Compared To The Base Case

Figure 70: Depiction Of The Impact Of The Generation In Reference Case 2 (4 MW Solar PV) On The Total EEN As Compared To The Base Case
Figure 71: Comparison Of CPAU Load Shape And Assumed Output Of Solar PV Generation For A Typical Summer Week

The color contour plots in Figure 72 show another way to view the degree to which the solar PV output matches the Palo Alto load. Here, the red color 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 part of the year. The peak load demand has reasonably good coincidence with the peak solar PV generation, although the peak load period clearly has a longer duration than the solar PV has the ability to supply power without supplementing with energy storage.

By covering some of the peak load during the summer, the solar PV option earns some credit toward improving the reliability of the distribution system. However, the amount is limited due to the nature of the generation and the needs of the CPAU system. For much of the year, the generation is not needed to support the system according to the rating assumptions in this simulation. Something else would have to be done to maintain the capacity of the system at times when the sun is not available as a source of energy. Nevertheless, an effective capacity of nearly 30% of the rating is good for solar PV generation and suggests that the CPAU system might be a good match for this kind of generation.

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 could be less if not applied on parts of the system with a compatible load characteristic.

5.5. Proposed DG Cases

5.5.1. 570 kW Photovoltaic (PV) Solar At Selected Sites

The assumed locations and sizes of PV solar generation are assumed to be as follows for this case:

- 100 kW at Cubberley Community Center
- 200 kW at the Municipal Service Center
- 100 kW at the Cambridge Parking Garage
- 100 kW at the Municipal Golf Course
- 30 kW at the Baylands Interpretive Center
- 30 kW at the Animal Shelter
- 15 kW at Fire Station #2

Figure 73 shows the incremental capacity analysis based on the released capacity in terms of EEN. This shows a quite interesting result. The incremental capacity value is quite sensitive to loading. At lower load levels, there is less need for released capacity. As loading increases to approximately 200 MW, the effective capacity by this measure peaks at approximately the full value of the generation. This is remarkable for solar PV generation. The likely reason is that the PV is sited
on feeders where there is a good match to the load characteristics and there is a need for capacity release. As the load grows beyond 200 MW, the effective value diminishes. This is common for this analysis and indicates that other areas of the system that are not helped by this DG plan are in need of capacity release and they begin to dominate the EEN calculations at the higher loadings.

![Capacity Gain for Proposed CPAU 570 kW PV Generation Case](image)

**Figure 73: Capacity Comparison Based On EEN Of Proposed CPAU Solar PV Case With The Base Case**

Figure 74 shows the incremental capacity analysis based on primary system loss reduction. This indicates an effective value of only approximately 150 kW. The conclusion is that while the proposed PV generation is in a good location to assist with system capacity issues, it is located less well with respect to losses. This pattern is seen when generation is relatively close to the substation or there are losses on lateral branches that the generation can do nothing about.
5.5.2. 730 kW Water Pump Regeneration

The basic concept with this case is that energy required to lift water to the reservoirs can be recovered as the reservoirs are lowered each day as required for water system operation. For this case, the following generation capacities were assumed:

- Dahl: 92 kW
- Park: 131 kW
- Boronda: 214 kW
- Corte Madera: 200 kW
- Quarry: 100 kW

The assumed dispatch characteristic for this case is shown in Figure 75. The pumps are assumed to act as generators for 4 hours a day and that the dispatch can be controlled to align with the early part of the system load peak from about 11:00 AM to 3:00 PM.

Because the pumps are on the same feeder, there is little effective capacity release unless that feeder load was to grow as shown in Figure 76. Even at the higher end of the loadings studied the incremental capacity is minor in terms of released capacity.
In terms of loss reduction, the effect is nearly constant over the range of loading studied. The assumed 730 kW of generation yields an effective capacity of 200 kW as seen in Figure 77.

Figure 75: Assumed Dispatch Characteristic For Regenerative Pump Case
Capacity Gain for
Proposed CPAU 730 kW Regenerative Pumping Case

Figure 76: Capacity Comparison, Based On EEN, Of Proposed CPAU Regenerative Pumping Case With The Base Case

Primary System Losses for
Proposed CPAU 730 kW Regenerative Pumping Case

Figure 77: Capacity Comparison, Based On Losses, Of Proposed CPAU Regenerative Pumping Case With The Base Case
5.5.3.  2 MW Combined Heat & Power (CHP) Near VA Hospital

The optimal locations based on combinations of loss reduction and released capacity criteria for generators in the 2 MW size frequently were in the vicinity of the VA hospital. Since this was a site of interest to CPAU, this case assumes that there is a 2 MW generation at that location. This generation is assumed to run continuously in this case.

Both means of measuring the incremental capacity, EEN and losses, yield similar results: the system load can grow by approximately 4 MW over the entire range studied after the generation is added as seen in Figure 78 and Figure 79. This is twice the size of the generator capacity.

This is an example of hitting the 'sweet spot' on a distribution system in terms of generator size and location. A factor of two is somewhat high for the typical radial distribution feeder. A maximum factor on the order of 1.4 might be more common. However, in this case, the sub-transmission system is included in the model and contributes benefits of loss reduction and released capacity.

