Economic Costs and Benefits of Distributed Energy Resources

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Technical Update, December 2004

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PRODUCT DESCRIPTION

The goal of this technical update is to provide an objective quantitative analysis of the current costs and benefits of DER, and thereby identify the factors that have the greatest impact on DER's cost-effectiveness. For the purposes of this analysis, DER as defined herein, are small generation units (1kW to 50MW), typically sited on the local T&D system and operated in parallel with the utility system. Energy storage technologies are not included in this technical update but may be considered in future updates.

This update provides an estimate of the range of costs and benefits associated with DER applications. This enables us to determine what DER has to be capable of technically or economically to capture specific benefits. We show how each cost (or benefit) changes the overall economics of DER from both utility and customer perspectives, thereby identifying applications that are likely to be cost-effective today and in the near future.

Results & Findings

This report represents a technical update to prior research conducted by EPRI on DER economics and would be useful to all industry stakeholders including funding organizations, policy makers, utility planners, DER vendors, and customers considering DER. The findings in this report include the key variables that affect DER cost-effectiveness from the utility and customer perspectives. These findings are particularly applicable to any party that is interested in further deployment of DER.

One of the most salient findings of this cost and benefit analysis is that the utility net benefit is negative for most cost-effective customer DER applications. The current DER landscape[1] indicates that the two most widespread applications of DER are 1) combined heat and power with waste gas usage and 2) back-up power applications. These applications tend to be customer-driven due to the favorable economics for the DER owner. Only those DER applications that have positive net benefits from a societal perspective (TRC test) have enough value to be potentially cost-effective from both the customer and utility perspectives.

Potential ways to address this disparity involve a combination of several actions including:

1. Reducing DER capital costs
2. Increasing DER operating efficiency
3. Better deployment of DER resources to capture additional value streams

[1] Distributed Energy Resources: Current Landscape and a Roadmap for the Future, 1008415, November, 2004.

While reducing capital costs and increasing efficiency of DER technologies is ongoing within the DER industry, better deployment of these resources can be pursued concurrently. Given the installed base of DER today, it is clear that DER vendors have been able to effectively target DER to meet the customer's needs for combined heat and power or back-up power. However, the lack of DER sited as utility resources indicates that there is an opportunity to capture more value for utilities using DER.

Applications, Values & Use

This technical update shows the current economic value that DER is able to provide to both customers and utilities. Presently, the most cost-effective DER applications are found on the customer-side of the utility meter and these valuable applications are highly site specific. As such, the existing installed base of DER is heavily weighted to customers and not utilities. The utility's ability to capture potential DER benefits is a crucial factor when considering greater deployment of DER within the electric grid. Several potential future areas of study exist to address DER's ability to provide value to utilities which include, but are not limited to, the following topics.

1. Siting DER in the best location on the electrical system within utility planning process
2. Allowing DER to participate in multiple markets for utility services
    a. Near term opportunities: capacity markets, resource adequacy, emission credit markets
3. Establishing DER as a potential resource for improving islanding and reliability on utility system
4. Developing regulatory and rate structures that facilitate DER siting and use by utilities as:
    a. A part of the T&D system
    b. A utility resource (generation, capacity, resource adequacy, and emissions)

EPRI Perspective

This technical update is one of three technical reports prepared in 2004 by EPRI's DER Program. The other two include: Distributed Energy Resources: Current Landscape and a Roadmap for the Future (1008415); and Low-Emissions Technologies for Distributed Generators (1011341). Together, all three reports will provide industry stakeholders with an informative assessment of the DER landscape and future directions that could complement and add value to the electricity enterprise.

Keywords

Distributed energy resources
Distributed generation
Cost and benefit analysis
Peak shaving
Combined-heat and power
Renewable generation
Net benefits

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1
INTRODUCTION

At present there are over 234 gigawatts of distributed energy resource (DER) in the U.S, with the majority of applications installed on the customer-side of the utility meter, either by the facility owners themselves or by third party DER developers.[2] These DER projects offer the potential to lower consumers' energy bills, improve electric reliability, reduce transmission and distribution (T&D) losses and facility investments, and decrease the emission of greenhouse gases (CO_2) and other air pollutants. However, DER's cost-effectiveness is highly case specific and varies by technology, application, and location. Generalized statements about the "cost-effectiveness" of DER, therefore, could be misleading. The goal of this technical update is to provide an objective quantitative analysis of the current costs and benefits of DER, and thereby identify the factors that have the greatest impact on DER's cost-effectiveness.

For the purposes of this analysis, DER as defined herein, are small generation units (1kW to 50MW), typically sited on the local T&D system and operated in parallel with the utility system. Energy storage technologies are not included in this technical update but may be considered in future updates.

This update provides an estimate of the range of costs and benefits associated with DER applications. This enables us to determine what DER has to be capable of technically or economically to capture specific benefits. We show how each cost (or benefit) changes the overall economics of DER from both utility and customer perspectives, thereby identifying applications that are likely to be cost-effective today and in the near future.

DER applications can produce grid and system benefits, as well as customer-specific benefits through applications such as standby generation, peak shaving, combined heat-and-power (CHP), prime power, premium power, or renewable power. Table A-1 lists the most common applications and their primary motivating factors.

Table A-1
Motivating Factors for Current DER Installations

DER Application	Project Motivation
Combined Heat and Power (Cogeneration)	Capturing waste heat from on-site DER to offset fuel costs dramatically improves economics.
Backup Reliability	On-site backup power provides benefits to customers with high reliability requirements.

[2] Distributed Energy Resources: Current Landscape and a Roadmap for the Future, 1008415, November, 2004

Peak Shaving	Reducing customer peaks lowers utility demand charges for poor load factor customers.
Renewable Power	Customers who place a high value on generating energy with renewable resources.

While customer-side applications of DER will continue to dominate, 'utility-side' applications are becoming increasingly important in utility resource planning. Depending on location and utility need, DER can provide energy and capacity value to a local T&D system and, to a lesser extent, the bulk transmission system. Table A-2 and Table A-3 present the key economic drivers for customer-side and utility-side DER applications, and indicate the sections of this technical update where those costs and benefits are discussed in detail.

Table A-2
Key Economic Drivers of Customer-side DER Economics

Economic Driver	*Section*
Benefits	
Reducing Utility Bills	*2.1.5*
Waste Heat Use	*2.1.4*
Back-up Reliability Value	*2.1.6*
Renewable Goals and Interests	*2.3.1*
Costs	
Capital and Installation Cost	*2.1.1*
Financing Cost	*2.1.2*
Fuel Cost	*2.1.3*
Other Costs	*2.4*

Table A-3
Key Economic Drivers of Utility-side DER Economics

Economic Driver	*Section*
Benefits	
Market Price of Energy	*2.2.2*
Bulk System Capacity	*2.2.5*
Local Transmission and Distribution capacity	*2.2.3*
Meeting Renewable Standards and Mandates	*2.3.1*
Costs	
Dispatchability and Control	*2.2.1*

Capital and Installation Cost......	2.1.1
Fuel Cost..........	2.1.3
Financing Cost..	2.2.4
Other Costs......	2.4

In addition to 'customer-side' DER and 'utility-side' DER, we examine 'joint' applications where the equipment is located on the customer-side of the meter yet the utility has some level of control to produce utility benefits. Joint-DER applications include both costs and benefits listed in Table A-2 and Table A-3, with the addition of an incentive payment from the utility to the DER customer in return for the availability and dispatch control of the DER.

Figure 1-1 illustrates how a joint DER application could improve DER economics. Without a joint effort, a local area with high marginal cost of service from the utility's perspective may not have any cost-effective customer-side DER applications. However, an incentive payment in return for some assurance that the DER will operate when needed may make the customer DER application economic.

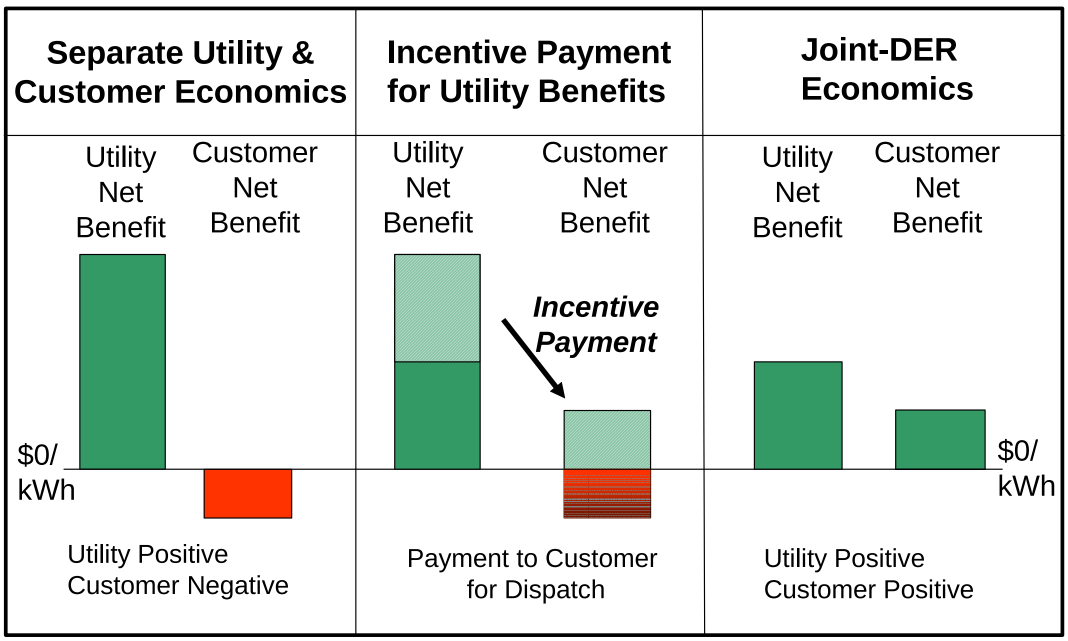


Figure 1-1
Joint DER Applications Can Provide Greater Opportunity for Cost-effective DER Applications. An incentive payment, in return for some level of utility dispatch control, can give the utility an additional resource, and the customer an additional revenue stream.

The focus on joint DER applications has increased lately, as evidenced by the recent and upcoming issuance of request for proposals (RFPs) by utilities in New York and California. Joint DER applications have the most promise in areas with significant utility benefits. Figure 1-2 illustrates the increased opportunities for the joint application at the intersection of the two approaches that can capture both customer-side and utility-side benefits.

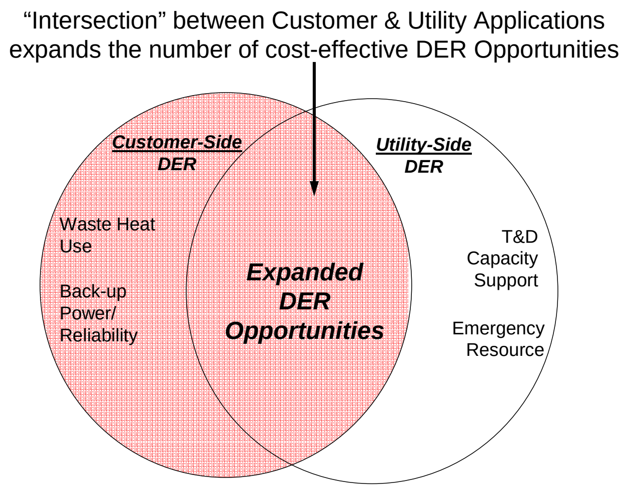


Figure 1-2
Intersection between Customer and Utility DER Applications Increases the Number of Cost-Effective DER Opportunities

There are, however, difficulties with making joint DER applications cost-effective to both the customer and utility. Most utilities classify the reduced revenue from a customer that has installed DER as a cost[3]. Therefore, DER applications need to provide energy, capacity, and other benefits that are greater than the revenue loss for the project to be cost-effective to the utility. Using this approach, we find that it is unusual for a DER application installed on the customer side of the meter to be cost-effective from the utility perspective.

1.1 Key Findings

In real-world applications, DER projects will have individual costs, expectations of benefits, as well as non-monetary drivers that will affect its adoption. In this analysis, we screened numerous DER applications under base case, favorable and unfavorable conditions to evaluate the fundamental economics for the customer and utility perspectives as well as for the joint perspective. While this type of analysis does not identify all cases where DER could be cost-effective, it does provide insights as to the type of applications that are most likely viable from each ownership perspective. Figure 1-3 displays the technologies with the highest net benefit by type (e.g. diesel engine, microturbine, natural gas engine) for customer-side and utility-side DER applications. These results are grouped into applications; peaking/backup, CHP/baseload, and renewable. The error bars around the base case net benefit results indicate the potential range of net benefits given the optimistic and pessimistic input assumptions described in Chapter 2.

[3] This perspective is often referred to as the Ratepayer Impact Measure (RIM). This perspective evaluates whether the utility's rates would have to increase or decrease all other things equal if the DER is installed.

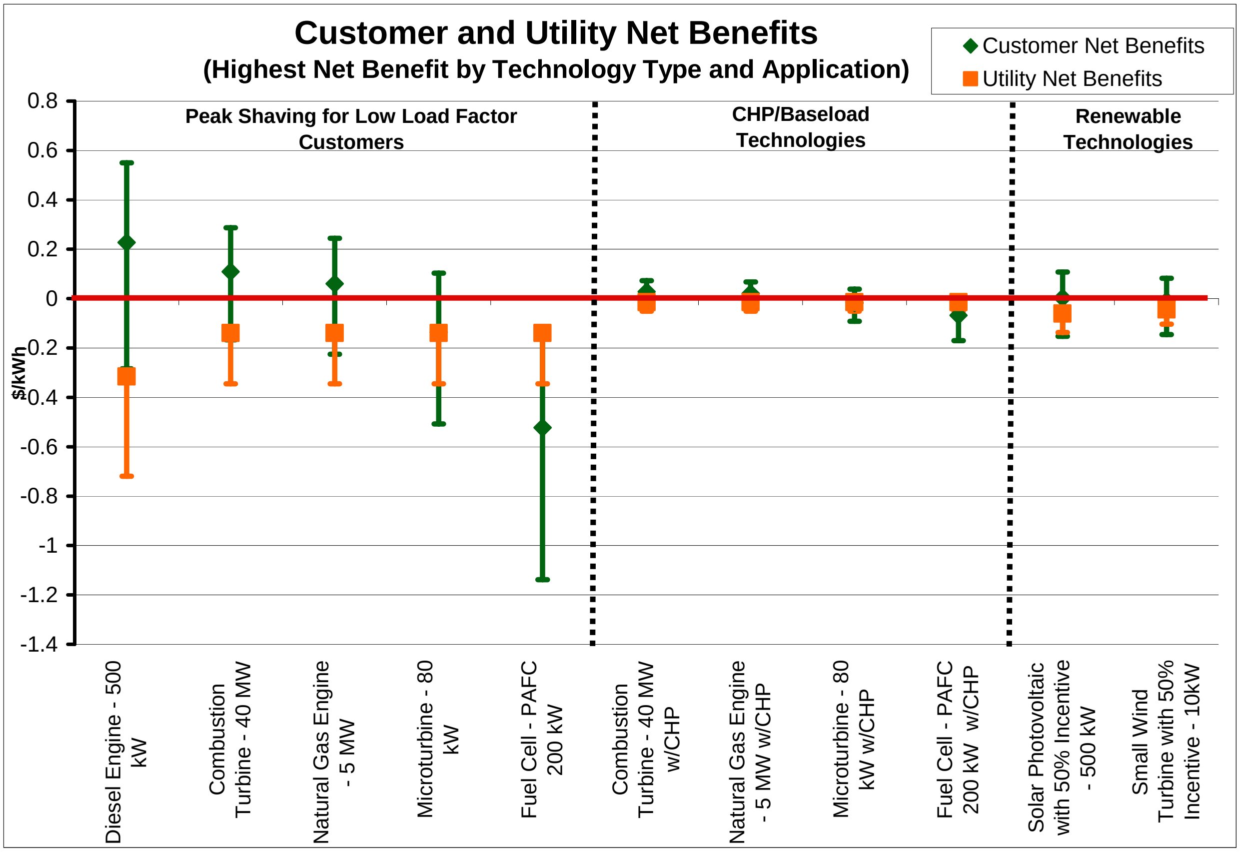


Figure 1-3
Joint Customer-Utility net benefits of DER technologies.

* Note: The technology with greatest net benefit for each type of technology is shown. Values are sorted from the customer-side perspective within DER application category. Error bars represent the sensitivity range tested around the base case scenario. Technologies with overlapping error bars or net benefits that are greater than zero could potentially be a cost-effective DER application.

We further extend this analysis to identify the level of benefits for each type of application that would render the application cost-effective, along with the best current DER technology. Key findings from this analysis are shown in Table A-4. The 'Conditions for Cost-effectiveness' column identifies the economic driver that enables each application to be cost-effective, and the 'Best Current DER Technology' column identifies the best technology. For example, for a back-up application to be cost-effective, the value to the customer must be at least $80/kW-year with a diesel backup technology. Similarly, avoided T&D capacity costs much exceed approximately $100/kW-year in order to be cost-effective. An application that achieves multiple benefits (cogeneration and back-up power, for example) would be able to be cost-effective at less extreme values. We did not include any 'soft-benefits' for renewable applications in this example.

