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Authors
Siddiqui, Afzal S.
Marnay, Chris
Bailey, Owen
et al.

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Afzal S. Siddiqui
University College Dublin

Chris Marnay, Owen Bailey, Kristina Hamachi LaCommare
Environmental Energy
Technologies Division

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OPTIMAL SELECTION OF ON-SITE GENERATION WITH COMBINED HEAT AND POWER APPLICATIONS

Afzal S Siddiqui[1], Chris Marnay[2], Owen Bailey[2], and Kristina Hamachi LaCommare[2]

[1]Department of Banking and Finance
University College Dublin
Blackrock, Co. Dublin, Republic of Ireland
Phone (+353) 1/716-8091, Fax (+353) 1/283-5482
E-mail: afzal.siddiqui@ucd.ie

[2]Environmental Energy
Technologies Division
Berkeley National Laboratory
Berkeley, CA 94720, USA
Phone (+510) 486-7028, Fax (+510) 486-7976

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ABSTRACT

While demand for electricity continues to grow, expansion of the traditional electricity supply system, or *macrogrid*, is constrained and is unlikely to keep pace with the growing thirst western economies have for electricity. Furthermore, no compelling case has been made that perpetual improvement in the overall power quality and reliability (PQR) delivered is technically possible or economically desirable. An alternative path to providing high PQR for sensitive loads would generate close to them in *microgrids*, such as the Consortium for Electricity Reliability Technology Solutions (CERTS) Microgrid. Distributed generation would alleviate the pressure for endless improvement in macrogrid PQR and might allow the establishment of a sounder economically based level of universal grid service. Energy conversion from available fuels to electricity close to loads can also provide combined heat and power (CHP) opportunities that can significantly improve the economics of small-scale on-site power generation, especially in hot climates when the waste heat serves absorption cycle cooling equipment that displaces expensive on-peak electricity. An optimisation model, the Distributed Energy Resources Customer Adoption Model (DER-CAM), developed at Berkeley Lab identifies the energy bill minimising combination of on-site generation and heat recovery equipment for sites, given their electricity and heat requirements, the tariffs they face, and a menu of available equipment. DER-CAM is used to conduct a systemic energy analysis of a southern California naval base building and demonstrates a typical current economic on-site power opportunity. Results achieve cost reductions of about 15% with DER, depending on the tariff. Furthermore, almost all of the energy is provided on-site, indicating that modest cost savings can be achieved when the microgrid is free to select distributed generation and heat recovery equipment in order to minimise its overall costs.

1 INTRODUCTION

1.1 Summer 2003 Blackouts

At lunchtime on 14 August 2003, incorrect data were entered into system monitoring software at the Midwest Independent System Operator (MISO) headquarters in Carmel IN, rendering it ineffective.[1] The vast, sprawling, discontinuous 2.8e6 km^2 territory MISO controls, spanning states from North Dakota almost to the East Coast, was unwittingly jeopardised. Failure to respond effectively to the fairly routine events that followed during that afternoon degraded much of the MISO system to a point, around 3:45 pm, when the system was beyond recovery. Following loss of a large line just after 4:00 pm, major cascading failures over a major area of the northeast left about 50 million people in the US and Canada surviving in a darkened, dangerous, hobbled economy. Luckily, aside from the economic losses, the consequences of this blackout were not major, but the ill-conceived interdependency of critical systems became painfully apparent: mobile phone systems fell silent, and the Toronto subway stayed partially parked for three days. While such dramatic blackouts are rare, the northeast US blackout was soon coincidentally followed by large-scale outages in London, Scandinavia, and Italy, further underscoring the vulnerability of advanced economies to loss of power.[2]

While dependency on a highly reliable grid delivering clean power has intensified, smaller generation using a diverse mix of technologies, usually collectively called distributed energy resources (DER), has emerged as increasingly competitive with large remote central station generation. DER can provide power with reliability and quality (PQR) tailored to the requirements of the end uses served, i.e., heterogeneous PQR, in contrast to the universal homogeneous PQR provided by utility grids.

Many DER generate power directly, e.g., photovoltaic modules (PV), while others involve on-site energy conversion. Waste heat utilization by combined heat and power (CHP) technologies delivers one of the key economic and environmental advantages of small-scale generation involving conversion, e.g., from reciprocating engines, fuel cells, or microturbines. This heat can be productively applied to many end uses, but when used for cooling, using absorption cycles, it can be particularly valuable because it displaces high-priced electricity and simultaneously lowers the peak power requirement of the site, i.e., both saves expensive on-peak electricity and downsizes other system requirements.