This generator is in a good location relative to system needs and is not so large that it overwhelms the local distribution feeder. There is a limit to how much generation can be placed in a given feeder segment and still achieve benefits by this measure. Later, we show the case with 10 MW in the same location, which yields somewhat different results.

![Capacity Gain for 2 MW CHP Near VA Hospital](image)

**Figure 78:** Capacity Comparison, Based On EEN, Of 2 MW Of CHP Generation Near The VA Hospital With The Base Case
5.5.4. 2 MW Peaking Generation Near VA Hospital

Instead of running the generation in the previous case continuously, the generation was simulated as peaking generation. Assuming the number of hours of operation might be limited to approximately 150 for environmental emission reasons a dispatch shape of 138 Hr/yr was developed that targeted the more constrained delivery times. The cumulative shape of this dispatch characteristic is shown in Figure 80. The generator was assumed to be either fully on or off. This shape is the integrated value of the total number of hours the generator was dispatched during that hour of the day in a given month.
The EEN and loss comparisons to the base case are shown in Figure 81 and Figure 82.

These results require some interpretation. Obviously, a peaking generator is designed to be dispatched as needed. Regarding the EEN, if the generator can be dispatched at any given time, the effect on reliability is effectively the same as the generator running continuously, as in the previous case. Therefore, the incremental capacity with respect to EEN would be 4 MW. If the generator is restricted to operating only at the times simulated (the peak 138 hrs), the effective value is considerably less as shown in Figure 81. The incremental capacity is less than half of the capacity of the generator.

In terms of loss reduction, the generator does not operate enough hours to have a significant impact. The annual losses become the same as the base case once the system load has grown a mere 100 kW, or 5% of the generator’s capacity.
Figure 81: Capacity Comparison, Based On EEN, Of 2 MW Of Peaking Generation Located Near The VA Hospital With The Base Case

Figure 82: Capacity Comparison, Based On Losses, Of 2 MW Of Peaking Generation Located Near The VA Hospital With The Base Case
5.5.5. **10 MW CHP Generation Near VA Hospital**

The VA hospital area was also evaluated for a large (10 MW) CHP application. Although the most optimal locations for such a generator seemed to be clustered around the QR substation for this size of generation (see the next case description), sites near the VA hospital were nearly as optimal.

For many sites in the CPAU system, a 10 MW generator is too large to be efficient with respect to distribution losses. That is nearly the case here. There is some positive benefit at lower loading levels, but it would seem that the greater benefit will come as the load grows considerably. The incremental capacity by the measures used here are on the order of 3-6 MW as shown in Figure 83. This is on the order of half the capacity of the generator, which is much different than double the capacity of the generator realized for the 2 MW generator in the same location.

At the lower end of the modeled loading range, this size generator actually increases the annual losses in power delivery elements compared to the base case as shown in Figure 84. This is not unusual with large CHP applications on distribution systems and is not necessarily an indication that the application is inappropriate. Value in other aspects of operation such as demand reduction and energy efficiency at the point of utilization may be more significant. It simply means that no credit should be given for loss reduction until the system loading were to grow to the point that reduction is achievable.

![Capacity Gain for 10 MW CHP near VA Hospital](image)

**Figure 83:** Capacity Comparison, Based On EEN, Of 10 MW Of Peaking Generation Located Near The VA Hospital With The Base Case
5.5.6. 10 MW CHP Generation on QR Substation

For a 10 MW generator, locations nearer the QR substation consistently came out as the more optimal. This case was simulated by assuming a continuously-running 10 MW generator at the Stanford Hospital location.

Upon observing these results, it becomes obvious that the 'optimal' judgment is based much more on loss reduction than on released capacity, although both were considered. As shown in Figure 85, the incremental capacity based on EEN is trivial compared to the size of the generation. However, the generator will allow the system load to grow by 4-6 MW before the losses become the same as the base case, which is marginally better than the previous case where the generator was assumed to be on the other side of the CPAU system.

This result indicates that there is less need for a generator in this location to provide capacity relief, but that the generator might be effective in improving the efficiency of the power delivery system, especially as the load grows in the future.

Figure 84: Capacity Comparison, Based On EEN, Of 10 MW Of Peaking Generation Located Near The VA Hospital With The Base Case
Figure 85: Capacity Comparison, Based On EEN, Of 10 MW Of CHP Generation Located Near The QR Substation With The Base Case

Figure 86: Capacity Comparison, Based On Losses, Of 10 MW Of CHP Generation Located Near The QR Substation With The Base Case
Comparison Summary for All DG Cases

Figure 87 and Figure 88 show the composite of the annual simulation results for all the cases considered in this analysis. Figure 87 shows the comparison of the EEN (labeled 'Overload kWh Normal,' which is the name of the energy meter register in the DSS used for this computation). Figure 88 shows the comparison of the losses. These charts give some additional perspective on these cases.

What one hopes to gain from a good DG application is significant separation of the DG case from the base case. One notable trend from Figure 87 is that the greater benefit to the capacity of the system from DG will likely come later as the load grows above 220 MW. This suggests that the system at present loading levels below 200 MW is relatively lightly loaded and does not need as much capacity relief as it would if the load were 200-230 MW.