Table A-4
Key DER Application Economic Findings

DER Application	Conditions for Cost-Effectiveness	Best Current DER Technology
Backup Power	Value of backup greater than $80/kW	Diesel (if permit available) Natural Gas Reciprocating Engine
Peak Shaving	Low load factor customers (<20%) High demand charges Low or no standby reservation charge	Diesel Reciprocating Engine (if permit available) Natural Gas Reciprocating Engine
Combined Heat and Power (CHP)	High use of recovered heat to displace fuel (>30%)	Natural Gas Reciprocating Engine with CHP
Renewable	High incentive level (>50%)	Large-scale Solar PV (500kW)
Utility Capacity Support	High value of local capacity relief (>$100/kW-year)	Diesel or Natural Gas Reciprocating Engine Natural Gas Turbine (Mobile DER applications would be helpful)
Joint DER Application	• Very high value of local capacity relief (>$250/kW-year)	• Diesel Reciprocating Engine (if permit available) • Natural Gas Reciprocating Engine

1.2 Recommendations

One of the most salient findings of this cost and benefit analysis is that the utility net benefit is negative for most cost-effective customer DER applications. The current DER landscape indicates that the two most widespread applications of DER are 1) combined heat and power with waste heat usage and 2) back-up power applications. These applications tend to be customer-driven due to the favorable economics for the DER owner. Only those DER applications that have positive net benefits from a societal perspective (TRC test) have enough value to be potentially cost-effective from both the customer and utility perspectives.

From the utility perspective most DER applications under the existing regulations and rate structures tend to either 1) drive up rates for all customers or 2) reduce utility shareholder value. This disparity between cost-effective customer applications and cost in-effective utility applications is what must be addressed if DER is to capture the potential benefits touted by supporters on a widespread scale.

Potential ways to address this disparity involve a combination of several actions including:

1. Reducing DER capital costs

2. Increasing DER operating efficiency

3. Better deployment of DER resources to capture additional value streams

While reducing capital costs and increasing efficiency of DER technologies is ongoing within the DER industry, better deployment of these resources can be pursued concurrently. Given the installed base of DER today, it is clear that DER vendors have been able to effectively target the DER to meet the customer's needs for combined heat and power or back-up power. However, the lack of DER sited as utility resources indicates that there is an opportunity to capture more value for utilities using DER.

Several potential future areas of study exist to address DER's ability to provide value to utility customers, which include but are not limited to the following:

1. Siting DER in the best location on the electrical system within utility planning process

2. Allowing DER to participate in multiple markets for utility services

    a. Near term opportunities: capacity markets, resource adequacy, emission credit markets

3. Establishing DER as a potential resource for improving islanding and reliability on utility system

4. Developing regulatory and rate structures that facilitate DER siting and use by utilities as:

    a. A part of the T&D system

    b. A utility resource (generation, capacity, resource adequacy, and emissions)

2
KEY DRIVERS AFFECTING DER ECONOMICS

In this chapter, we list the drivers central to the economics of DER from the customer-side, utility-side, or joint applications. Inputs derived in this chapter will enter into the cost-effectiveness calculations for each type of DER application. In Chapter 3, the range of net benefits is computed for customer, utility, and joint DER applications given ranges of these key drivers.

2.1 Key Drivers of Customer-Side DER

2.1.1 DER Capital and Installation Cost

The costs to design, purchase, and install DER remains a critical — and often prohibitive – factor in overall DER economics. In this update, we discuss how financing alternatives, high operational efficiency, and low or zero cost fuels can mitigate the upfront capital costs, but the fact remains that the total capital equipment costs for DER are high relative to conventional supply sources.

Our base case assumptions of installed costs of the technologies evaluated in this analysis are shown in Table A-1. While in practice these costs are very site-specific, the assumed costs shown below are a representative range of industry reported technology costs. For each technology, we perform a sensitivity analysis of 30% to 50% higher and lower than the base case installed cost for the economic analysis shown in Chapter 3.

Table A-1
Installed Costs for DER Technologies ($/kW*)

Technology Type	Total Installed Cost $/kW
Conventional Gas Turbines	
Combined Cycle Gas Turbine - 500 MW	$ 610
Combustion Turbine - 5MW	$ 779
Combustion Turbine - 5MW w/CHP	$ 1,024
Combustion Turbine - 25 MW	$ 660
Combustion Turbine - 25 MW w/CHP	$ 800
Combustion Turbine - 40 MW	$ 590
Combustion Turbine - 40 MW w/CHP	$ 700
Combustion Turbine - 100 MW	$ 480
Fuel Cells	
Fuel Cell - PEM 10 kW	$ 5,500
Fuel Cell - PEM 10 kW w/CHP	$ 5,500
Fuel Cell - PAFC 200 kW	$ 4,500
Fuel Cell - PAFC 200 kW w/CHP	$ 4,500
Fuel Cell - MCFC 250 kW	$ 5,000
Fuel Cell - MCFC 250 kW w/CHP	$ 5,000
Microturbines	
Microturbine - 30 kW	$ 2,260
Microturbine - 30 kW w/CHP	$ 2,630
Microturbine - 80 kW	$ 1,710
Microturbine - 80 kW w/CHP	$ 1,930
Diesel Engines	
Diesel Engine - 30 kW	$ 1,290
Diesel Engine - 60 kW	$ 864
Diesel Engine - 500 kW	$ 386
Diesel Engine - 7.5 kW	$ 627
Diesel Engine - 200 kW	$ 416
Diesel Engine - 500 kW	$ 386
Diesel Engine - 1 MW	$ 570
Diesel Engine - 1.5 MW	$ 550
Natural Gas Engines	
Natural Gas Engine - 100 kW	$ 1,030
Natural Gas Engine - 100 kW w/CHP	$ 1,350
Natural Gas Engine - 500 kW	$ 936
Natural Gas Engine - 1 MW	$ 720
Natural Gas Engine - 1 MW w/CHP	$ 950
Natural Gas Engine - 5 MW	$ 700
Natural Gas Engine - 5 MW w/CHP	$ 890
Solar & Wind	
Solar Photovoltaic - 5 kW	$ 8,650
Solar Photovoltaic - 100 kW	$ 6,675
Solar Photovoltaic - 500 kW	$ 4,740
Small Wind Turbine - 10kW	$ 6,055

****Costs shown in January 2004 dollars***

Figure 2-1 plots the information from Table A-1 in ascending order of $/kW installed costs. Though less fuel-efficient than large-scale generation, installed diesel and gas reciprocating engine have lower capital cost quotes than central station plants. Renewable generation technology costs are an order of magnitude higher than large-scale generation, with the per kW installed costs of small solar PV being twenty times the per kW costs of a simple cycle gas turbine. There is significant uncertainty around the installed capital cost quotes; and we suspect that the quotes are relatively optimistic when compared to a current DER project today. Rather than increase the costs arbitrarily, however, we have used installed cost quotes in the base case analysis.

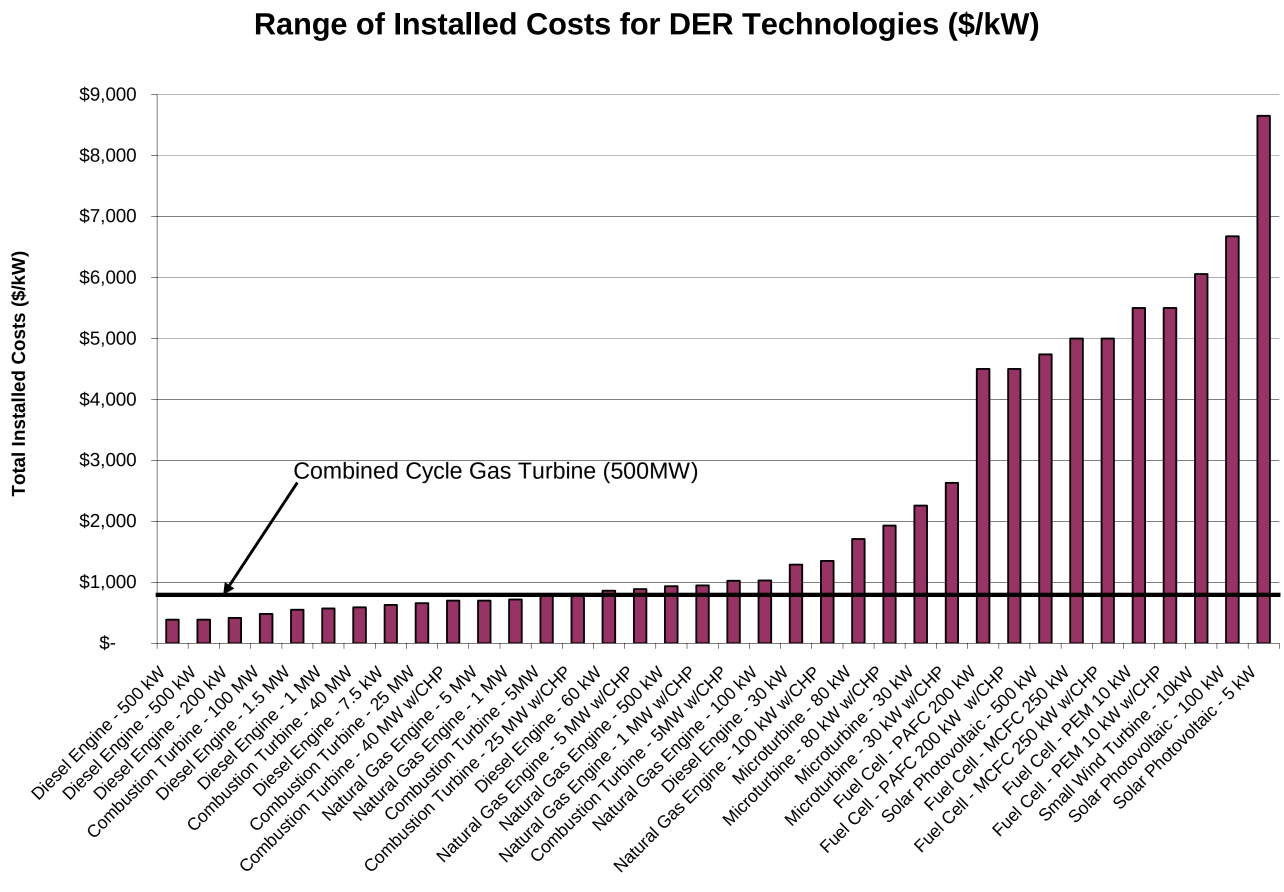


Figure 2-1
Range of Installed Costs of DER Technologies Compared to Combined Cycle Combustion Turbine

Figure 2-2 shows a forecast of the trend of installed costs for selected DER technologies from 2004 to 2015[4], yielding the observation that the costs of the more mature gas engine technologies are not expected to fall significantly in the future. However, the newer technologies such as fuel cells and microturbines should show marked cost reductions in the future.

[4] *Gas-Fired Distributed Energy Resource Technology Characterizations*, National Renewable Energy Laboratory and the Gas Research Institute, October 2003.

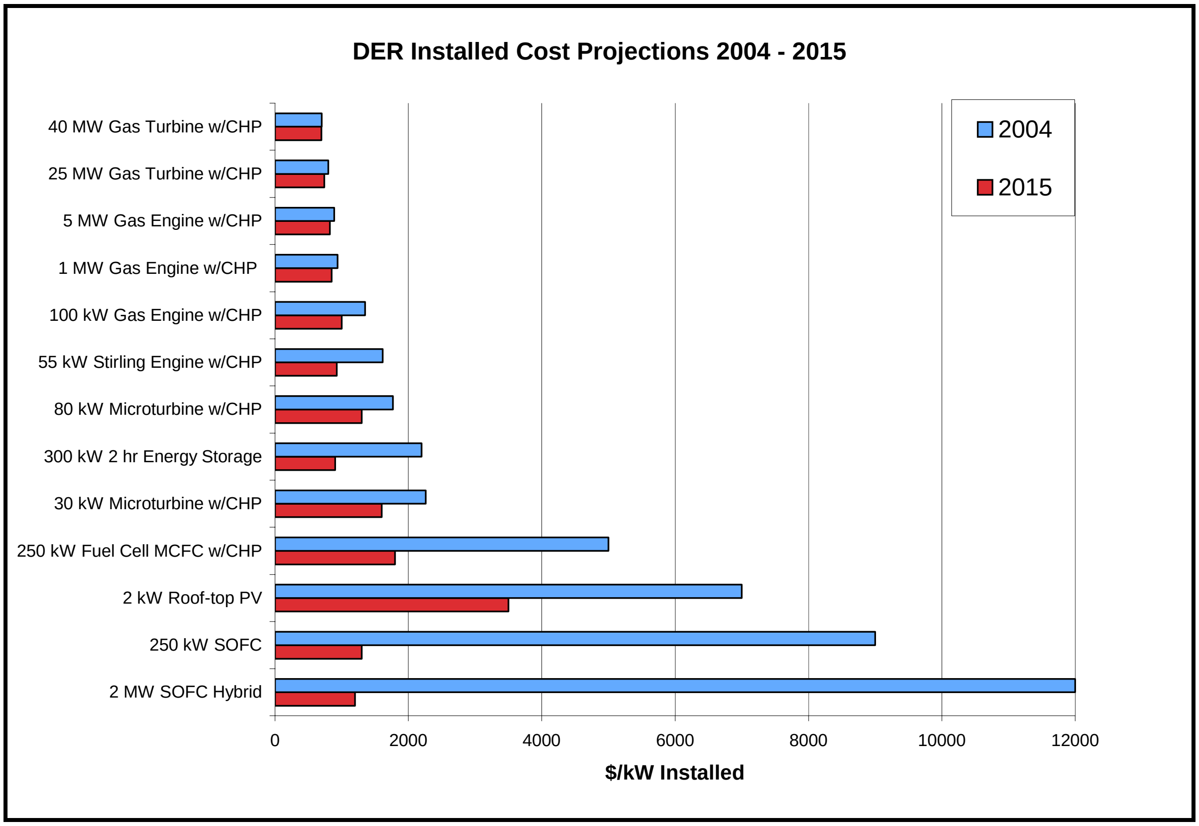


Figure 2-2
DER Installed Cost Projections 2003 - 2030 ($/kW)

2.1.2 Financing Costs

The availability and cost of financing also drives the overall cost effectiveness of a DER application. Rather than paying all of the initial capital costs up-front, an owner of a DER project typically employs some form of financing to improve the project's cash-flow and return. The financing options include[5] :

- Debt financing
- Limited partnerships
- Vendor financing
- Mortgage and home equity loan
- General obligation bond
- Revenue bond
- Lease
- Energy Savings Performance Contract (ESPCs)

[5] Walker, Andy, *Financing Distributed Generation*, Pre-print Conference Paper, National Renewable Energy Laboratory, August 2001, NREL/CP-710-30554.

- Utility and government programs
- Governmental grants

For a residential customer interested in financing a small renewable DER application like solar PV, the capital financing is typically a combination of a home equity loan, utility programs, and/or governmental grants. Whereas for a larger, private commercial DER owner, financing is more varied, typically in the form of debt financing, vendor financing, ESPCs, leasing, as well as the inclusion of grants and utility and government programs. Governments or municipalities acquiring DER often issue bonds to finance projects. Utilities purchasing DER typically debt finance or lease (capital or operating) equipment.

Regardless of the financing source, the prospective DER owner's primary concern is securing the most favorable financing term and cost for their funds. These terms can vary widely depending upon the type of DER, the owner's credit rating, and the project's risks.

We address the range of financing costs by treating the private DER customer financing and utility financing separately. We then test the sensitivity of results from a base case set of financing assumptions. Table A-2 shows the base case customer financing assumptions.

Table A-2
Base Case Customer Financing Assumptions

Borrowing rate	8%
Equity hurdle rate	20%
Leverage ratio (debt/total financing)	80%
Tax rate	45%

The formula used to calculate an after-tax weighted average cost of capital (WACC) from the customer perspective is:

*WACC = borrowing rate * leverage ratio * (1-tax rate) + equity hurdle rate * (1- leverage ratio)*

This calculation using the above assumptions yields a WACC of 7.5%. Assuming a financing period of 10 years, the base case annual capital financing assumption equals 15%. In the low cost financing case, the capital financing is reduced to 12% and in the high cost case it is 17% as shown in Table A-3.

Table A-3
Capital Financing Costs for Customer-Side DER Application

DER Scenario Ranges	Capital Financing
Base Case	15%
High Financing Costs	17%
Low Financing Costs	12%

2.1.3 Fuel Cost

Natural gas prices can significantly affect the cost-effectiveness of a DER project relative to electricity purchased from the utility. Recent increases in natural gas prices and shrinking of regional 'spark-spreads' through the U.S. have worsened the economics of natural gas fired DER applications. Whereas a central station combined-cycle gas turbine (CCGT) project of 250-500 MW typically has a heat rate of about 7,000 BTU/kWh, a DER installation may have a heat rate up to almost 15,000 BTU/kWh for a microturbine. The one exception may be extremely efficient cogeneration systems that displace both electricity and natural gas purchases for hot water and/or steam production. In addition, small DER installations that use lower pressure natural gas pay additional distribution charges; even though some jurisdictions, such as California, charge lower delivery charges to cogeneration DER applications. While certain DER applications may be able to purchase lower-priced fuels like land-fill gas, our analysis focuses on natural gas and diesel due to their prevalence in current DER applications.

A levelized value of natural gas for different customer types, and diesel are provided in Table A-4 prices are based on California, however, the sensitivity range of plus or minus 20% should span fuel prices nationwide.