A rich and growing literature explores the case for supplementing our existing power system by smaller scale localised generation closer to loads.[3,4,5,6] The purpose here is not to provide a comprehensive survey of DER benefits, rather just two issues are addressed: (1) the inability of our existing power system to provide for growing electricity use together with the inappropriateness of providing for the most demanding end uses by a universal standard PQR, and (2) the potential benefits provided by application of CHP systems in microgrids. The current state of the art for economic analysis of PQR requirements within facilities and more generally in the grid are rudimentary at best. Some directions for further research in this area are proposed, but no analysis is conducted. In contrast, analytic methods for the study of the second problem, namely optimal on-site CHP installation and operation, are quite well developed and a model using such techniques developed at Berkeley Lab is presented, the DER Customer Adoption Model (DER-CAM). DER-CAM is applied in an example analysis of a potential microgrid site at a naval base in southern California.

1.2 The Correct Macrogrid Level of Reliability

The August 2003 blackout underlined North America's dependence on its imperfect power grid(s). Analyses conducted in the aftermath have focused almost exclusively on ways to perfect the grid, presuming highly developed economies require flawless power at almost whatever cost. As our impressive and successful modern grids have evolved, the expectation that they can and should be uniformly close to perfect has led to a system of critically interdependent services vulnerable to grid failure. Heightened security concerns and the penetration of electronics into myriad aspects of everyday life are deepening this vulnerability. Very few methods exist for choosing economically optimal levels of reliability, so only some directions for further study are presented here, viz., division of the problem into two parts:

1. PQR levels for universal service on the utility grid; and
2. PQR local to end uses.

While the ideal is rarely achieved in practice, the prevailing paradigm is to provide a universal reliability to every node in the network. Figure 1.1 shows conceptually an approach to picking the optimum universal target reliability level to adopt. A similar argument could be made for power quality, but for simplicity here only the reliability dimension is discussed.

The x-axis shows increasing grid availability on a pseudo-log scale, with approximately the lowest reliability we can currently imagine as acceptable (90%) to the left and perfection (100%) to the right. The y-axis shows societal cost of providing reliability. Cost has two components, the cost of providing reliability and the cost of unreliability, i.e., of outages, with the sum representing total societal cost. The optimum is clearly at the point of minimum total social cost, which in this case occurs to the left of the current target. To repeat, this is purely a schematic and no actual data have been used here, nor indeed, are any data available to conduct such an analysis. In fact, the only value in this space that is generally considered of interest is the societal cost of outages, i.e., the gap between the current cost of outages and perfection at the x-axis, marked by the arrows in the figure. Recent estimates of this value for the US are in the 80 GUS$/a range.[7] In effect, society has chosen to push reliability as far to the right in Figure 1.1 as possible, with relatively little consideration of the tradeoffs implicitly involved. Furthermore, the push to the right has resulted in system interdependency with possibly unnecessarily costly consequences when failures occur. One might also consider the effect of making systems more resilient to power outage, and local provision of electricity by DER is one potential method. It is pure speculation at this point what the net effect would be, but one possibility is that the societal optimal could be pulled leftwards.