In terms of EEN in the power delivery system, the DG options with 2 MW and 10 MW CHP installed near the VA hospital also have relatively good performance compared to other options, especially at the higher loading levels.

The bottom curve in each plot would nominally represent the case with the best impact on the power delivery system. This is the case labeled '10 MW Optimal' which is Reference case 1. It should be no surprise that if we could place 10 MW of
DG in good locations and dispatch it as needed, it would yield good results. This is particularly true of the losses since the DG was assumed to be sited for optimal reduction of losses. The other cases have modest percentage improvements in the losses.

![Figure 88: Comparison Of Annual Losses Versus MW Load For All Cases](image)

5.6. Valuing EEN and Losses

This section provides only the fundamental data for the economic analysis, which is described below. 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 sub-transmission system and primary distribution system for the 180 MW loading level appear to be approximately 10,000 MWh. If the average cost of energy is $30/MWh, the annual cost is 10,000 x 30 = $300,000. The optimal 10 MW DG case saves 2,000 MWh or $60,000 per year at this level.

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 power delivery 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
hours then the EUE might be estimated by multiplying the EEN by 1.5/8760. At a
200 MW loading level, the annual EEN is computed to be approximately 5,000
MWh. Thus, the EUE might be estimated to be 5,000 x 1.5/8760 =0.856 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 from approximately $3,400 to $8,600 per year at the
200 MW loading level.

Compared to other costs involved in applying DG to the CPAU system, this is not
a large cost. This suggests that reliability costs will not be deciding factor in the
overall economics of any of the proposed DG options.

5.7. Economic Evaluation of Reliability Impacts

In the reliability analysis, we investigate the economic value of renewable distributed
generation (RDG) impacts on the electric reliability of the CPAU 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 CPAU
distribution system. We do not consider generation or bulk transmission impacts because
RDG of the size considered in this study would have little impact on those systems.

The goals of planning T&D systems are to

1. provide grid connection service to all customers, based on the utility’s obligation-
to-serve mandate;

2. provide electricity within the power quality standards established by the utility
regulators;

3. assure that there is sufficient capacity or load transfer capability to meet peak
demand; 4) minimize the extent and duration of outages; and

4. 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. 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 using the following formula:

\[ VRI = \Delta EEN \times p(\text{outage}) \times \text{VOS} \]

where: VRI is the value of the reliability improvement; \( \Delta EEN \) is the change in
energy exceeding normal due to the installation of the DG; \( p(\text{outage}) \) is the
probability of having an outage, absent the DG; 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:

\[ VRI_c = \Delta UE_c \times p(\text{outage}_c) \times \text{VOS} \]

where: Subscript \( c \) corresponds to the specific contingency scenario, and \( \Delta UE \) is the
change in unserved energy for that contingency scenario.

Contingency scenarios were not simulated for CPAU.

Unlike other cost elements considered in this study, there is no market for VRI\(^5\). 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

\(^5\) 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.
amount a customer would be willing to pay for their electric service. It is difficult to judge customer willingness to pay, however, so the value is often approximated by the opportunity cost of electric power, which equals the value of unsupplied electricity.\(^6\) VOS reliability therefore becomes synonymous with customer outage costs.

![Customer Value of Service, $/kWh Unserved](image)

**Figure 89: Typical Range Of Reported Values For Customer Value Of Service (VOS)**

The range shown in Figure 89 is due to survey methods used, the types of outages considered, and the specific residents or industries involved. Moreover, customer valuation of outage costs can vary depending upon customers’ experience with outages, and depending upon whether the survey aims to determine their 'willingness to pay' or their 'willingness to accept.' As 'willingness to accept' asks how much the customer should be compensated for lower reliability, the customers provide values here that are always significantly higher than their response to the willingness to pay question. The analyst should take care to assure that VOS values are for willingness to pay and to the extent possible, reflect the attributes of the outages that would likely be avoided by the RDG installation.

Typical mid-range VOS values are listed in Table 21.

---

Table 21: Mid-range customer value of service (VOS) estimates

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>$ per 1 hour</th>
<th>$ per 4 hour</th>
<th>$ per kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential[1]</td>
<td>$4-5</td>
<td>$15-20</td>
<td>$4-5</td>
</tr>
<tr>
<td>Commercial[2]</td>
<td>$400-600</td>
<td>$1,000</td>
<td>$30-50</td>
</tr>
<tr>
<td>Industrial</td>
<td>$10,000-20,000</td>
<td>$40,000-50,000</td>
<td>$10-20</td>
</tr>
<tr>
<td>Agricultural</td>
<td>$100 (summer)</td>
<td>$400 (summer)</td>
<td>$5-10</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$2,500 (winter)</td>
<td></td>
</tr>
</tbody>
</table>

(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 CPAU are shown in Table 22 below. The table shows the impact of an equipment failure that occurs randomly within the year and lasts for 24 hours. The $\Delta$ Overload kWh column shows the reduction in annual Overload kWh Normal as a result of the RDG installation. Given the Overload kWh Normal under the "no DG" case, this 1 day out of 365 translates to less than one outage hour per year. The probability of an outage ($p(\text{outage})$) and the VOS value of $8/kWh are representative of a mixed use area with residential, commercial, and light industrial customers in California.