Table A-4
Base Case Gas Price Forecasts

Base Case Fuel Costs $/MMBtu			
Natural Gas			Diesel
Core Comm	*Core Indust*	*Cogen*	*EG*
$9.12	$6.86	$5.56	$6.50

The levelized values of natural gas and diesel prices are computed from an annual forecast provided in Table A-5[6].

[6] The natural gas price forecast values were forecasted using NYMEX futures for electric generation (Henry Hub + Basis Swap to Southern California + Transportation Charge) for 2004-2009. The values for core commercial, core industrial, and cogeneration natural gas differ due to the additional delivery charges above the cogeneration rate for electric generation and are provided in the California Energy Commission (CEC) forecasts used beyond 2009. Diesel price forecasts are based upon the Department of Energy, Energy Information Administration, Annual Energy Outlook 2003's Diesel Price forecast for the pacific region.

Table A-5
Fuel Costs for DER Applications

Fuel Costs $/MMBtu Nominal				
	Natural Gas			Diesel
Year	*Core Comm*	*Core Indust*	*Cogen*	*EG*
2004	$ 9.67	$ 7.58	$ 6.37	$ 6.28
2005	$ 9.57	$ 7.40	$ 6.16	$ 5.88
2006	$ 9.19	$ 6.96	$ 5.67	$ 6.23
2007	$ 9.12	$ 6.80	$ 5.46	$ 6.37
2008	$ 8.79	$ 6.51	$ 5.17	$ 6.50
2009	$ 8.66	$ 6.35	$ 5.01	$ 6.62
2010	$ 8.67	$ 6.32	$ 4.98	$ 6.74
2011	$ 8.81	$ 6.50	$ 5.17	$ 6.89
2012	$ 8.98	$ 6.65	$ 5.36	$ 7.06
2013	$ 9.26	$ 6.90	$ 5.57	$ 7.29
2014	$ 9.46	$ 7.12	$ 5.81	$ 7.48
2015	$ 9.71	$ 7.35	$ 6.04	$ 7.72
2016	$ 10.00	$ 7.62	$ 6.29	$ 7.91
2017	$ 10.17	$ 7.78	$ 6.45	$ 8.15
2018	$ 10.55	$ 8.16	$ 6.82	$ 8.34
2019	$ 10.88	$ 8.45	$ 7.09	$ 8.68
2020	$ 11.20	$ 8.73	$ 7.38	$ 8.96
2021	$ 11.53	$ 9.04	$ 7.66	$ 9.13
2022	$ 11.90	$ 9.38	$ 8.01	$ 9.36
2023	$ 12.25	$ 9.70	$ 8.33	$ 9.60

Figure 2-3 highlights the cumulative effects of (a) higher gas prices, (b) higher heat rates, and (c) distribution costs on the ability of DER to compete with central station generation. For this example we compared a 500MW combined cycle gas turbine (CCGT) and gas prices equal to our cogeneration rate, with a DER application with a core commercial gas price. If the heat rate for the CCGT is approximately 7,000 BTU/kWh and the DG application is 12,000 BTU/kWh, the cost to generate electricity differs by $0.07/kWh. In areas with lower cost central station plant on the margin (e.g., coal), this difference would be even greater, necessitating additional benefits to compensate for DER applications with higher fuel cost differentials. Clearly, it is difficult to impossible for small DER to be cost competitive to the wholesale power system based on energy cost alone.

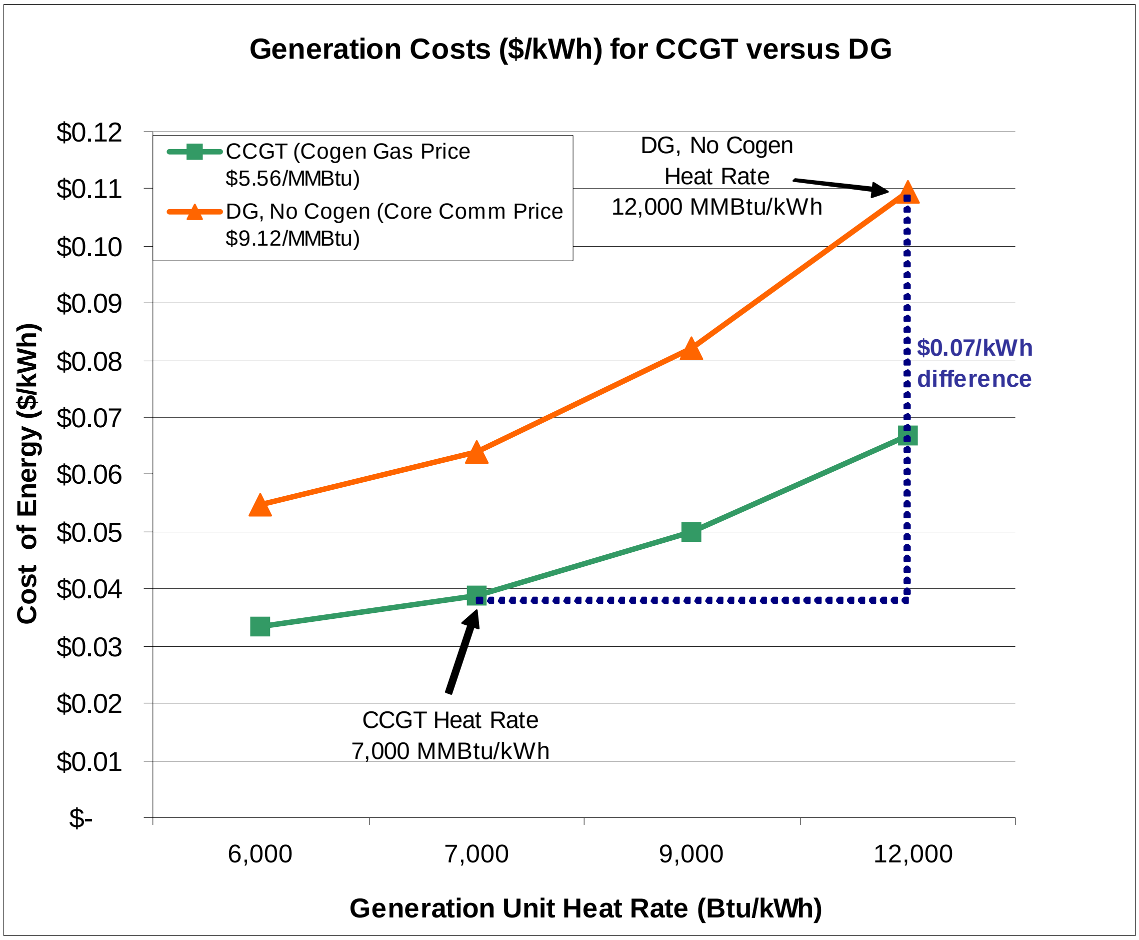


Figure 2-3
DER Generation Costs compared to CCGT at different fuel price levels

2.1.4 Value of Waste Heat

Adding waste heat recovery to a DER installation can greatly improve its fuel efficiency. The waste heat from a CHP application is typically used for hot water or steam at the customer site and displaces the cost of purchasing natural gas or some other fuel to heat the water. The range of value these CHP installations provide depends on two critical factors; (1) the amount of usable waste heat that can be captured from the generator, and (2) the cost of the fuel being displaced. Depending on the technology and application, up to 35% to 40% of the value of the fuel can be captured with DER. Table 2-6 shows the range of gain per kWh generated ($/kWh) for different avoided fuel costs and waste heat recovery potential. For example, at a fuel cost of $10/MMBtu and 40% waste heat recovery; there is an additional $0.05/kWh of value. Note that even in this extremely optimistic case of fuel prices and heat recover, the value of waste heat recovery does not offset the $0.07/kWh higher energy costs in our comparison to central station generation. Within the range of ‘replaced fuel cost’ and ‘amount of energy recovered as usable waste heat, shown in the thermal savings can vary significantly between $0.005 - $0.05/kWh.

Table A-6
Value of Waste Heat Recovery ($ per kWh generated)

		Replaced Fuel Cost ($/MMBtu)			
		$ 4.00	$ 6.00	$ 8.00	$ 10.00
% of DER Energy in Fuel Recovered as Usable Waste Heat	10%	0.005	0.008	0.010	0.013
	20%	0.010	0.015	0.020	0.025
	35%	0.013	0.019	0.025	0.031
	30%	0.015	0.023	0.030	0.038
	35%	0.018	0.026	0.035	0.044
	40%	0.020	0.030	0.040	0.050

Assumption 1: DER Heat Rate of 10,040 Btu / kWh (Based on 1MW Recip with CHP)
Assumption 2: Replaced End Use Efficiency of 80%

We incorporate the value of waste heat as a percentage of energy recovered as usable waste heat in our economic analysis of cogeneration. In the optimistic case, the percentage is set to the maximum expected waste heat recovery for a particular technology (22% to 49% depending on technology). The base case is set to 85% of this value, and the pessimistic case at 70%. Note that the lower the efficiency of the energy generation, the higher the potential for waste heat recovery, precisely because there is relatively more waste heat to be recovered.

2.1.5 Reducing Utility Bills

Of course, customer-side DER does not compete directly with central station generation as in our last examples. Customer-side DER competes instead with the utility tariff for energy delivered to the customer location. Lowering utility bills is a main driver for customers looking to install DER. The rate design of the utility serving the customer is critical to achieving bill reductions. Unfortunately, a comparison of average utility rates and DER costs does not provide a meaningful measure of the DER application's ability to reduce utility bills. A more complete assessment of the actual tariff structure must be made. Typical rate design for commercial customers with DER includes a customer charge, an energy rate, and a demand charge. Utilities are also increasingly implementing a standby reservation charge for DER installations. Each of these rate components, along with the operational configuration of the DER technology, affects the bill reduction potential for a given DER application.

To illustrate the effects of varied rate structures on different types of DER applications, we compare DER costs with utility bill savings for four common rate forms. Using four rate structures, we look at two types of DER applications; a baseload (cogeneration) application and a peaking application. In both cases, we compare the DER costs with the following rate structures;

- Rate 1 is simply an energy charge of $0.12/kWh.
- Rate 2 is an energy charge of $0.052/kWh plus a demand charge of $20/kW-month (Note that this is equivalent to $0.12/kWh for a 40% load factor customer).
- Rate 3 is Rate 2 plus the addition of a standby reservation charge of $3/kW-month.

- Rate 4 is Rate 2 plus an annual ratcheted demand charge[7].

2.1.5.1 BASELOAD CHP DER EXAMPLE

The bill savings and the net DER costs after waste heat recovery are shown in Figure 2-4 for a 1MW natural gas fired engine with waste heat recovery, also called a combined heat and power (CHP) application. For this type of application, which would typically operate at high capacity factors, the energy charge only rate yields the greatest bill savings. We compute the demand charge savings for Rate 2 and 3 assuming the best case for the DER customer (1kW of demand charge reduction for every 1kW of DER). In this case, lower, but still positive, savings are achieved. Without any demand charge reduction as in Rate 4, the cost of the DER is higher than the bill savings.

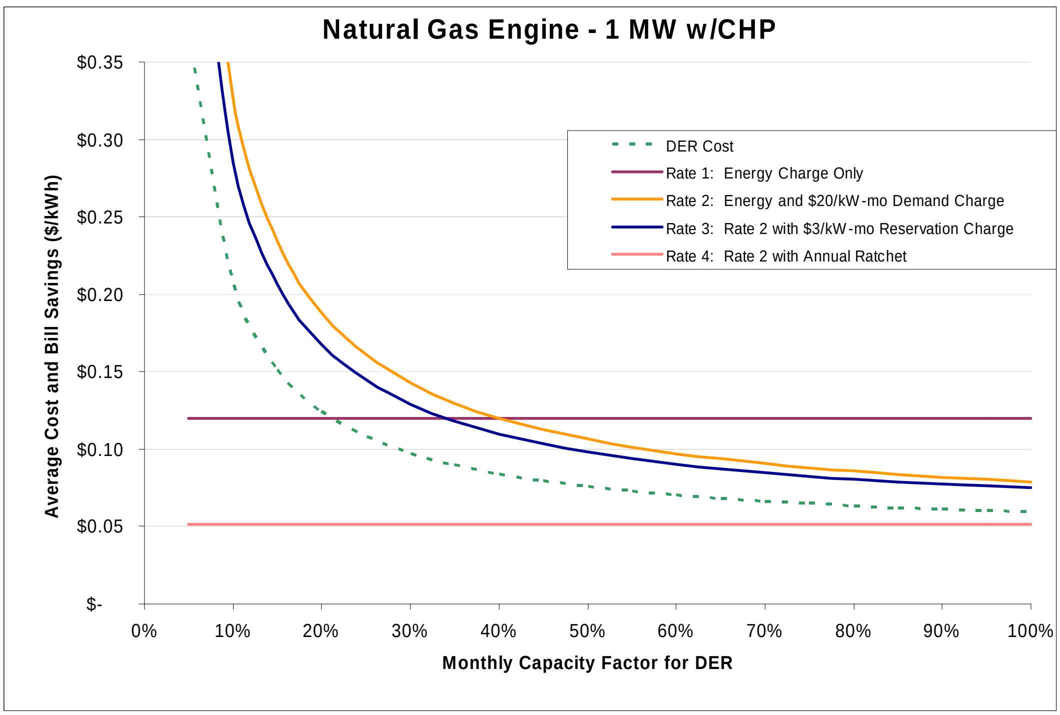


Figure 2-4
Baseload/Cogeneration Avoided Utility Rate and DER Cost for a 1 MW Reciprocating Engine with CHP

2.1.5.2 PEAKING DER EXAMPLE

A different DER approach for low load factor customers is reducing utility bills by using DER only when they have the highest demand in order to reduce demand charges. In our example, a customer could install a 500kW natural gas generator and operate it during times when the load is highest. Figure 2-5 shows the cost of operating the DER, and the customer bill savings for the same rates as in the baseload example. The approach provides a very small savings at capacity

[7] For the annual ratchet demand charge rate, we assume that the DER is unavailable at least once a year at the customer peak and therefore there are no demand charge savings for the DER application.

factors less than 15% for Rate 2 (demand and energy charge rate), but the addition of a standby charge eliminates the potential savings. In some areas of the United States it may be possible to operate a similarly sized diesel generator for less and achieve higher net savings.

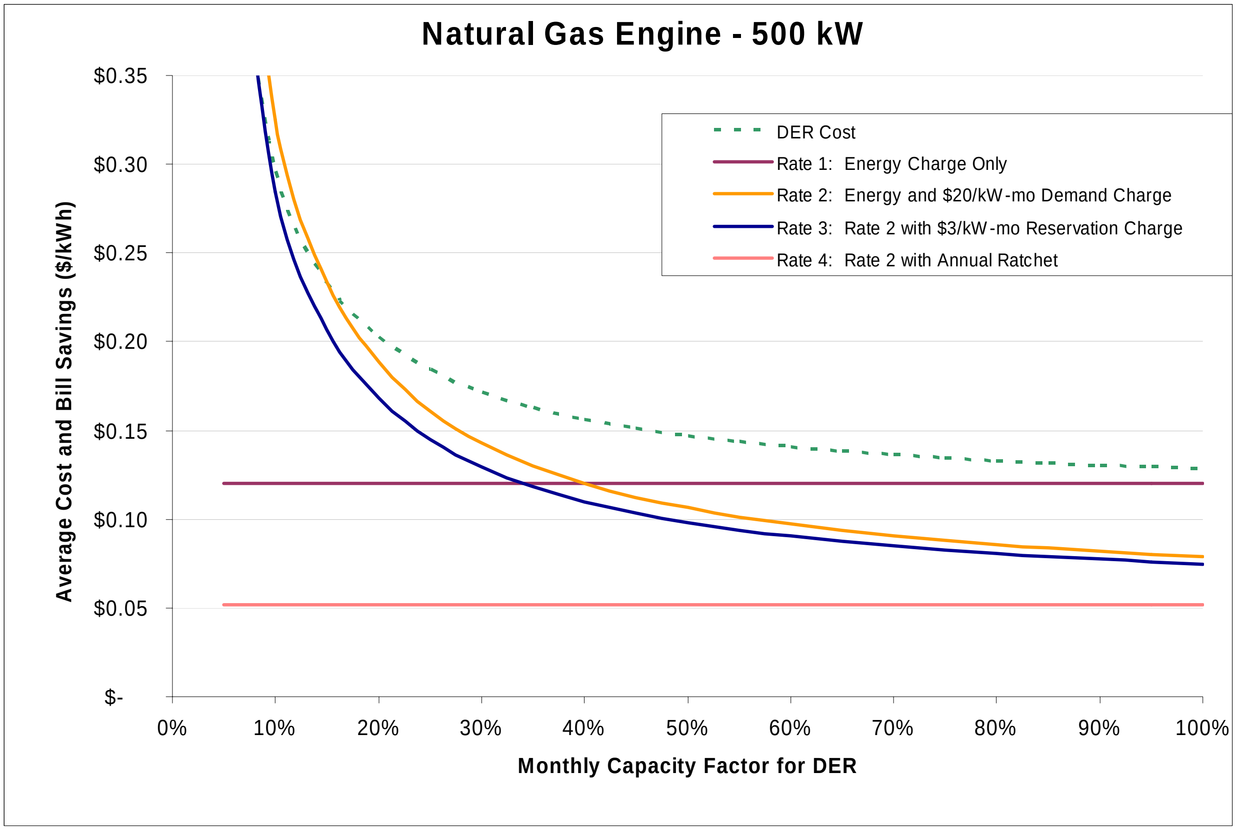


Figure 2-5
Peaking Avoided Utility Rate and DER Cost for a 500kW Natural Gas Engine

The two different examples, one a baseload cogeneration application and the other a peak shaving application with no waste heat recovery, demonstrate that the benefit or value of reducing utility bills is both customer— and utility—specific. Peak shaving applications on their own only make economic sense for the very low load factor customers on rates with high demand charges. Cogeneration opportunities may exist, but only for customers with a strong need for waste heat and baseload power, with high rates relative to fuel costs. In both cases, the addition of an annual demand ratchet eliminates the potential for the DER to compete with the utility rates on its own.

2.1.6 Backup Reliability Value

Reducing the utility bill is not the only potential benefit or driver of new DER applications. An additional driver of customer-side DER is backup power and improved reliability in the event of a utility outage. Costs of interruption vary for each customer. Outage costs to commercial and industrial customers may include lost sales, reduced manufacturing output, spoiled inventory, damaged equipment, extra maintenance, idle labor, and overtime to make up production. Costs imposed to residential customers may include spoiled foods, substitute heating and lighting costs, and inconvenience. Though difficult to quantify, improved reliability offers real value to the individual customer.

We have captured the backup reliability value using a simple approach illustrated in Table A-7. If we assume that the customer perceives their backup to be worth $50,000 per year and they require a 500 kW unit for this backup service, the resulting value of the DER unit is worth $100/kW. If the customer expects to rely on this backup resource 4 hours per year, then the value would be $25/kWh for the DER. Generally sited ranges of values are $5/kWh for residential, $50/kWh for commercial, $20/kWh for industrial, and $10/kWh for agricultural.[8]

Table A-7
Customer-side DER Backup Reliability Value

Backup Reliability	
Value per Year of Backup ($)	$ 50,000
Size of Required DG system (kW)	500
Value per kW of DG system ($/kW)	$ 100

In Figure 2-6, we recomputed the DER costs from our 500kW natural gas engine peak shaving example and net the additional value of backup reliability from the DER costs. With the backup value included, the DER cost is dramatically lower for low capacity factor operation. While this is a very simple example, it enables us to view the magnitude of this driver on the economics and, ultimately, the installation of customer-side DER.

[8] Customer outage costs estimates are surveyed in Woo, C.K. and R.L. Pupp (1992) "Costs of Service Disruptions to Electricity Customers", *Energy*, v12n2, 109-126. Recent information is also presented in a recent report from SCE, *Customer Value of Service Reliability Study*, March 1999.

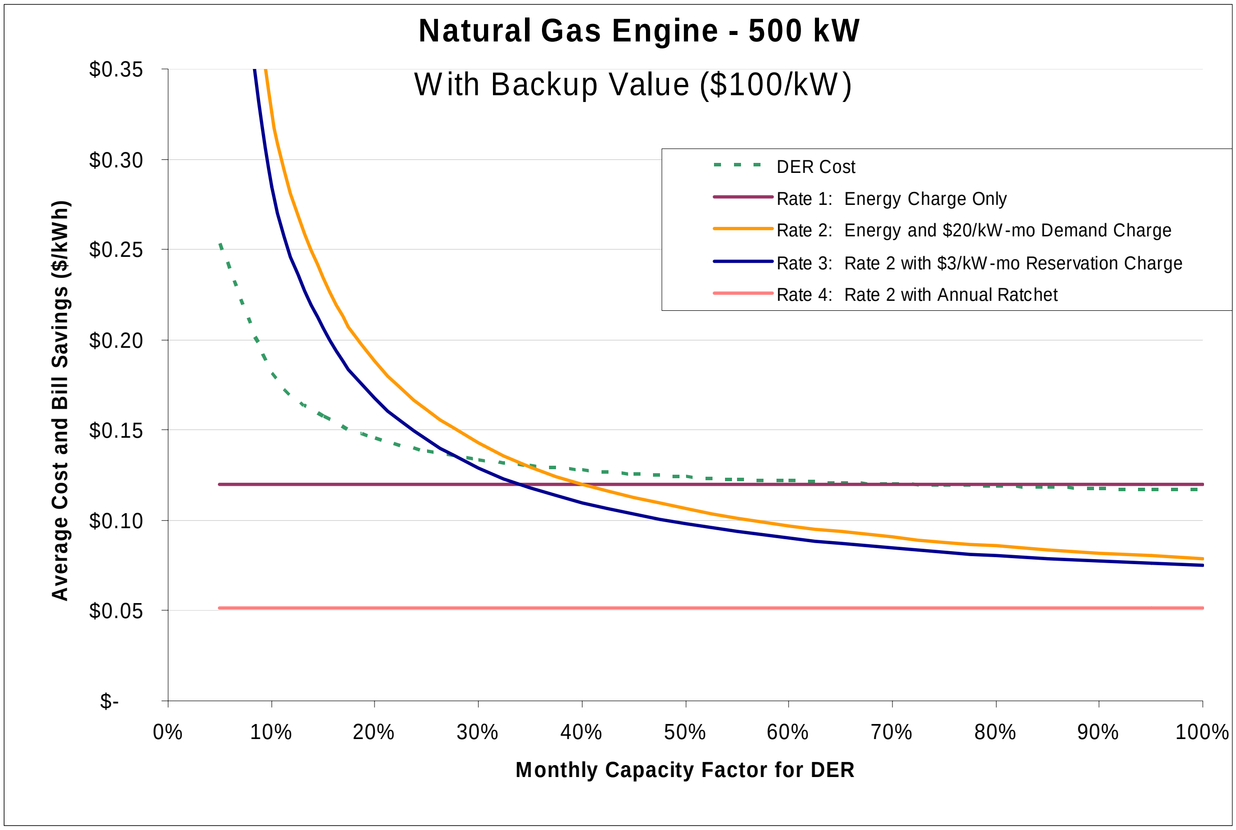


Figure 2-6
500kW Natural Gas Engine for Peaking Application With Backup Reliability Value

2.2 Key Drivers of Utility-Side DER

2.2.1 Dispatchability and Control

When considering utility-side DER installations, the key economic drivers are the energy and capacity savings on the bulk system for reduced use of centralized generation and high-voltage transmission, and the capacity value on the local transmission and distribution systems. Since the cost of generating energy with small-scale DER is typically greater than regional wholesale power prices, as shown in the example illustrated in Figure 2-3, utility-side DER applications can only rarely be justified on energy benefits alone. Utility-side DER must provide other sources of benefit to be cost-effective. Capacity and emergency resource benefits can provide value to the utility. In order to realize capacity value, some level of utility dispatchability and control are necessary prerequisites of DER operation. If a DER unit is unavailable during a peak period or an emergency, then it is of no value as a capacity resource to the electrical system. In the case of renewable DER, while it provides energy and environmental benefits, its lack of dispatchability diminishes its versatility and dependability as a system resource.

2.2.2 Market Price of Energy

Utility-side DER applications located on the transmission and distribution system produce energy and reduce the requirements on large power plants connected at high voltage. The value of the energy produced is determined in the wholesale energy market, either by the DER selling energy directly at the wholesale price (for a large DER unit), or displacing energy a utility would have otherwise purchased. We have forecasted future wholesale energy prices for use in our analysis in conjunction with the natural gas price forecast introduced earlier. The forecast approach uses the methodology introduced in the California Public Utilities Commission (CPUC) Energy Efficiency rulemaking (R.01-08-028) which uses a combination of the electricity forward market prices in the near-term, gas futures prices in the mid-term, and the fixed and variable cost of new combined cycle central station generation in the long-term.[9]

The base case wholesale electricity price estimate is $0.055/kWh. As the year to year market price of energy can fluctuate significantly, these base case prices are varied in the high and low price cases by plus or minus 20%, respectively. This results in levelized annual values of $0.066/kWh and $0.046/kWh.

Table 2-8 shows the annual average base case price forecast. While these prices refer to the SP15 trading point in Southern California, the sensitivity analyses conducted using these values encompasses the expected range of United States wholesale energy prices.

[9] *A Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, January 8, 2004. California Public Utilities Commission, Energy Efficiency Rulemaking Proceeding (R.01-08-028). http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/cpucdraft01082004.pdf

Table A-8
Wholesale Energy Price Forecast (2004-2023)

Wholesale Energy ($/kWh)		
Year	SP15 6/10/2004	
2004	$	0.059
2005	$	0.054
2006	$	0.052
2007	$	0.054
2008	$	0.053
2009	$	0.052
2010	$	0.052
2011	$	0.054
2012	$	0.056
2013	$	0.058
2014	$	0.060
2015	$	0.062
2016	$	0.064
2017	$	0.066
2018	$	0.069
2019	$	0.071
2020	$	0.073
2021	$	0.076
2022	$	0.079
2023	$	0.081
Levelized		**$0.055**

Using these average market prices, we apply an hourly market price shape based upon historic California PX data to enable an evaluation of the energy value of DER with different dispatch patterns. [10] With an hourly market price curve, a utility can determine the optimal number of hours to operate economically by comparing a dispatchable DER unit's variable operating cost against the market price in each hour. Figure 2-7 shows an example for a 1 MW Natural gas engine where the variable cost to operate the engine is $0.10/kWh. With the market price curve, the number of operating hours that the DER unit should operate is 461, yielding an average revenue of $0.15/kWh. Operating at greater than 461 hours is not economical because the variable operating cost would be greater than the market price, thus reducing the average revenue.

[10] Hourly market price shape derived from the California PX hourly NP15 and SP15 zonal prices from April 1998 - April 2000, the period immediately preceding the California Energy Crisis. A description of the methodology is included in: *A Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, January 8, 2004. California Public Utilities Commission, Energy Efficiency Rulemaking Proceeding (R.01-08-028). http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/cpucdraft01082004.pdf

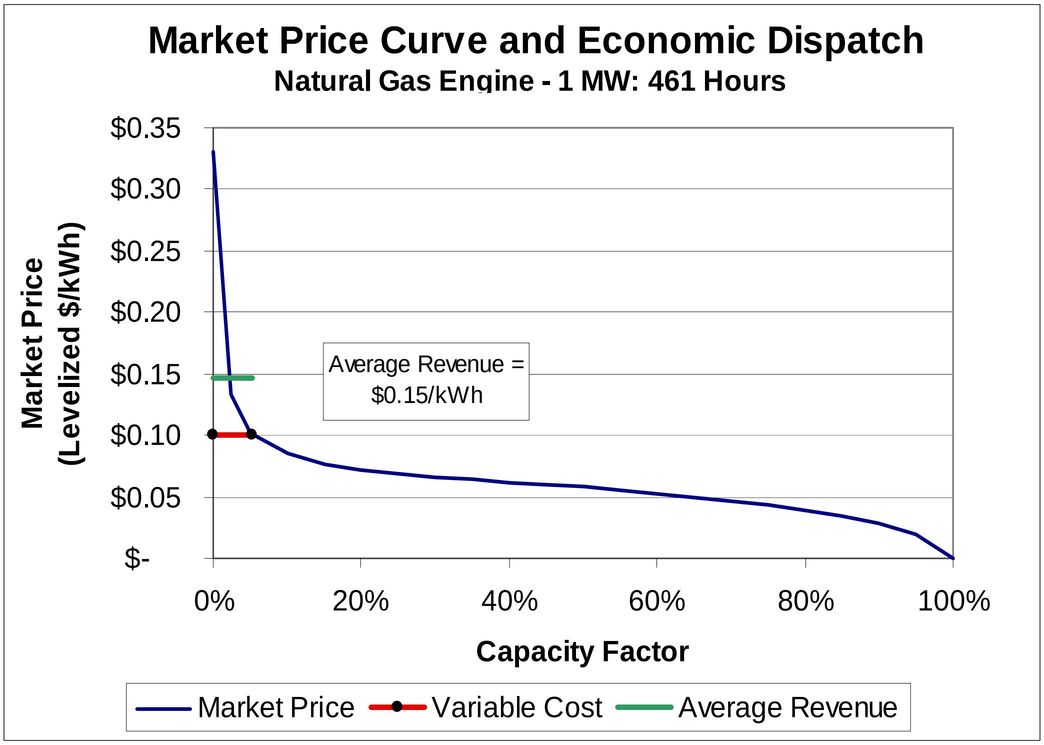


Figure 2-7
Market Price Curve and Economic Dispatch for a 1 MW Natural Gas Engine

2.2.4.1 T&D Energy Loss Savings

In addition to the wholesale energy value, we add an estimate of the reduced losses on the transmission and distribution system. By generating energy close to the customer load, each MWh produced by the DER displaces, at a 10% loss factor, 1.1 MWh on the bulk system. The change in losses due to DER should be estimated with incremental losses (not average) which range from 6% to 12% on most systems. This would equate to an economic benefit of $0.003/kWh to $0.007/kWh using the base case energy price assumptions.

Since losses are proportional to the square of the current load (I^2), the effect of DER on losses is most pronounced during times of peak loading. We apply a loss factor estimate of 10% to DER output during the peak hour to estimate transmission and distribution capacity value.

2.2.3 Transmission and Distribution Capacity

In addition to energy savings, DER projects have the potential to defer utility transmission and distribution investments. However, the avoided T&D capacity value of a DER project is highly area— and time-specific. The ideal distribution planning area for DER is one with high cost distribution investments to meet a relatively small load growth because it implies a high avoided cost per kW of installed capacity.

When coordinated with the utility planning process to provide enough capacity where needed, and then dispatched during times of peak load, the utility-side DER application can defer planned transmission and distribution capacity investments. The value of investment deferral depends on the size of the investment, the required DER capacity, and the utility's cost of capital.

Table A-9, we show the range of transmission and distribution capacity value for different combinations of fully-loaded project cost and the capacity of DER required to defer the project. For example, if a 2MW DER can be installed in an area and defer a $2 million dollar investment, this would save the utility customers $38/kW-year.

Table A-9
Deferral benefit in $/kW-year

		DER Capacity Required to Defer T&D Project (MW)					
		1 MW	2 MW	5 MW	10 MW	20 MW	30 MW
		Values below shown in $/kW-yr					
Full Cost of T&D Project* ($ Millions)	1.0	38	19	8	4	2	1
	2.0	75	38	15	8	4	3
	5.0	189	94	38	19	9	6
	10	377	189	75	38	19	13
	20	755	377	151	75	38	25
	30	1,132	566	226	113	57	38

*T&D investment dollars

Table A-9 provides a range of T&D capacity values, but the result is obviously very dependent on the particular area the DER is located in, and the ability of the DER to provide reliable capacity. In addition, only some areas have capacity constraints that can be addressed through DER installation. In order to examine the impact of DER placement in these areas on DER economics, our analysis includes T&D capacity deferral value only in the optimistic case. The base and pessimistic case does not include a value for T&D capacity deferral because it is rare for this value to be realized through a DER application. However, recent RFPs in New York and pending RFPs in California are testing the feasibility of this approach.

2.2.4 Financing and Capital

To estimate the cost of financing utility-side DER, we assume a weighted average cost of capital of 6% and a 15-year financing period. This equates to a capital carrying charge of 10% in the base case. For the sensitivity testing, the low cost carrying charge for the utility is assumed to be 8% and the high cost case is 15%.

Table A-10
Ranges of the Financing Costs for Utility-Side DER Application

DER Scenario Ranges	Capital Financing
Base Case	10%
High Financing Costs	15%
Low Financing Costs	8%

2.2.5 Wholesale Capacity

Independent System Operators in New York, New England and PJM operate installed capacity (ICAP) markets to ensure adequate resources are available during peak periods of the year. This affords DER owners the opportunity to sell their DER capacity at market value. For example, in New York, the ISO determines the amount of capacity that load serving entities must procure each period as well as the amount of capacity a resource, such as DER, is qualified to supply within the New York Control Area (known as Unforced Capacity). This Unforced Capacity is then sold to load serving entities through NYISO auctions.

The revenue from capacity sales can be a significant benefit for DER located in jurisdictions with wholesale capacity markets. In our economic analysis, we assume a wholesale energy market with firm delivery, making our results applicable to markets with a separate capacity payment. This is because our energy price forecast in the near term is based on forward prices, and in the longer term is based on the sum of fixed and variable costs of a combined cycle gas turbine (CCGT).

2.3 Joint Drivers of DER Value and Additional Values

This section addresses some of the drivers that both the utility and the customer are concerned with in their decision to install a DER application. Such drivers include the value of renewable energy and financial incentives or credits.

2.3.1 Renewable Energy Value

Twelve states in the United States have implemented renewable portfolio standards (RPS) and three other states have voluntary renewable energy targets without any enforcement provisions[11]. For utilities in those states with mandated RPS goals, renewable DER has tangible value as a generation resource to fulfill the RPS targets and avoid penalties associated with not meeting targets. The value of renewable energy exceeds the expected price benchmark. For example, in California, the initial benchmark for utilities was set at a cap of 5.37 cents/kWh. If the actual price of renewables is greater than this cap, the additional costs are paid through public goods charges.

[11] Renewable Energy Policy Project www.repp.org/rps_map.html June 2004

Technologies that use renewable fuels have also motivated customer-side DER applications. Even though the high capital costs of some of these technologies are not completely offset by reduced utility bills, the satisfaction of contributing to a cleaner environment motivates some households and firms to pay more for renewable DER. This differential can be computed and is typically thought of as a willingness to pay for renewable energy. There are also tradable renewable energy credits or 'green tags' that provide a market price and indicate what additional value different types of renewable technologies can provide. Depending on the technology, application, and host-site of renewable DER, a wide-range of potential indirect value streams can be cited including:

- Reduced emissions (Refer to discussion in Section 2.4)
- Feel-good value
- Increased political capital – public relations value
- Meeting renewable, local energy goals
- Energy supply security
- Protection against future environmental regulation
- Dual-land use

In our cost-benefit model, we conservatively set these renewable energy values to zero because they are not readily quantifiable. However, this does not diminish their importance as a driver for both customer and utility-side DER applications.