---

7 EEN = 54,847, Total kWh Consumption in the year = 783,417,065, so the percentage of annual consumption that would go unserved from a failure that lasts the entire year is $\frac{54,847}{783,417,065} = \text{less than 0.01\%}$. Combining this value with the likelihood of an equipment failure gives the likely percentage of energy unserved (assuming the probabilities are independent) = 0.01\% * 1/365 = 0.000002\%. Assuming a 60\% system load factor, this translates to about less than one hour (.001 hour) per year of outage on average for CPAU customers (.00002\% * 8760 / 60\%).
Table 22: Value of Reliability Improvement (Year 2004)

<table>
<thead>
<tr>
<th>Case</th>
<th>&quot;Overload kWh Normal&quot;</th>
<th>Δ &quot;Overload kWh Normal&quot;</th>
<th>p (outage)</th>
<th>VOS ($/kWh)</th>
<th>VRI</th>
</tr>
</thead>
<tbody>
<tr>
<td>No DG</td>
<td>54,847</td>
<td>NA</td>
<td>0.27%</td>
<td>$8</td>
<td>NA</td>
</tr>
<tr>
<td>4 MW Distributed PV</td>
<td>40,093</td>
<td>14,754</td>
<td>0.27%</td>
<td>$8</td>
<td>$319</td>
</tr>
<tr>
<td>2 MW CHP Peaker @ VA</td>
<td>27,821</td>
<td>27,026</td>
<td>0.27%</td>
<td>$8</td>
<td>$584</td>
</tr>
<tr>
<td>2 MW CHP Baseload @ VA</td>
<td>25,401</td>
<td>29,446</td>
<td>0.27%</td>
<td>$8</td>
<td>$636</td>
</tr>
<tr>
<td>10 MW Optimal Gens</td>
<td>17,295</td>
<td>37,552</td>
<td>0.27%</td>
<td>$8</td>
<td>$811</td>
</tr>
<tr>
<td>10 MW CHP @ VA Hosp</td>
<td>24,909</td>
<td>29,938</td>
<td>0.27%</td>
<td>$8</td>
<td>$647</td>
</tr>
<tr>
<td>10 MW CHP QR Sub</td>
<td>53,359</td>
<td>1,488</td>
<td>0.27%</td>
<td>$8</td>
<td>$32</td>
</tr>
<tr>
<td>Pump Regen Case</td>
<td>54,775</td>
<td>72</td>
<td>0.27%</td>
<td>$8</td>
<td>$2</td>
</tr>
<tr>
<td>CPAU PV Case</td>
<td>53,838</td>
<td>1,008</td>
<td>0.27%</td>
<td>$8</td>
<td>$22</td>
</tr>
</tbody>
</table>

Total usage is 783,417,065 per year, so the annual Overload kWh Normal in the “no DG” case represents less than 1% of the total annual usage. This represents an extremely small risk of outages related to loading levels. Of particular note is the low VRI offered by the 10 MW CHP at the QR substation when compared to the 10 MW of optimally-sited generation units. This twenty-fivefold difference in value highlights the importance of conducting the engineering and reliability analysis as part of a comprehensive RDG analysis.

5.8.1.1. VRI Benefit Feedback Loop

The VRI benefit described above may be factored into the benefit/cost analysis of each DG option. We allow this to occur through a ‘switch’ in the ‘feedback’ tab of our screening model. If set to ‘true’ the VRI values are factored into the benefit/cost analysis; if set to ‘false’ they are not. This feedback loop is represented by the dashed line in Figure 90.
5.8.2. Deferral Benefit of DG

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

Figure 91 shows how deferral length could have been derived from the CPAU EEN curves. Imagine that a level of 5,000 MWh of EEN was determined to be the acceptable level, and the utility would invest in new distribution if EEN was expected to exceed this level. Under the base case, this level of EEN would occur at a system load of approximately 200 MW. But with the 10 MW of optimally-sited RDG, this level of EEN does not occur until system load has reached almost 210 MW. The 10 MW capacity gain can be compared to projected load growth to determine the number of years the distribution upgrade could be deferred without increasing EEN over the base case.
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 92 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].
For CPAU, 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 by developing measures of the potential cost to customers of changes in expected reliability. The Relative Customer VRI method starts with the calculation of the value of reliability improvement due to the installation of DG.
\[ VRI_t = \sum_c \Delta EUE_t \cdot Class\%_{c,t} \cdot VOS_c \]

where:  
\( \Delta EUE \) is the change in EUE due to the implementation of DG  
Class\% is the percentage of peak usage for each customer class  
VOS is the customer value of service  
c is the customer class  
t is the year  

\( \Delta EUE \) 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?' The issue of cost test perspectives is covered in detail in the economic screening analysis.