2.3.2 Financial Incentives / Credits

Incentives/credits are a key benefit to DER customers, and are often required to make the project economically viable. In most cases, these incentives are only available for renewable energy technologies. For example, the California Energy Commission (CEC) has offered the Emerging Renewables Buy-Down Program.[12] This program is ratepayer funded through the Public Purpose Program and provides cash rebates of $4,500 per kW or 50% of system costs (whichever is less) for customers of all classes in investor-owned utility (IOU) service areas who install eligible renewable generating systems. New Jersey has instituted a similar program called the New Jersey Clean Energy Program Incentives, which provides an incentive of a $4,000/kW for wind, sustainable biomass, and solar systems between10kW and 100kW.[13] The economics of the renewable DER technologies in this analysis are completed with and without a 50% incentive on the installed capital cost.

Utilities can provide monetary incentives/credits to DER customers without increasing rates or decreasing returns if the DER applications produce net cost savings to non-participating customers. Figure 2-8 illustrates how an incentive could be set up for a 1-MW natural gas engine under several utility rate schedules. In this figure, the four rate examples are compared to two scenarios of utility avoided cost; (1) only the wholesale energy purchases are avoided, and (2)

[12] See CEC's *Emerging Renewable Resources Account Guidebook,* Vol. 3, 9th Ed, (Sept. 25, 2002), available at http://www.energy.ca.gov/renewables/documents/index.html#greengrid

[13] http://www.njcep.com/html/2_incent.html

both wholesale energy and T&D capacity are avoided as a result of the DER installation. Under Rate 4, with an energy charge, a demand charge, and an annual ratchet, the utility's avoided costs are greater than the reduced revenue in all cases and the utility could purchase energy and T&D cvapacity from the DER without harming other customers. Under Rate 1, with only an energy charge, the utility's avoided costs are higher than the reduced revenue during the peak hours and the utility could purchase peak energy and T&D capacity without harming other customers. If only the wholesale energy purchases are avoided, then DER is economic operating up to approximate a 15% capacity factor. The economic capacity factor increases to about 25% if T&D capacity is added to the wholesale energy avoided costs. Under Rates 2 and 3, the utility cannot avoid enough costs under any capacity factor to make economic use of this DER unit.

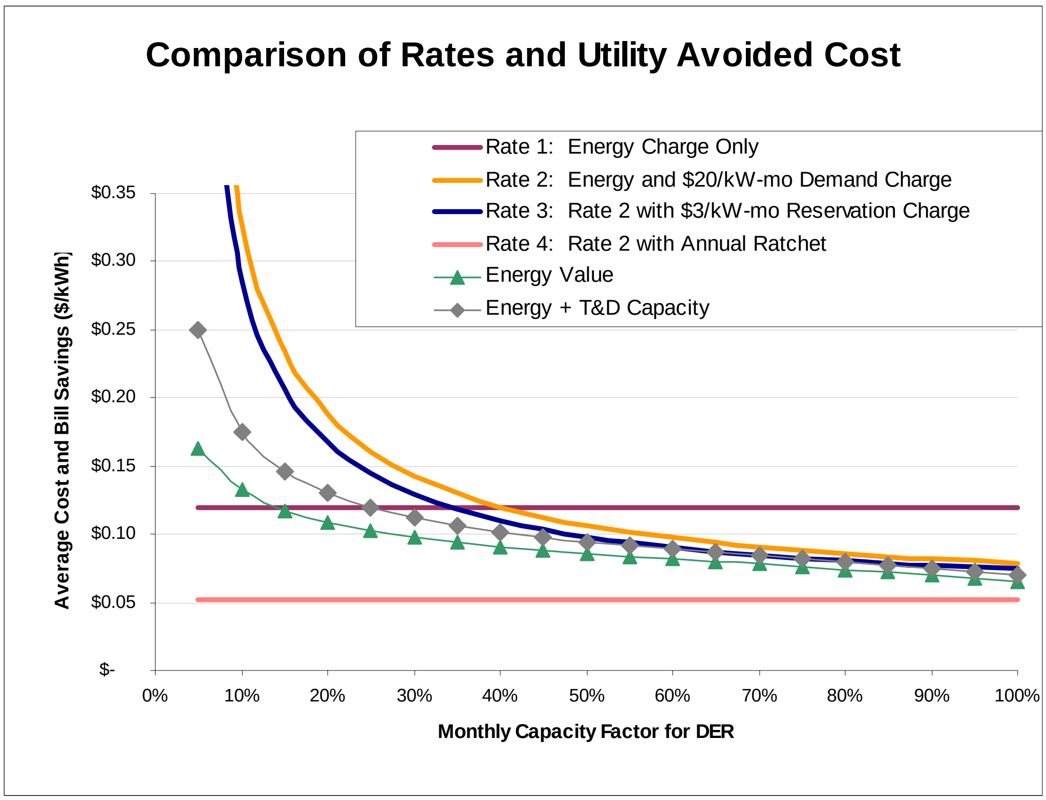


Figure 2-8
Comparison of Utility Rates and Avoided Costs for a 1 MW Natural Gas Engine

2.4 Additional DER Economic Variables

There are numerous other economic variables to consider when evaluating the economics of DER. However, most of these variables have a second order impact on the cost-effectiveness evaluation of most DER installations. A discussion of some of the frequently discussed DER benefits is provided below.

Improved Utility System Reliability

A majority of sustained outages that customers experience are caused by problems on the local distribution system such as trees or branches falling on wires or cars hitting poles that DER cannot currently address except for the customer with the DER for backup reliability .[14] In general, DER will only be able to reduce the number of outages caused by overloaded utility equipment (usually caused by failure of some equipment and a sudden increase in load on remaining equipment in service). Taken together, outages that are preventable by DER constitute 10-30% of all outages, depending on the utility and the area. A reduction in overloading does not eliminate these outages, but would reduce their frequency.

In addition, DER can reduce the amount of ancillary services (AS) required to reliably operate the generation system. In California, the AS-related benefit ranges from 3% to 5% of wholesale energy prices.[15]

Finally, many utilities have performance incentive schedules based on their annual system reliability indices. The most common metric are the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) values for sustained outages, total number of sustained outages, or maintenance and repair outages per mile of line. However, DER is unlikely to effect a change in these system average reliability indices because the majority of outages, whether due to equipment failure or forces of nature, are likely to occur with or without the DER.

Distribution Power Quality Benefits

DER can provide additional economic value beyond capital deferral and improved reliability if it can improve power quality. Distribution systems are designed to meet an acceptable level of power quality for most customers. However, rising saturation of electronic end-uses (e.g., computers and devices for internet communication and data storage) does mean that power quality deterioration (e.g., low voltage, voltage regulation, reactive power, and harmonics) has an increasing impact. Similar to local transmission and distribution capacity benefits, the potential for DER to provide power quality benefits through DER is very area- and situation-specific. In addition, it is possible (some engineers claim likely) that the DER itself can create power quality problems for adjacent customers on the same distribution feeder. Research into power quality benefits and problems with DER is ongoing (e.g. the DUIT project at the California Energy Commission). Nevertheless, power quality benefits of DER, if any, are typically considered very small.

Avoided Environmental Emissions

The benefit of reduced emissions accrues to those technologies that have fewer emissions than the marginal generation resource on the bulk system. DER technologies must also meet local air quality standards and most pay similar emissions reduction costs, either through purchasing

[14] A change in distribution system design and interconnection standards to allow some level of islanding may allow DER to improve reliability to other customers as well.

[15] *A Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, January 8, 2004. California Public Utilities Commission, Energy Efficiency Rulemaking Proceeding (R.01-08-028).

credits or by installing emissions abatement technologies. Only renewable DER technologies can substantially benefit from reduced emissions compliance costs. Hence, this reduction is typically greatest for renewable technologies (e.g. solar PV) or non-combustion technologies (e.g. fuel cells).

Mitigating and managing pollutant emissions represents a cost that would typically be included in the market price of energy. Exceptions are the value of reduced emissions of currently unpriced or unregulated emissions such as CO_2, which has societal value since it is a greenhouse gas, but not a monetary value in most of the United States. Clean and high-efficiency DER options could be used as part of a regional carbon emission management strategy in the future.

The benefits of reduced emissions for controlled emission components include:

1. Emission reduction credits and offsets

2. Reduced facility permitting costs

Table A-11 displays the potential impact of emissions costs for a typical combined cycle gas turbine with a heat rate of 7,500 Btu/kWh. The $/MWh shows the level of potential economic impact from emission reduction credit purchases on a stationary generation plant. The $/ton cost ranges for NOx, SOx, and PM-10 are the actual emissions offset purchases in California during 2003.[16] The CO_2 costs represent the range of potential future impact of CO_2 regulation; this is notwithstanding that CO_2 is not regulated presently, with no existing economic impact.[17]

Table A-11: Emission Cost Impact for Stationary Combined Cycle Gas Turbine

Emission Type	lb/MWh	$/ton (Emission Reduction Credit)			$/MWh		
	average rate	low	average	high	low	average	high
NOx	0.06	6,000	39,842	140,000	0.18	1.20	4.20
SOx	0.01	1,000	9,146	41,096	0.01	0.05	0.21
PM-10	0.04	299	35,797	191,781	0.01	0.7	3.8
CO2	850	0	8	17	0	3.4	7.2

[16] *Emission Reduction Offset Transaction Cost Summary Report for 2003*, State of California, Environmental Protection Agency, California Air Resources Board, March 2004.
[17] Estimates of carbon dioxide values were obtained from publicly available data in regional markets such as Oregon's Climate Trust, PacifiCorp's Integrated Resource Plan, and other US state values of CO_2. Additionally, we evaluated many of the existing technical-economic and macroeconomic models for estimating the price of CO_2 credits in Kyoto-Protocol Annex I Countries.

3
RANGE OF DER ECONOMICS

This chapter reports a base case costs and benefits for (a) the customer-side DER applications (DER the customer installs), (b) utility-side DER applications (DER the utility installs and connects with the distribution system), and (c) a joint-DER application located on the customer side of the meter, with some level of utility control to capture additional benefits (e.g., local T&D investment deferral).

We present the results for a wide range of technologies, including reciprocating engines (natural gas and diesel), microturbines, larger turbines (5MW to 40MW) with and without waste heat recovery, fuel cells (PEM, PAFC, MCFC) with and without waste heat recovery, photovoltaics, and small wind. For comparison, we also include representative bulk system technologies such as a 500MW combined cycle combustion turbine, and a 100MW combustion turbine.

The remainder of this chapter addresses the following topics:

3.1 Range of Capital and Operating Costs for Each Technology
3.2 Detailed Costs and Benefit for Three Different DER Examples
3.3 Range of Net Benefits for Each Technology, Customer, Utility, and Joint Perspectives
3.4 DER Technology Cost and Performance Assumptions

3.1 Range of Capital and Operating Costs for All Technologies

The cost of energy for each DER technology evaluated in this study includes capital, financing, fuel, and maintenance, net of the value of waste heat recovery. The results in Figure 3-1 are sorted from lowest cost (a 40MW CT with CHP) to highest cost (a 10kW PEM fuel cell). The sensitivity of each technology-specific cost range is driven by a combination of capital cost, financing cost, fuel costs, maintenance costs, and waste heat recovery in favorable and unfavorable cases. The results are also sensitive to the capacity factor assumptions based on the expected range of operation hours for each technology. This comparison reiterates that the costs of DER do not compare with the all-in cost of a 500MW CCGT. However, some DER can be cost-effective relative to retail rates depending on rate structure and level, as well as customer load factor. The input assumptions for each technology are provided in Appendix A.

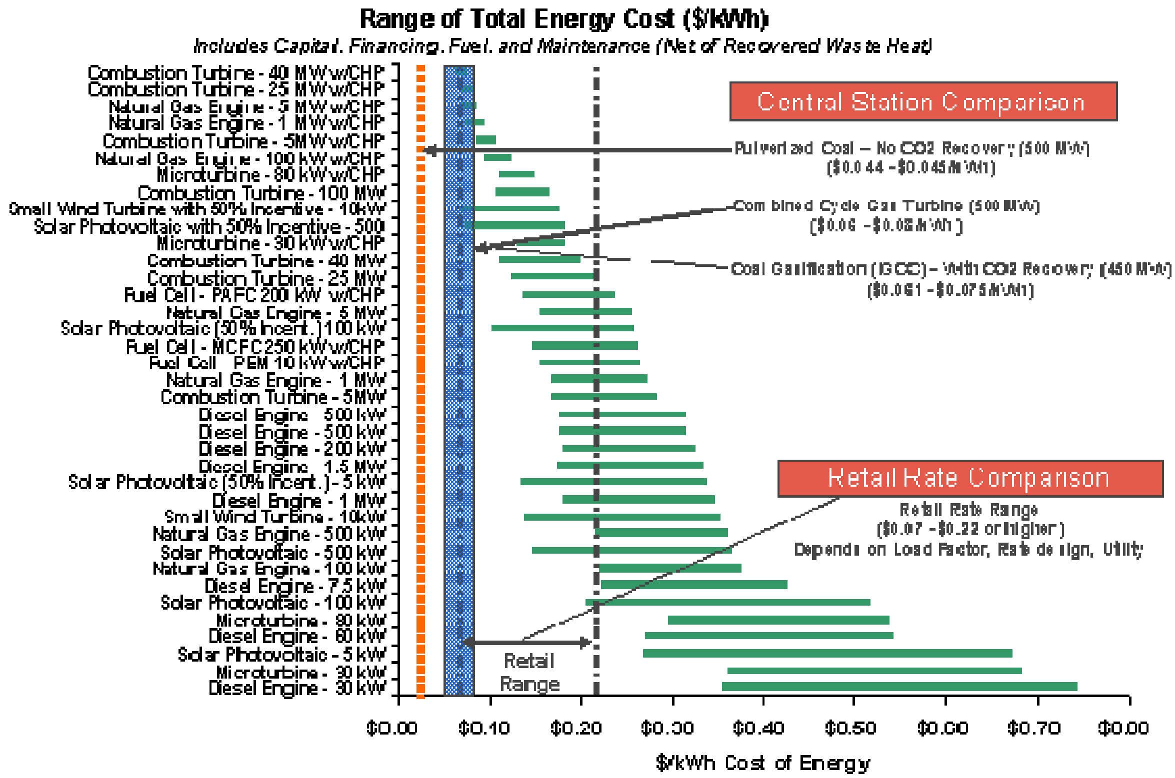


Figure 3-1
Range of operating costs for each technology, in levelized $/kWh, compared with ranges of central station generation and retail rates.

3.2 Detailed Costs and Benefits for Three Different Examples

Table A-1, Table A-2, and Table A-3 show the base case economic results for three example DER applications; a 1-MW combined heat and power application (same example as used previously), a 500-kW natural gas engine for peaking (same example as used previously), and a 500-kW photovoltaic installation, respectively. Each table shows each application's per kWh levelized cost and benefit and the overall net benefit from each perspective: customer-side DER, utility-side DER, and joint DER. For completeness and clarity, the input assumptions for each technology are provided on the right hand side of the table. Figure 3-2, Figure 3-3and Figure 3-4 each provide a graphical display of the relative cost and benefit components shown in the tables preceding each figure. In this format, the relative impact of each component on the overall resulting cost-effectiveness can easily be discerned.

Table A-1
Base Case Results and Assumptions for 1MW with CHP

Base Case Results for Natural Gas Engine - 1 MW w/CHP

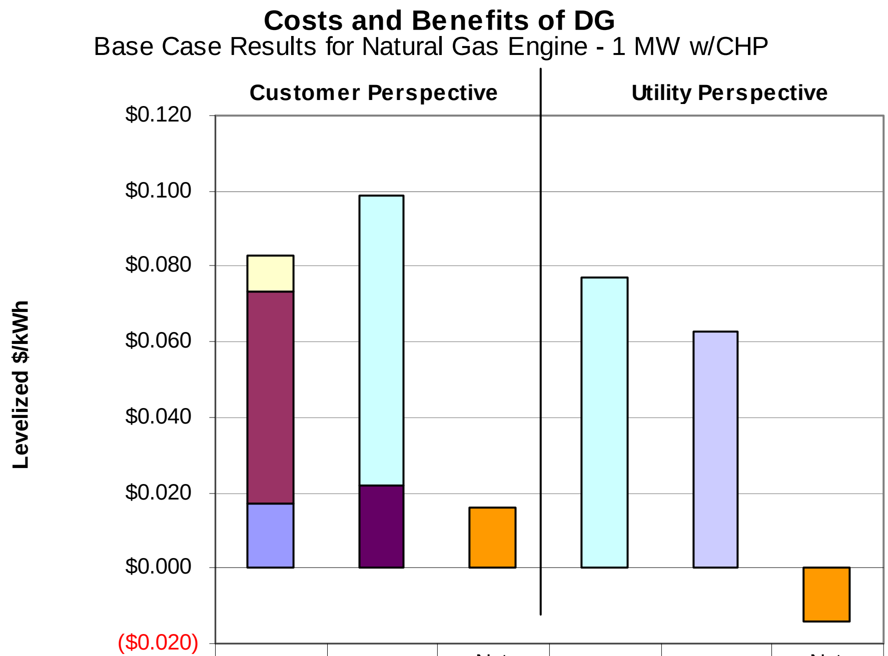
Customer DER Application		**8000 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.017	$139
Fuel Cost	$0.056	$447
Maintenance Cost	$0.010	$76
Total Cost	$0.083	$661
DER Benefits	Benefit per kWh	Benefit per kW
Utility Avoidable Rate	$0.077	$616
Value of Waste Heat	$0.022	$176
Backup Value	$0.000	$ -
Total Benefit	$0.099	$792
DG Owner Net Benefit	**$0.016**	**$130**
DG Customer B/C Ratio	*1.20*	
Utility DER Application (Economic Dispatch)		**2813 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.035	$98
Fuel Cost	$0.056	$157
Maintenance Cost	$0.010	$29
Total Cost	$0.101	$284
DER Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.087	$245
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Total Benefit	$0.087	$245
Utility Net Benefit	**($0.014)**	**($40)**
Utility B/C Ratio	*0.86*	
Joint Customer and Utility Application		
Utility DER Costs	Cost per kWh	Cost per kW
Customer Incentive / Utility Cost	$0.000	$0
Utility Revenue Loss	$0.077	$616
Utility Cost	$0.077	$616
Utility Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.063	$504
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Utility Benefit	$0.063	$504
Utility Net Benefit	**($0.014)**	**($112)**
DG Utility B/C Ratio	*0.82*	
DG Owner Net Benefit (with Incentive)	**$0.016**	**$130**
DG Customer B/C Ratio	*1.20*	

Base Case Input Assumptions		
DG Cost and Performance		
Installed Cost $/kW	$	950
Fixed O&M $/kW-year	$	4.00
Customer Carrying Charge		15%
Heat rate Btu/kWh		10,040
Variable O&M $/kWh	$	0.0090
Operating Hours (hours / year)		8,000
Capacity Factor		91.32%
Delivered Fuel Cost $/MMBtu	$	5.56
Application Type (Note 1)		2
Avoided Utility Bills		
Total Average Rate $/kWh	$	0.12
Avg. Class Load Factor		40%
Energy Rate $/kWh	$	0.05
Demand Charge $/kW-mo	$	20.00
Standby Reservation Charge $/kW-mo	$	3.00
Rate Type (Note 2)		3
Avoided Utility Bill $/kWh	$	0.08
Waste Heat Recovery		
Percent of Heat Recovery (%)		31%
Efficiency of Replaced Use (e.g. boiler)		80%
Recovered Fuel (Btu/kWh)		3,947
Value of Displaced Fuel $/MMBtu	$	5.56
Value per kWh of DER Generation	$	0.02
Backup Value		
Value per Year of Backup ($)	$	50,000
Size of Required DG system (kW)		500
Value per kW of DG system ($/kW)	$	-
Utility DER Economics		
Utility Carrying Charge		10%
Annual Average Market Price ($/kWh)	$	0.0546
Average Marginal Losses		8%
Economic Operating Hours (hours / year)		2814
Average Revenue (from Market Price Curve)	$	0.0870
Wholesale Capacity Value ($/kW-yr)	$	-
System Peak Marginal Losses (%)		11%
T&D Capacity Value	$	-
T&D Peak Marginal Losses		10%
Joint DER Economics		
Avoided Energy Costs $/kWh	$	0.0630
Customer Incentive $/kW	$	-
Customer Incentive $/kWh	$	-

Notes

1. Application Types
Application 1: Peaking/Back-up
Application 2: CHP/Baseload
Application 3: Renewable

2. Rate Types
Rate 1: Energy Charge Only
Rate 2: Energy and $20/kW-mo Demand Charge
Rate 3: Rate 2 with $3/kW-mo Reservation Charge
Rate 4: Rate 2 with Annual Ratchet



	Costs	Benefits	Net Benefit	Costs	Benefits	Net Benefit
Maintenance Cost	$0.010					
Fuel Cost	$0.056					
Financing and Capital	$0.017					
Utility Avoidable Rate		$0.077		$0.077		
Backup Value		$0.000				
Waste Heat		$0.022				
T&D Capacity					$0.000	
Wholesale Capacity					$0.000	
Wholesale Energy					$0.063	
Net Benefit			$0.016			($0.014)

Figure 3-2
MW Natural Gas Engine with CHP: Breakdown of Costs and Benefits by Component

Table A-2
Base Case Assumptions for 500kW Natural Gas Engine

Base Case Results for Natural Gas Engine - 500 kW

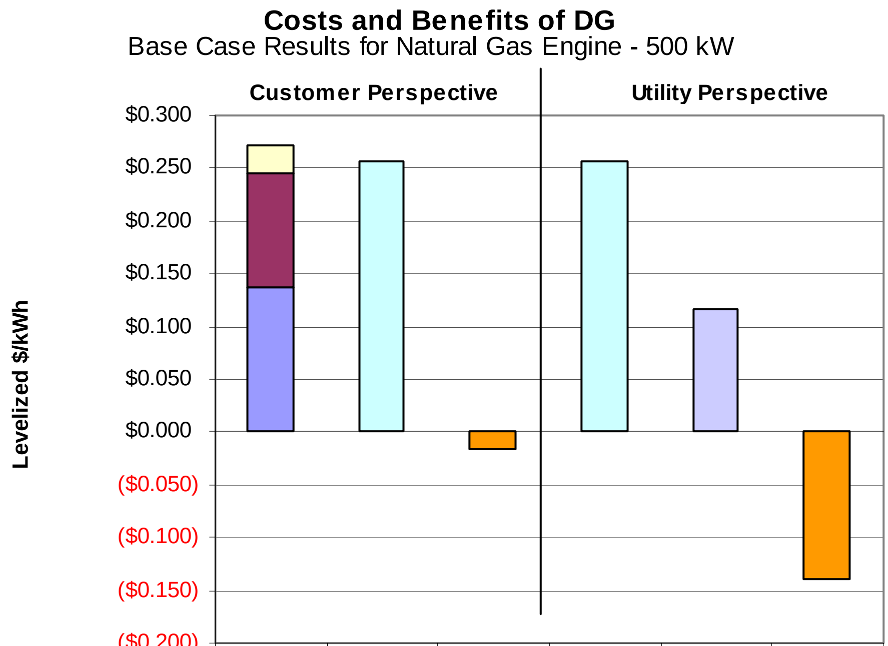
Customer DER Application		**1000 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.136	$136
Fuel Cost	$0.109	$109
Maintenance Cost	$0.027	$27
Total Cost	$0.273	$273
DER Benefits	Benefit per kWh	Benefit per kW
Utility Avoidable Rate	$0.256	$256
Value of Waste Heat	$0.000	$0
Backup Value	$0.000	$ -
Total Benefit	$0.256	$256
DG Owner Net Benefit	**($0.017)**	**($17)**
DG Customer B/C Ratio	*0.94*	
Utility DER Application (Economic Dispatch)		**381 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.253	$96
Fuel Cost	$0.109	$42
Maintenance Cost	$0.070	$27
Total Cost	$0.432	$165
DER Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.157	$60
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Total Benefit	$0.157	$60
Utility Net Benefit	**($0.275)**	**($105)**
Utility B/C Ratio	*0.36*	
Joint Customer and Utility Application		
Utility DER Costs	Cost per kWh	Cost per kW
Customer Incentive / Utility Cost	$0.000	$0
Utility Revenue Loss	$0.256	$256
Utility Cost	$0.256	$256
Utility Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.116	$116
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Utility Benefit	$0.116	$116
Utility Net Benefit	**($0.139)**	**($139)**
DG Utility B/C Ratio	*0.45*	
DG Owner Net Benefit (with Incentive)	**($0.017)**	**($17)**
DG Customer B/C Ratio	*0.94*	

Base Case Input Assumptions		
DG Cost and Performance		
Installed Cost $/kW	$	936
Fixed O&M $/kW-year	$	26.50
Customer Carrying Charge		15%
Heat rate Btu/kWh		12,003
Variable O&M $/kWh	$	0.0000
Operating Hours (hours / year)		1,000
Capacity Factor		11.42%
Delivered Fuel Cost $/MMBtu	$	9.12
Application Type (Note 1)		1
Avoided Utility Bills		
Total Average Rate $/kWh	$	0.12
Avg. Class Load Factor		40%
Energy Rate $/kWh	$	0.05
Demand Charge $/kW-mo	$	20.00
Standby Reservation Charge $/kW-mo	$	3.00
Rate Type (Note 2)		3
Avoided Utility Bill $/kWh	$	0.26
Waste Heat Recovery		
Percent of Heat Recovery (%)		0%
Efficiency of Replaced Use (e.g. boiler)		80%
Recovered Fuel (Btu/kWh)		-
Value of Displaced Fuel $/MMBtu	$	9.12
Value per kWh of DER Generation	$	-
Backup Value		
Value per Year of Backup ($)	$	50,000
Size of Required DG system (kW)		500
Value per kW of DG system ($/kW)	$	-
Utility DER Economics		
Utility Carrying Charge		10%
Annual Average Market Price ($/kWh)	$	0.0546
Average Marginal Losses		8%
Economic Operating Hours (hours / year)		381
Average Revenue (from Market Price Curve)	$	0.1569
Wholesale Capacity Value ($/kW-yr)	$	-
System Peak Marginal Losses (%)		11%
T&D Capacity Value	$	-
T&D Peak Marginal Losses		10%
Joint DER Economics		
Avoided Energy Costs $/kWh	$	0.1162
Customer Incentive $/kW	$	-
Customer Incentive $/kWh	$	-

Notes

1. Application Types
Application 1: Peaking/Back-up
Application 2: CHP/Baseload
Application 3: Renewable

2. Rate Types
Rate 1: Energy Charge Only
Rate 2: Energy and $20/kW-mo Demand Charge
Rate 3: Rate 2 with $3/kW-mo Reservation Charge
Rate 4: Rate 2 with Annual Ratchet



	Costs	Benefits	Net Benefit	Costs	Benefits	Net Benefit
Maintenance Cost	$0.027					
Fuel Cost	$0.109					
Financing and Capital	$0.136					
Utility Avoidable Rate		$0.256		$0.256		
Backup Value		$0.000				
Waste Heat		$0.000				
T&D Capacity					$0.000	
Wholesale Capacity					$0.000	
Wholesale Energy					$0.116	
Net Benefit			($0.017)			($0.139)

Figure 3-3
500 kW Natural Gas Engine: Breakdown of Costs and Benefits by Component

Table A-3
Base Case Assumptions for 500 kW Solar PV

Base Case Results for Solar Photovoltaic - 500 kW

Customer DER Application		**3000 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.230	$691
Fuel Cost	$0.000	$0
Maintenance Cost	$0.001	$3
Total Cost	$0.231	$694
DER Benefits	Benefit per kWh	Benefit per kW
Utility Avoidable Rate	$0.120	$359
Value of Waste Heat	$0.000	$0
Backup Value	$0.000	$ -
Total Benefit	$0.120	$359
DG Owner Net Benefit	**($0.112)**	**($336)**
DG Customer B/C Ratio	*0.52*	

Utility DER Application (Economic Dispatch)		**3000 hours**
DER Costs	Cost per kWh	Cost per kW
Financing and Capital	$0.163	$488
Fuel Cost	$0.000	$0
Maintenance Cost	$0.001	$3
Total Cost	$0.164	$491
DER Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.059	$177
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Total Benefit	$0.059	$177
Utility Net Benefit	**($0.105)**	**($314)**
Utility B/C Ratio	*0.36*	

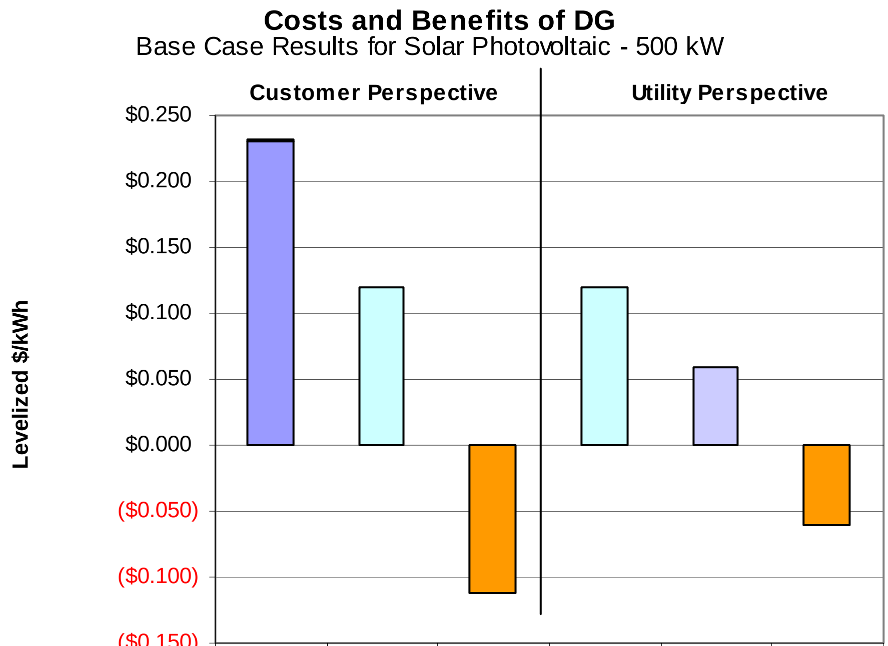
Joint Customer and Utility Application		
Utility DER Costs	Cost per kWh	Cost per kW
Customer Incentive / Utility Cost	$0.000	$0
Utility Revenue Loss	$0.120	$359
Utility Cost	$0.120	$359
Utility Benefits	Benefits per kWh	Benefits per kW
Wholesale Energy	$0.059	$177
Wholesale Capacity	$0.000	$0
T&D Capacity	$0.000	$0
Utility Benefit	$0.059	$177
Utility Net Benefit	**($0.060)**	**($181)**
DG Utility B/C Ratio	*0.49*	
DG Owner Net Benefit (with Incentive)	**($0.112)**	**($336)**
DG Customer B/C Ratio	*0.52*	

Base Case Input Assumptions		
DG Cost and Performance		
Installed Cost $/kW	$	4,740
Fixed O&M $/kW-year	$	2.85
Customer Carrying Charge		15%
Heat rate Btu/kWh		-
Variable O&M $/kWh	$	-
Operating Hours (hours / year)		3,000
Capacity Factor		34.25%
Delivered Fuel Cost $/MMBtu	$	-
Application Type (Note 1)		3
Avoided Utility Bills		
Total Average Rate $/kWh	$	0.12
Avg. Class Load Factor		40%
Energy Rate $/kWh	$	0.05
Demand Charge $/kW-mo	$	20.00
Standby Reservation Charge $/kW-mo	$	3.00
Rate Type (Note 2)		3
Avoided Utility Bill $/kWh	$	0.12
Waste Heat Recovery		
Percent of Heat Recovery (%)		0%
Efficiency of Replaced Use (e.g. boiler)		80%
Recovered Fuel (Btu/kWh)		-
Value of Displaced Fuel $/MMBtu	$	-
Value per kWh of DER Generation	$	-
Backup Value		
Value per Year of Backup ($)	$	50,000
Size of Required DG system (kW)		500
Value per kW of DG system ($/kW)	$	-
Utility DER Economics		
Utility Carrying Charge		10%
Annual Average Market Price ($/kWh)	$	0.0546
Average Marginal Losses		8%
Economic Operating Hours (hours / year)		3000
Average Revenue (from Market Price Curve)	$	0.0590
Wholesale Capacity Value ($/kW-yr)	$	-
System Peak Marginal Losses (%)		11%
T&D Capacity Value	$	-
T&D Peak Marginal Losses		10%
Joint DER Economics		
Avoided Energy Costs $/kWh	$	0.0590
Customer Incentive $/kW	$	-
Customer Incentive $/kWh	$	-

Notes

1. Application Types
Application 1: Peaking/Back-up
Application 2: CHP/Baseload
Application 3: Renewable

2. Rate Types
Rate 1: Energy Charge Only
Rate 2: Energy and $20/kW-mo Demand Charge
Rate 3: Rate 2 with $3/kW-mo Reservation Charge
Rate 4: Rate 2 with Annual Ratchet



	Customer Perspective: Costs	Customer Perspective: Benefits	Customer Perspective: Net Benefit	Utility Perspective: Costs	Utility Perspective: Benefits	Utility Perspective: Net Benefit
Maintenance Cost	$0.001					
Fuel Cost	$0.000					
Financing and Capital	$0.230					
Utility Avoidable Rate		$0.120		$0.120		
Backup Value		$0.000				
Waste Heat		$0.000				
T&D Capacity					$0.000	
Wholesale Capacity					$0.000	
Wholesale Energy					$0.059	
Net Benefit			($0.112)			($0.060)

Figure 3-4
500 kW Solar PV: Breakdown of Costs and Benefits by Component

3.3 Range of Net Benefits for Each Technology, Customer and Utility Perspectives

Repeating the analysis for each DER technology under the base case, ‘optimistic’, and ‘pessimistic’ input assumptions produces the range of net benefits from both the customer and utility perspectives. The resulting ranges by these two perspectives indicate if the technology has joint application potential.

A summary of the results of this analysis is provided in the following pages. Figure 3-5 shows the net benefits from the customer perspective sorted from greatest to least net benefits and categorized by application type; peaking/back-up, combined heat and power (CHP)/baseload, and renewable applications. The error bars around the central point indicate the optimistic and pessimistic scenarios around the base case cost and benefit assumptions. Figure 3-6 shows only the net benefits for peaking applications for the utility-side perspective because these are the most likely utility application for DER. The red horizontal axis shows the ‘zero’ or ‘break-even’ line in each case.