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 numbers focus on the direct impact on individual customers and fail to recognize the larger effects that degraded reliability can have on a local community. For example, low reliability could force businesses to leave the area, resulting in a ripple effect through the community from fewer jobs, less 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
The RDG Assessment project results described in the economic screening chapter are driven by Base Case input data. The resulting conclusions are subject to uncertainty given variability in input assumptions used throughout the analysis. E3 developed uncertainty analysis to test how alternate scenarios for several key input data would affect the overall results of the assessment. This chapter describes the method we used to test the sensitivity of the RDG Assessment results to particular ranges of uncertainty in the inputs. We built this testing process into the RDG screening tool so that users can easily observe the potential robustness of their results under uncertainty and subsequently improve their information for decision-making and planning.

6.1. Scenario Analysis for Key Inputs
We established automated sensitivity tests in the RDG screening tool to analyze the effect of alternative values for the following 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 this change on the results. The degree of change under each scenario can also be input by the user.

In addition, we also include in our uncertainty analysis consideration of the effect of a City Council authorized price-premium for renewable generation sources, as described in greater detail below.

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 CEC gas forecast to help derive the Long-Run Marginal Cost (LRMC) for electricity, the Base, Low, and High electricity price forecasts are derived using the CEC Base, Low, and High gas forecasts in our LRMC calculations. The resulting Base, High, and Low electricity price forecasts are shown in Figure 93.
6.3. Transmission Prices

In the case of uncertain transmission prices, we used a Low scenario value equal to current transmission costs of $9.16/MWh. CPAU staff deem it highly likely that transmission rates will rise in the near future; beginning in 2006, we use $10.07/MWh (a 10% increase) as our Base Case value to reflect this likelihood. We input a High value at $20/MWh, reflecting considerable uncertainty surrounding the possibility of “nodal” pricing under MD02, as discussed in the distribution 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 5 MW biogas 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.

Below, we also discuss the effect of including a City Council-authorized premium for the procurement of renewable generation resources.

6.6.1. 5MW Biogas

Figure 94 shows the sensitivity range of TRC test results obtained for a 5 MW biogas Wartsila 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, multiple inputs can be varied at the same time using the RDG screening tool.

![Figure 94: Net benefit range for key uncertainties from the TRC test perspective](image)
As can be observed in Figure 94, the 5 MW biogas unit we screened is not cost-effective under the TRC test in the Base Case but can become cost-effective under a low fuel cost or high transmission avoided cost scenario.

Figure 95 shows the results of the TRC test sensitivity analysis in the form of a 'spider diagram.' As in Figure 94, one can easily discern the effect of a move from Base to High or Low scenarios for any of the input variables. The nucleus of the spider diagram is the Base Case scenario and each 'leg of the spider' represents the effects on the overall net benefit of the RDG installation of a change in that variable while holding all other variables at the Base Case. The spider diagram also allows the reader to discern how large a change in the variable was required to effect the change.

![Figure 95: Sensitivity Analysis For 5 MW Biogas Generator From The TRC Test Perspective](image)

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 $10.07 in the Base Case to $20.00 in the High case. While this is an increase in the transmission price of almost 100%, the ratio is calculated as:
% Change = (TH - TB) / (G OutputB) = 18%

where:

\[ T = \text{lifecycle transmission avoided cost value} \]
\[ G \text{ Output} = \text{lifecycle value of generation savings given the unit’s output} \]
\[ H = \text{High Scenario} \]
\[ B = \text{Base Scenario} \]

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

For the 5 MW biogas unit, fuel costs and transmission costs under the scenario analysis change by a significant amount relative to the generation value of the unit’s output. DG capital cost, in contrast, makes up 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 96 and Figure 97. 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 96: Range Of Net Benefits For 50 Kw Solar PV From The TRC Test Perspective
6.6.3. 1.5 MW Wind Generator

Figure 98 and Figure 99 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 (base case is equal to a 30% capacity factor).
Figure 98: Range Of Net Benefits For A 1.5 MW Wind Generator From The TRC Test Perspective
6.7. **Renewable Generation Premium**

CPAU is authorized by the City Council to purchase up to 20% of its generation resources from renewable sources and to pay a premium above 'generic' market resources up to an average rate impact not exceed 0.5 cents/kWh. Put another way, CPAU may pay a price-premium of up to $25/MWh on the 20% renewables, since this is equivalent to raising the overall cost by $25/MWh = 0.05/kWh. We consider this possibility in our uncertainty analysis in the following manner:

- **An increase in $25/MWh in the avoided costs of generation.** This increase in avoided costs reflects the fact that CPAU would pay up to $25/MWh above market for renewable generation resources and that, therefore, if the renewable generation is obtained through utility or customer installed DG, rather than purchased on the market, CPAU has avoided spending the additional $25/MWh on market purchases.

- **An incentive payment of $25/MWh to customers installing renewable DG behind the meter.** This payment reflects an assumption that, to encourage customer installation of DG, CPAU would provide an incentive equal to the additional value of renewable generation.
6.7.1. Effect on the cost tests

Modeling the $25/MWh green tag value in the manner above has the following effects on the cost tests:

- **TRC Test.** The higher avoided cost will be measured as a benefit, while the incentive payment will be recognized as a transfer and will not have an impact. The net effect will be an increase in benefits, which will increase the number of cost-effective DG options from the TRC perspective. The additional benefits can be thought of conceptually as the value to the community of renewable power sources, explicitly recognized to be $25/MWh. Because this community value is an indirect benefit, the TRC test should more accurately be thought of as a Societal Test when the $25/MWh value is included.