Figure 3-7 shows both the customer-side and utility-side perspectives and is also categorized by application type. Figure 3-8, Figure 3-9, and Figure 3-10 (following pages) show the same results, but only depict one application type per figure. In each figure, the customer perspective is shown in green with a diamond-shaped marker indicating the base case results, and utility perspective results are shown in orange with a square marker indicating the base case. Error bars extend to the ‘optimistic’ and ‘pessimistic’ ranges.

3.3.1 Peak Shaving Results

The most cost-effective peak shaving results come from diesel reciprocating engines (top six technologies), then big natural gas turbines in descending size (40-MW, 25-MW), and then big natural gas reciprocating engines (5-MW then 1-MW). All of these technologies are either diesel which are difficult to permit because of air quality restrictions, or very large for most customers. The 500-kW and 100-kW natural gas reciprocating engines are, however, still cost-effective and may be an option for large, low load factor customers. All of these applications result in greater revenue loss to the utility than the savings of energy, transmission and distribution, or losses.

3.3.2 Baseload / CHP Results

The cost-effectiveness of baseload / combined heat and power (CHP) technologies declines with size. Of those technologies sized at 1-MW or less, the natural gas reciprocating engine and turbine are cost-effective in the base case. These might be options for customers who utilize significant waste-heat, and have a need for baseload electricity. Microturbines were cost-effective to the customer only in the optimistic case, and fuel cells were not cost-effective in any scenario. All of these applications are not cost-effective to a utility because the revenue loss exceeds the total savings in energy, transmission and distribution, or losses.

3.3.3 Renewable Results

The renewable results are shown with and without a 50% incentive on the capital cost of the technology. Even with the incentive, only the very largest photovoltaic installation (500-kW) is cost-effective. Absent the 50% incentive, none of the renewable technologies were cost-effective in the base case analysis.

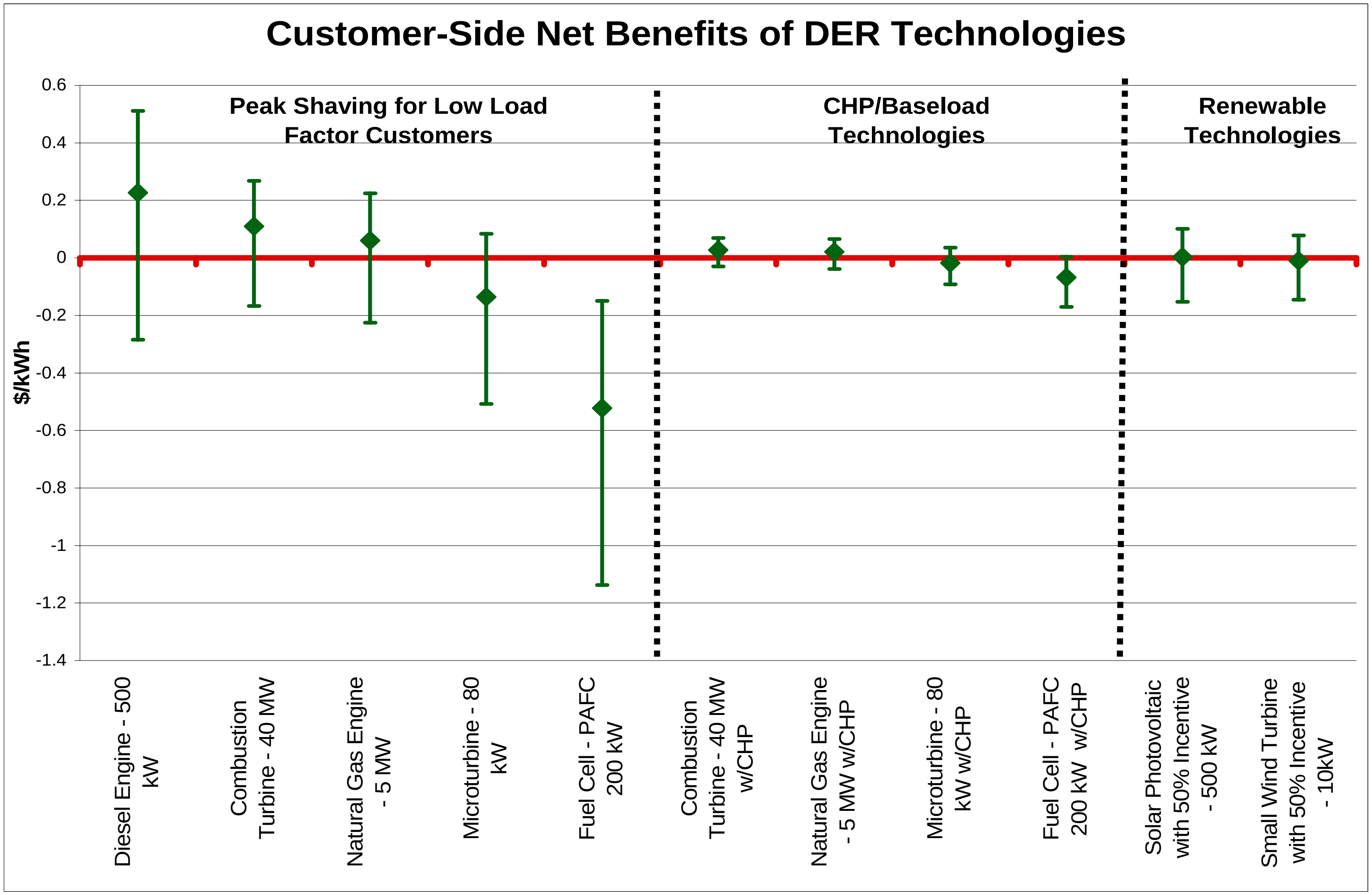


Figure 3-5
Customer-side Net Benefits of DER Technologies. The technology with greatest net benefit for each type of technology is shown. Values are sorted within DER application category. Error bars represent the sensitivity range tested around the base case scenario.

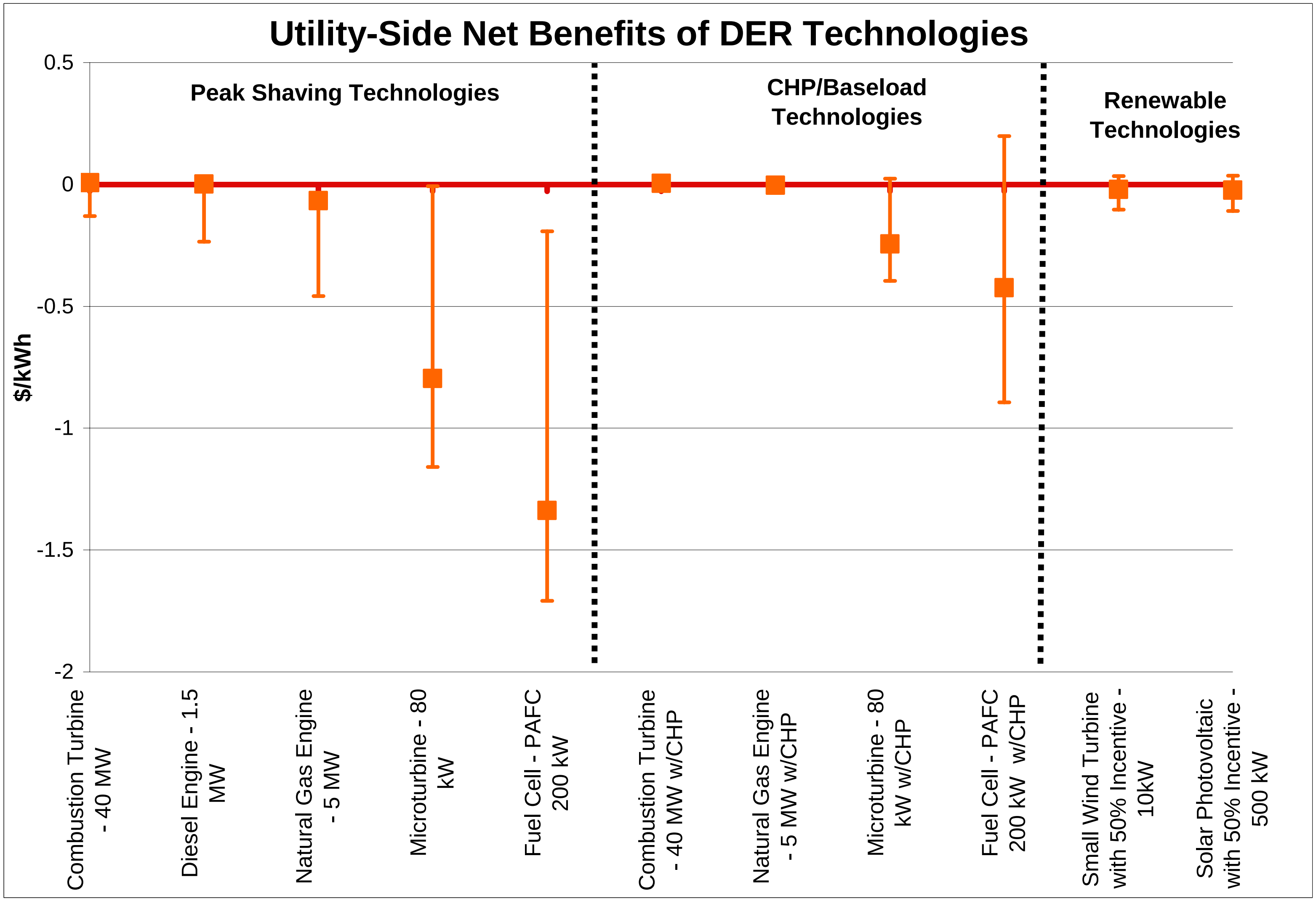


Figure 3-6
Utility-side Net Benefits of DER Technologies. The technology with greatest net benefit for each type of technology is shown. Values are sorted within DER application category. Error bars represent the sensitivity range tested around the base case scenario.

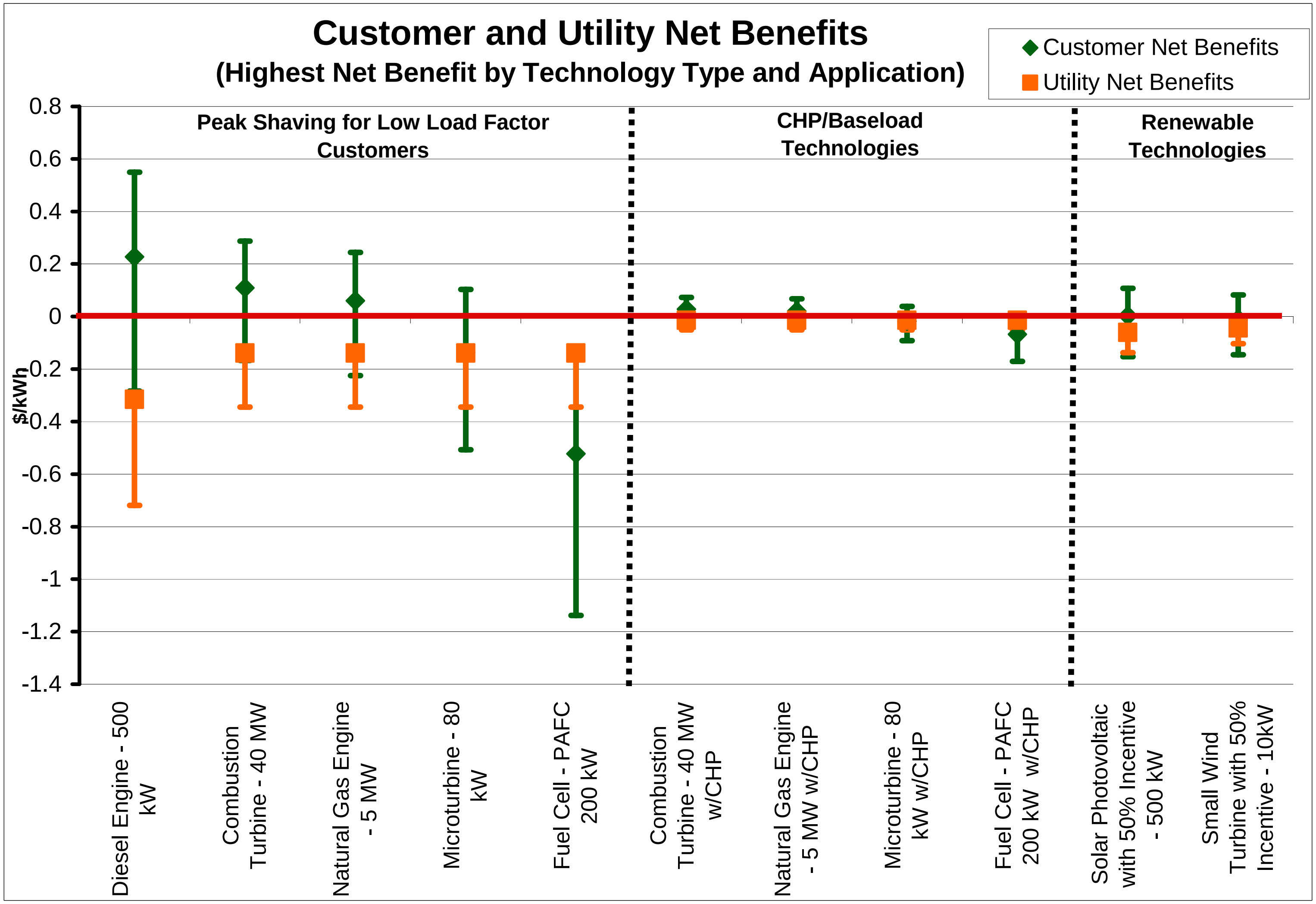


Figure 3-7
Joint Customer-Utility net benefits of DER technologies. The technology with greatest net benefit for each type of technology is shown. Values are sorted from the customer-side perspective within DER application category. Error bars represent the sensitivity range tested around the base case scenario. Technologies with overlapping error bars or net benefits that are greater than zero could potentially be a cost-effective DER application.