- **Participant Test (Customer Owned DG).** A customer installing DG behind the meter will receive a $25/MWh incentive and will not incur any additional costs. This will have the effect of increasing the number of cost-effective DG options.

- **Participant Test (Merchant Plant).** A merchant plant will receive the market price plus $25/MWh, reflecting the fact that CPAU is willing to pay this amount for renewable generation. The analysis thus assumes that the energy generated from the renewable merchant plant is purchased by the utility for $25/MWh above market price. The merchant plant will not incur any additional costs, so the effect will be to increase the number of cost-effective DG options.

- **RIM Test (Customer Owned DG).** This analysis compares the effect on ratepayers of acquiring the renewable resource through DG, with that of acquiring the renewable resource through the purchase portfolio for $25/MWh above market price (as opposed to a comparison against the purchase of non-renewable resources at market price). The additional $25/MWh in avoided cost is measured as a benefit, and the $25/MWh incentive payment is measured as a cost. The net effect on ratepayers is zero. This is consistent with the notion that the utility (and, by extension, the ratepayer) is indifferent between non-renewable generation at market prices and renewable generation at market prices plus $25.

- **Utility Cost Test (Utility Owned DG).** From the utility perspective, the additional $25/MWh in avoided cost is measured as a benefit, and there is no incentive payment since the DG is utility-owned. This has the effect of increasing the number of options that are cost-effective from the utility perspective.

6.7.2. Results with inclusion of renewable premium

Table 23 and Table 24 show the summary results of our economic screening analysis under Base Case assumptions with, and without, inclusion of the renewable premium.
<table>
<thead>
<tr>
<th>Participant</th>
<th>TRC Test</th>
<th>Participant (Customer or Merchant)</th>
<th>RIM Test (Customer Owned)</th>
<th>UCT Test (Utility Owned)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas - 10kW PEM Fuel Cell</td>
<td>0.01</td>
<td>0.02</td>
<td>0.71</td>
<td>0.01</td>
</tr>
<tr>
<td>Biogas - 10kW PEM Fuel Cell CHP</td>
<td>0.47</td>
<td>0.53</td>
<td>0.69</td>
<td>0.39</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell CHP</td>
<td>0.67</td>
<td>0.75</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell CHP</td>
<td>0.58</td>
<td>0.65</td>
<td>0.69</td>
<td>0.48</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>0.66</td>
<td>0.74</td>
<td>0.69</td>
<td>0.54</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.71</td>
<td>0.02</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell CHP</td>
<td>0.49</td>
<td>0.55</td>
<td>0.69</td>
<td>0.40</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine</td>
<td>0.03</td>
<td>0.04</td>
<td>0.71</td>
<td>0.03</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine w/ CHP</td>
<td>0.79</td>
<td>0.88</td>
<td>0.69</td>
<td>0.63</td>
</tr>
<tr>
<td>Biogas - 500 kW Gas Recip GA-K-500</td>
<td>0.07</td>
<td>0.07</td>
<td>0.71</td>
<td>0.06</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.09</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE w/CHP</td>
<td>1.31</td>
<td>1.47</td>
<td>0.69</td>
<td>0.99</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE</td>
<td>0.10</td>
<td>0.11</td>
<td>0.71</td>
<td>0.10</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE w/CHP</td>
<td>1.34</td>
<td>1.50</td>
<td>0.69</td>
<td>1.01</td>
</tr>
<tr>
<td>Biogas - 5MW Wartsila 5238 LN</td>
<td>0.90</td>
<td>1.01</td>
<td>0.69</td>
<td>0.66</td>
</tr>
<tr>
<td>Biogas - MSW Gassification</td>
<td>0.50</td>
<td>0.35</td>
<td>0.58</td>
<td></td>
</tr>
<tr>
<td>Biodiesel - 500kW DE-K-500</td>
<td>0.15</td>
<td>0.16</td>
<td>0.72</td>
<td>0.13</td>
</tr>
<tr>
<td>Solar - PV-5 kW</td>
<td>0.21</td>
<td>0.16</td>
<td>0.83</td>
<td>0.20</td>
</tr>
<tr>
<td>Solar - PV-50 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - PV-100 kW</td>
<td>0.27</td>
<td>0.24</td>
<td>0.73</td>
<td>0.27</td>
</tr>
<tr>
<td>Solar - Thermal SAIC SunDish 25 kW</td>
<td>0.18</td>
<td>0.14</td>
<td>0.30</td>
<td></td>
</tr>
<tr>
<td>Wind - Bergey WD -10kW</td>
<td>0.16</td>
<td>0.18</td>
<td>0.66</td>
<td>0.16</td>
</tr>
<tr>
<td>Wind - GE 750 kW</td>
<td>0.91</td>
<td>0.91</td>
<td>1.08</td>
<td>1.63</td>
</tr>
<tr>
<td>Wind - GE 1.5 MW</td>
<td>1.08</td>
<td>1.08</td>
<td>1.91</td>
<td></td>
</tr>
</tbody>
</table>
### Table 24: Results Of RDG Screening Under Base Case Assumptions, With Inclusion Of Renewable Premium