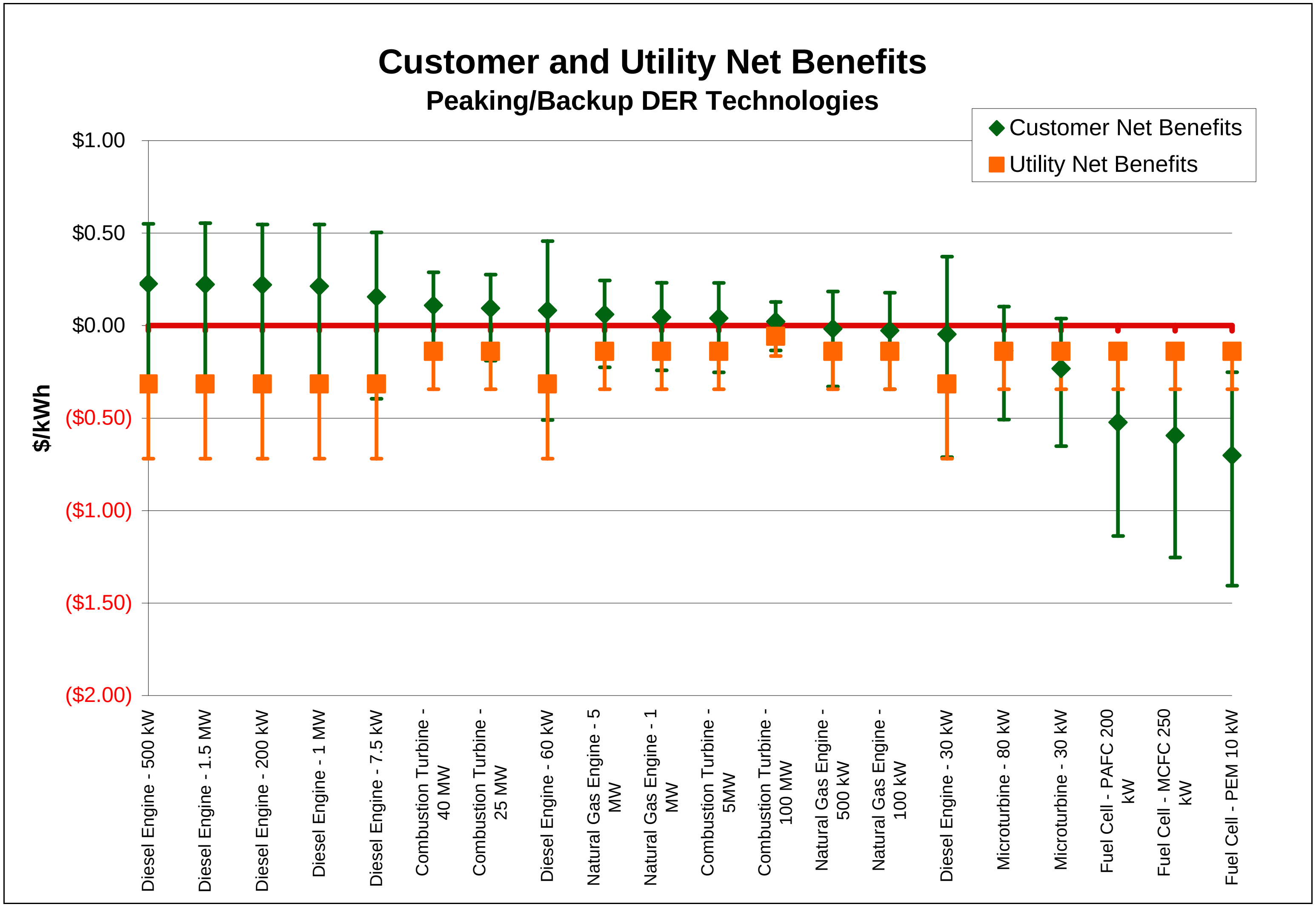


Figure 3-8
Joint Customer-Utility Perspective for Peaking/Backup DER Application

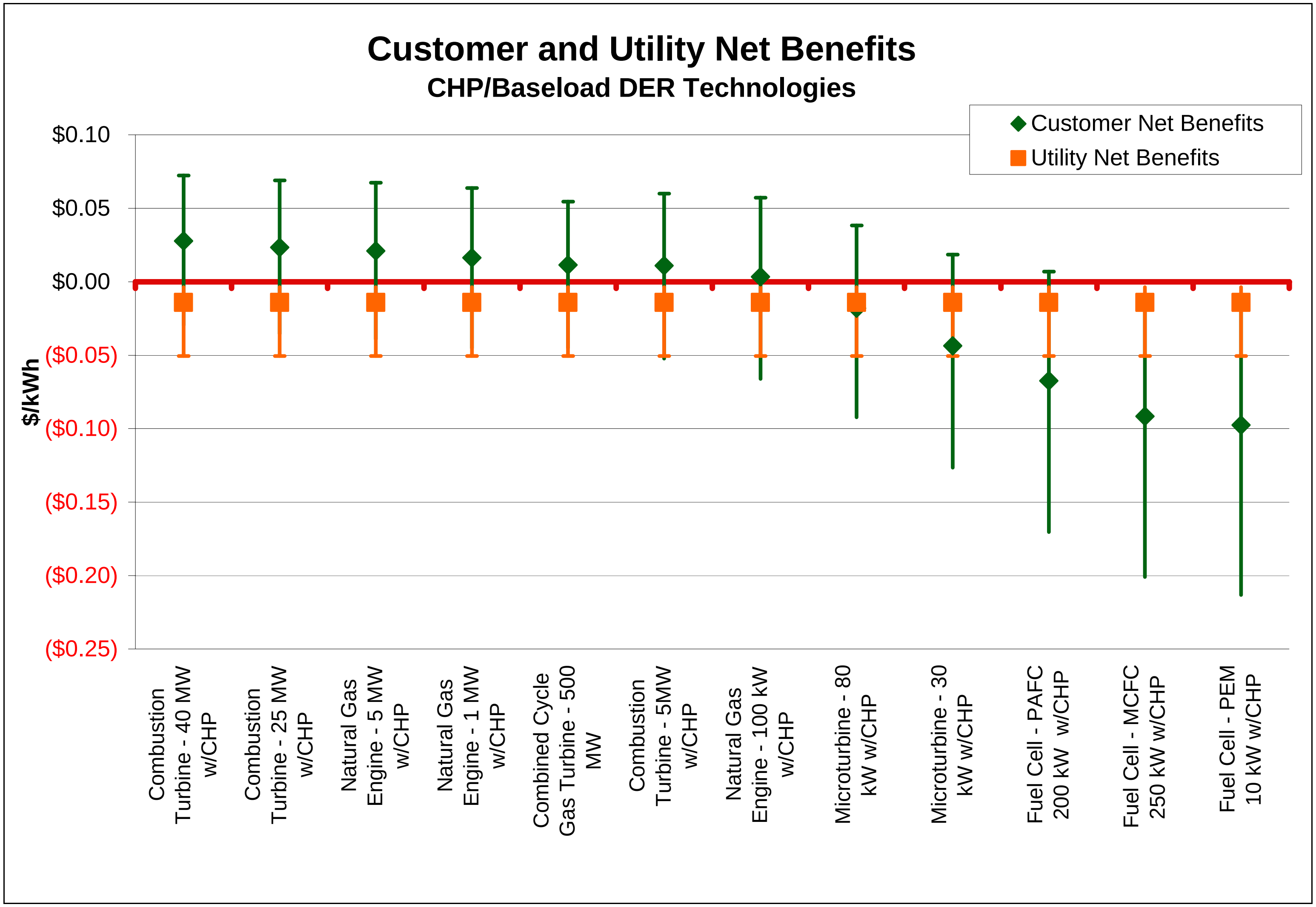


Figure 3-9
Joint Customer-Utility Perspective for CHP/Baseload DER Applications

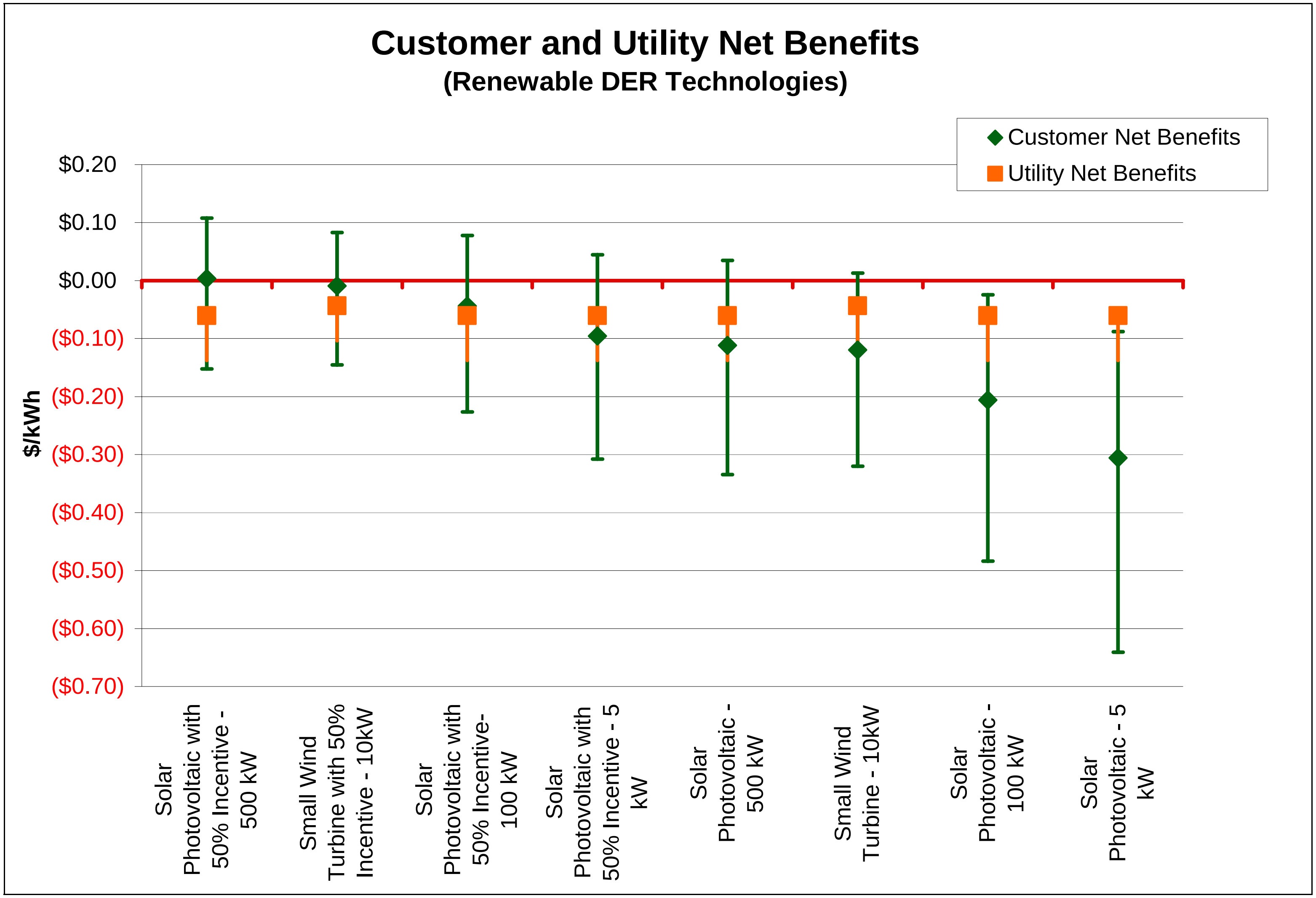


Figure 3-10
Joint Customer-Utility Perspective for Renewable DER Application

4
KEY FINDINGS AND RECOMMENDATIONS

One of the most salient findings of this cost and benefit analysis is that the utility net benefit is negative for most cost-effective customer DER applications. The current DER landscape indicates that the two most widespread applications of DER are 1) combined heat and power with waste gas usage and 2) back-up power applications. These applications tend to be customer-driven due to the favorable economics for the DER owner. Only those DER applications that have positive net benefits from a societal perspective (TRC test) have enough value to be potentially cost-effective from both the customer and utility perspectives.

From the utility perspective most DER applications under the existing regulations and rate structures tend to either 1) drive up rates for all customers or 2) reduce utility shareholder value. This disparity between cost-effective customer applications and cost in-effective utility applications is what must be addressed if DER is to capture the potential benefits touted by supporters on a widespread scale.

Potential ways to address this disparity involve a combination of several actions including:

1. Reducing DER capital costs
2. Increasing DER operating efficiency
3. Better deployment of DER resources to capture additional value streams

While reducing capital costs and increasing efficiency of DER technologies is ongoing within the DER industry, better deployment of these resources can be pursued concurrently. Given the installed base of DER today, it is clear that DER vendors have been able to effectively target the DER to meet the customer's needs for combined heat and power or back-up power. However, the lack of DER sited as utility resources indicates that there is an opportunity to capture more value for utilities using DER.

There are several potential future areas of study to address the issue of DER's ability to provide value to utility customers, which include but are not limited to the following:

1. Siting DER in the best location on the electrical system within utility planning process
2. Allowing DER to participate in multiple markets for utility services
    (a) Near term opportunities: capacity markets, resource adequacy, emission credit markets
3. Establishing DER as a potential resource for improving islanding and reliability on utility system

4. Developing regulatory and rate structures that facilitate DER siting and use by utilities as:

    (a) A part of the T&D system

    (b) A utility resource (generation, capacity, resource adequacy, and emissions)

A
DER TECHNOLOGY COST AND PERFORMANCE ASSUMPTIONS

Table A-1 displays the cost and performance assumptions we used to compute the cost-effectiveness results in this analysis. Each column lists the base case assumptions and the scenario definitions are shown at the bottom of the column. For example, in the installed cost column, the capital costs plus installation costs are shown on a $/kW basis. To evaluate a high cost scenario this base case is increased to 120%, whereas in a low cost scenario is reduced to 83% of the base case.

The columns in this table show the following information:

Column 1: Application Type: 1 = peaking, 2= baseload, 3 = renewable
Column 2: DER Application name
Column 3: Heat Rate, or the operational efficiency of the DER technology on a Btu/kWh basis.
Column 4: Fixed O&M, or operations and maintenance required annually on $/kW-year basis
Column 5: Variable O&M, or operations and maintenance costs required dependent upon the output of the DER technology on a $/kWh basis
Column 6: Operating hours, or the expected number of hours the technology will operate per year
Column 7: Fuel Type Index, where 1 = core commercial gas, 2 = industrial gas, 3 = EG/Cogen, 4 = diesel, and 5 = renewable
Column 8: Lifetime, or the number of years the DER technology is operational
Column 9: Waste heat recovery, where yes = a portion of the waste heat from operations is recovered, no = none of the waste heat is recovered
Column 10: Maximum heat recovery, the maximum % of waste heat that is recovered if Column 9 is “yes”
Column 11: Base case back-up, the value placed on the DER technology for back-up reliability purposes. No is shown in all cases because back-up value is only considered in the optimistic case.

Table A-1
DER Cost and Operating Assumptions

Application Type	Technology	Total Installed Cost $/kW	Heat Rate Btu/kWh	Fixed O&M $/kW-yr	Variable O&M $/kWh	Operating Hours/ Year	Fuel Type (Index)	Lifetime (not used)	Waste Heat Recovery	Maximum Heat Recovery	Base Case Backup?	Customer Backup Value ($/kW)
	Base Case Assumptions	36	**DG Technologies**									
2	Combined Cycle Gas Turbine - 500 MW	$ 610	7,100	$ 90	$ 0.004	8000	3	20	yes	0%	no	$ -
1	Combustion Turbine - 5MW	$ 779	12,590	$ 10	$ 0.005	1000	2	20	no	0%	no	$ -
2	Combustion Turbine - 5MW w/CHP	$ 1,024	12,590	$ 10	$ 0.006	8000	3	20	yes	40%	no	$ -
1	Combustion Turbine - 25 MW	$ 660	9,950	$ 6	$ 0.004	1000	3	20	no	0%	no	$ -
2	Combustion Turbine - 25 MW w/CHP	$ 800	9,950	$ 6	$ 0.004	8000	3	20	yes	36%	no	$ -
1	Combustion Turbine - 40 MW	$ 590	9,220	$ 5	$ 0.004	1000	3	20	no	0%	no	$ -
2	Combustion Turbine - 40 MW w/CHP	$ 700	9,220	$ 5	$ 0.004	8000	3	20	yes	35%	no	$ -
1	Combustion Turbine - 100 MW	$ 480	9,300	$ 78	$ 0.006	2000	3	20	no	0%	no	$ -
1	Fuel Cell - PEM 10 kW	$ 5,500	11,370	$ 18	$ 0.033	1000	1	10	no	0%	no	$ -
2	Fuel Cell - PEM 10 kW w/CHP	$ 5,500	11,370	$ 18	$ 0.033	8000	3	10	yes	36%	no	$ -
1	Fuel Cell - PAFC 200 kW	$ 4,500	9,480	$ 7	$ 0.029	1000	1	10	no	0%	no	$ -
2	Fuel Cell - PAFC 200 kW w/CHP	$ 4,500	9,480	$ 7	$ 0.029	8000	3	10	yes	36%	no	$ -
1	Fuel Cell - MCFC 250 kW	$ 5,000	7,930	$ 5	$ 0.043	1000	1	10	no	0%	no	$ -
2	Fuel Cell - MCFC 250 kW w/CHP	$ 5,000	7,930	$ 5	$ 0.043	8000	3	10	yes	22%	no	$ -
1	Microturbine - 30 kW	$ 2,260	15,070	$ -	$ 0.020	1000	1	10	no	0%	no	$ -
2	Microturbine - 30 kW w/CHP	$ 2,630	15,070	$ -	$ 0.020	8000	3	10	yes	35%	no	$ -
1	Microturbine - 80 kW	$ 1,710	14,100	$ -	$ 0.013	1000	1	10	no	0%	no	$ -
2	Microturbine - 80 kW w/CHP	$ 1,930	14,100	$ -	$ 0.013	8000	3	10	yes	38%	no	$ -
1	Diesel Engine - 30 kW	$ 1,290	11,887	$ 27	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Diesel Engine - 60 kW	$ 864	11,201	$ 27	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Diesel Engine - 500 kW	$ 386	10,314	$ 27	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Diesel Engine - 7.5 kW	$ 627	10,458	$ 27	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Diesel Engine - 200 kW	$ 416	9,944	$ 27	$ 0.000	500	4	10	no	0%	no	$ -
1	Diesel Engine - 1 MW	$ 570	9,870	$ 8	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Diesel Engine - 1.5 MW	$ 550	9,490	$ 8	$ 0.000	500	4	12.5	no	0%	no	$ -
1	Natural Gas Engine - 100 kW	$ 1,030	11,500	$ 10	$ 0.017	1000	1	10	no	0%	no	$ -
2	Natural Gas Engine - 100 kW w/CHP	$ 1,350	11,500	$ 10	$ 0.017	8000	3	10	yes	49%	no	$ -
1	Natural Gas Engine - 500 kW	$ 936	12,003	$ 27	$ 0.000	1000	1	10	no	0%	no	$ -
1	Natural Gas Engine - 1 MW	$ 720	10,040	$ 4	$ 0.009	1000	1	10	no	0%	no	$ -
2	Natural Gas Engine - 1 MW w/CHP	$ 950	10,040	$ 4	$ 0.009	8000	3	10	yes	37%	no	$ -
1	Natural Gas Engine - 5 MW	$ 700	9,210	$ 1	$ 0.008	1000	1	10	no	0%	no	$ -
2	Natural Gas Engine - 5 MW w/CHP	$ 890	9,210	$ 1	$ 0.008	8000	3	10	yes	36%	no	$ -
3	Solar Photovoltaic - 5 kW	$ 8,650	-	$ 14	$ -	3000	5	20	no	0%	never	$ -
3	Solar Photovoltaic - 100 kW	$ 6,675	-	$ 3	$ -	3000	5	20	no	0%	never	$ -
3	Solar Photovoltaic - 500 kW	$ 4,740	-	$ 3	$ -	3000	5	20	no	0%	never	$ -
3	Small Wind Turbine - 10kW	$ 6,055	-	$ 6	$ -	4000	5	10	no	0%	never	$ -
Scenario Definitions												
	Optimistic	83%	83%	83%	83%	110%		100%	Base Case	85%	yes	83%
	Pessimistic	120%	120%	120%	120%	91%		100%	Pessimistic	70%	no	120%

Application Types
Application 1: Peaking/Back-up
Application 2: CHP/Baseload
Application 3: Renewable

Fuel Type Definitions
1=core commercial gas
2=industrial gas
3=EG/cogen
4=diesel
5=renewable

b

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