<table>
<thead>
<tr>
<th>Participant (Customer or Merchant)</th>
<th>TRC Test</th>
<th>RIM Test (Customer Owned)</th>
<th>UCT Test (Utility Owned)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas - 10kW PEM Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 10kW PEM Fuel Cell CHP</td>
<td>0.67</td>
<td>0.67</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 100 kW SOFC Fuel Cell</td>
<td>0.03</td>
<td>0.03</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 100kW SOFC Fuel Cell CHP</td>
<td>0.95</td>
<td>0.95</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 200kW PAFC Fuel Cell CHP</td>
<td>0.83</td>
<td>0.83</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell</td>
<td>0.03</td>
<td>0.03</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 200kW PEM Fuel Cell CHP</td>
<td>0.94</td>
<td>0.93</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell</td>
<td>0.02</td>
<td>0.02</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 250kW MCFC Fuel Cell CHP</td>
<td>0.69</td>
<td>0.69</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 30 kW Capstone 330 Microturbine</td>
<td>0.05</td>
<td>0.05</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 500 kW Gas Recip GA-K-500</td>
<td>0.09</td>
<td>0.09</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE</td>
<td>0.14</td>
<td>0.13</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 800kW Caterpillar G3516 LE w/CHP</td>
<td>1.86</td>
<td>1.86</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE</td>
<td>0.14</td>
<td>0.14</td>
<td>0.77</td>
</tr>
<tr>
<td>Biogas - 3MW Caterpillar G3616 LE w/CHP</td>
<td>1.91</td>
<td>1.90</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - 5MW Wartsila 5238 LN</td>
<td>1.29</td>
<td>1.28</td>
<td>0.76</td>
</tr>
<tr>
<td>Biogas - MSW Gassification</td>
<td>0.67</td>
<td>0.51</td>
<td>0.79</td>
</tr>
<tr>
<td>Biodiesel - 500kW DE-K-500</td>
<td>0.20</td>
<td>0.19</td>
<td>0.78</td>
</tr>
<tr>
<td>Solar - PV-5 kW</td>
<td>0.28</td>
<td>0.20</td>
<td>0.87</td>
</tr>
<tr>
<td>Solar - PV-50 kW</td>
<td>0.36</td>
<td>0.29</td>
<td>0.78</td>
</tr>
<tr>
<td>Solar - PV-100 kW</td>
<td>0.36</td>
<td>0.29</td>
<td>0.78</td>
</tr>
<tr>
<td>Solar - Thermal SAIC SunDish 25 kW</td>
<td>0.24</td>
<td>0.26</td>
<td>0.41</td>
</tr>
<tr>
<td>Wind - Bergey WD -10kW</td>
<td>0.21</td>
<td>0.22</td>
<td>0.73</td>
</tr>
<tr>
<td>Wind - GE 750 kW</td>
<td>1.28</td>
<td>1.64</td>
<td>2.23</td>
</tr>
<tr>
<td>Wind - GE 1.5 MW</td>
<td>1.51</td>
<td>1.51</td>
<td>2.61</td>
</tr>
</tbody>
</table>

As one would expect, the economics improve markedly with inclusion of the premium. In fact, as highlighted in Table 24, three new technologies are cost-effective under the TRC test with inclusion of the premium: the 750 kW wind generator, the 5 MW biogas unit, and the 30 kW microturbine cogeneration unit. The latter is of particular interest as its small size makes it a much more likely candidate for suitable application in the CPAU service area.
7.0 Conclusions

The results of the CPAU 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 CPAU 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. CPAU has a compact distribution system with low losses.
2. Voltage changes from RDG switching on/off are within system tolerance boundaries.
3. No major system upgrades would be required with an RDG installation.
4. The most economically favorable RDG technologies on CPAU system are:
   5. 800 kW Caterpillar 3516 LE with CHP, biogas
   6. 3 MW Caterpillar G3616 LE with CHP, biogas
5. Solar PV has a relatively high 60% coincidence factor in Palo Alto.
6. Some locations within the City can achieve 5% higher effective capacity boost by reducing losses during peak hours. However, if the generator is too large, a negative loss savings could result.
7. Specific optimal locations for RDG may change with the Alma substation closure.
REFERENCES


## GLOSSARY

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>full name</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation</td>
</tr>
<tr>
<td>EEN</td>
<td>Energy Exceeding Normal</td>
</tr>
<tr>
<td>EUE</td>
<td>Expected Unserved Energy</td>
</tr>
<tr>
<td>LRMC</td>
<td>Long Run Marginal Cost</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NYMEX</td>
<td>New York Mercantile Exchange</td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>Pacific Gas and Electric Corporation</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaics</td>
</tr>
<tr>
<td>RDG</td>
<td>Renewable Distributed Generation</td>
</tr>
<tr>
<td>RIM</td>
<td>Ratepayer Impact Model</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>Transmission and Distribution</td>
</tr>
<tr>
<td>TOU</td>
<td>Time of Use</td>
</tr>
<tr>
<td>TRC</td>
<td>Total Resource Cost Test</td>
</tr>
<tr>
<td>UCT</td>
<td>Utility Cost Test</td>
</tr>
<tr>
<td>UE</td>
<td>Unserved Energy</td>
</tr>
<tr>
<td>VOS</td>
<td>Value of Service</td>
</tr>
</tbody>
</table>
APPENDIX A: COST AND PERFORMANCE OF RENEWABLE DG TECHNOLOGIES
1.0 Appendix A: Cost and Performance of Renewable DG Technologies

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

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

1.1.1. Solar

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

Solar-thermal or concentrated solar power (CSP) technologies employ heat to generate power. They consist of a solar concentrator, typically an array of mirrors, and a power converter (such as a turbine), which ultimately drives a generator to produce electricity. Most common among these is the 'solar trough' configuration, in which a parabolically shaped trough of reflective material focuses light on a piped fluid. Though the energy source is intermittent, the heat sink fluid can be stored, allowing these technologies to offer high-value dispatchable power. But given their dependence on economies of scale, these technologies are best suited to multi-megawatt installations1.

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

1 http://www.energylan.sandia.gov/sunlab/overview.htm#tower
technologies, while presently expensive, they employ relatively conventional components that show promise of improving economic competitiveness in the near term.

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

Wind turbines typically produce AC power via induction or synchronous generators. Induction generators are simpler, but require reactive power from the grid, while 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.

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

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

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

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

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

- Gasification – the substance is heated in the absence of oxygen to produce a mixture of hydrogen, carbon monoxide, and methane.
- Anaerobic digestion – bacteria consume the biomass and produce methane. This occurs naturally in landfills.
- Pyrolysis – a chemical/thermal process 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.

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

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

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

- **Phosphoric Acid (PAFC)** – these have been commercially available since the early 1990’s. They operate around 200°C. PAFCs require an external reformer.

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

- **Molten Carbonate (MCFC)** - due to 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.

### 1.1.6. Performance characteristics

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

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0.001-0.10</td>
<td>0.025 - 80</td>
<td>0.05-3.0</td>
<td>0.001-0.25</td>
<td>0.25-3</td>
<td>0.025-0.30</td>
<td>0.05-10</td>
<td>50-250</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel</td>
<td>none</td>
<td>none</td>
<td>none</td>
<td>biogas</td>
<td>biogas</td>
<td>biogas</td>
<td>biodiesel</td>
<td>gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Installed Cost ($/kW)</td>
<td>Heat rate (Btu/kWh)</td>
<td>O&amp;M ($/MWh)</td>
<td>Cogeneration (Btu/kWh)</td>
<td>NOx emissions (lb /MWh)</td>
<td>CO2 emissions (tC/MWh)</td>
<td>Construction Time</td>
<td>Average Annual Capacity Factor (%)</td>
<td>Start-up time (sec)</td>
</tr>
<tr>
<td>-----------------------</td>
<td>------------------------</td>
<td>---------------------</td>
<td>-------------</td>
<td>------------------------</td>
<td>------------------------</td>
<td>-----------------------</td>
<td>-------------------</td>
<td>-----------------------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td></td>
<td>6,675-8,650</td>
<td>N/a</td>
<td>5</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>days</td>
<td>22%</td>
<td>intermittent</td>
</tr>
<tr>
<td></td>
<td>5,700</td>
<td>N/a</td>
<td>10 - 23.0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>months</td>
<td>24%</td>
<td>intermittent</td>
</tr>
<tr>
<td></td>
<td>1,000-6,000</td>
<td>N/a</td>
<td>10</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>weeks</td>
<td>36%</td>
<td>intermittent</td>
</tr>
<tr>
<td></td>
<td>N/a</td>
<td>N/a</td>
<td>N/a</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>years</td>
<td>42%</td>
<td>intermittent</td>
</tr>
<tr>
<td></td>
<td>5,346-12,507</td>
<td>9000-10,000</td>
<td>15</td>
<td>0</td>
<td>0.02</td>
<td>0.13-0.15</td>
<td>days</td>
<td>96%</td>
<td>“Fast”</td>
</tr>
<tr>
<td></td>
<td>5,731-8,338</td>
<td>7000-8000</td>
<td>10</td>
<td>0.10-0.12</td>
<td>0.01</td>
<td>0.10-0.12</td>
<td>months</td>
<td>96%</td>
<td>“Fast”</td>
</tr>
<tr>
<td></td>
<td>2,200-2,600</td>
<td>11,000-14,000</td>
<td>10</td>
<td>0.16-0.20</td>
<td>1</td>
<td>0.16-0.20</td>
<td>days</td>
<td>96%</td>
<td>“Slow”</td>
</tr>
<tr>
<td></td>
<td>250-500</td>
<td>8000-11,000</td>
<td>20</td>
<td>0.16-0.16</td>
<td>15-20</td>
<td>0.16-0.16</td>
<td>weeks</td>
<td>95%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>350-450</td>
<td>7000</td>
<td>5</td>
<td>0</td>
<td>0.06</td>
<td>0.10-0.15</td>
<td>days</td>
<td>99%</td>
<td></td>
</tr>
</tbody>
</table>