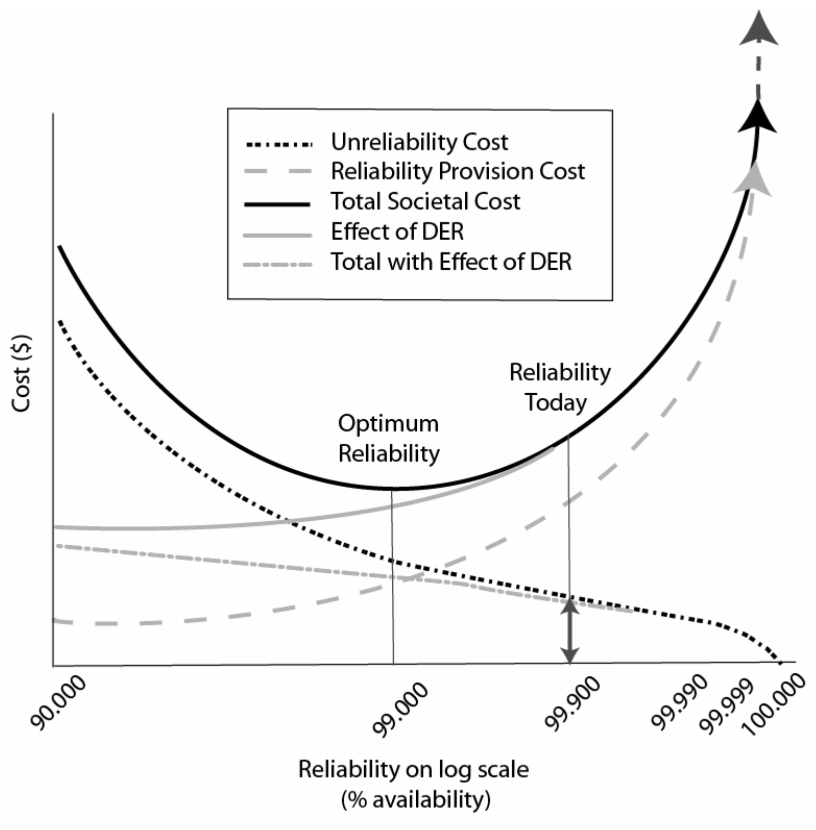

Figure 1.1: The Selection of Optimal Universal Homogeneous Electricity Supply Reliability

1.3 The Correct Level of End Use Reliability

While technical analysis of electricity service PQR can be highly sophisticated, by contrast, analysis of the economics of the PQR of end uses is at best rudimentary. If the universal PQR is inadequate, backup generation or power conditioning provision is made (often backup is a requirement, e.g., at hospitals), but otherwise the universal quality is accepted. Consider the pyramid in Figure 1.2, which is loosely based on food pyramids.[8]

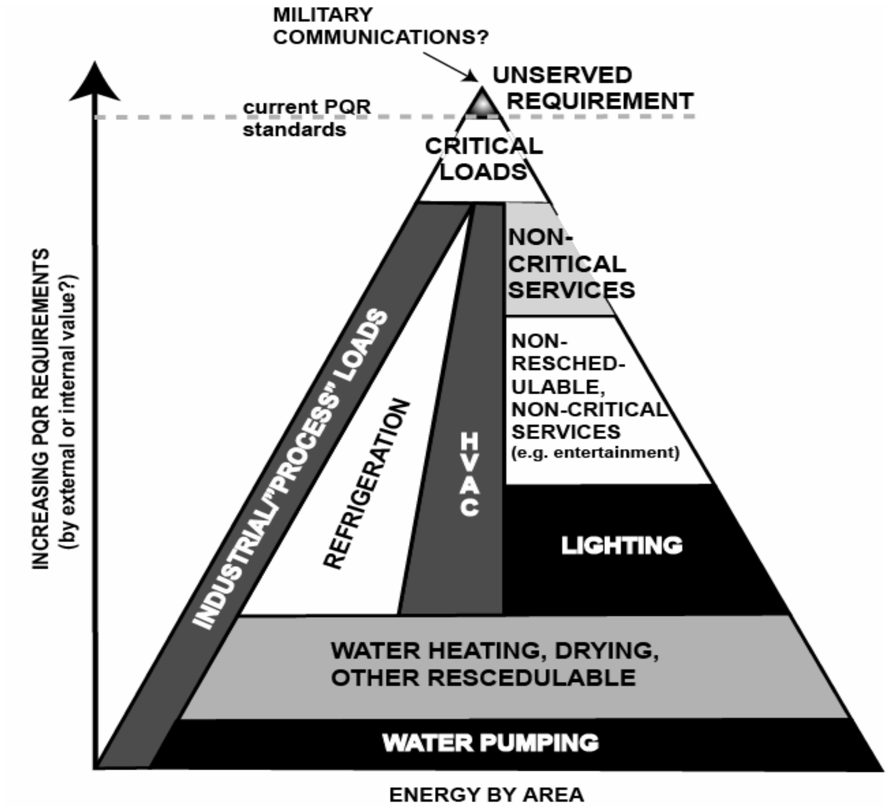

Figure 1.2: A Power Quality and Reliability Pyramid

The figure illustrates how various electricity uses might be classified by their PQR requirements. Some common loads are widely agreed to have low PQR needs and appear at the bottom of the pyramid, and vice-versa. Other loads can be much harder to classify, e.g., refrigeration is re-schedulable in many applications, but might be critical in others, such as medication storage. At the top of the pyramid the exposed peak shows that not all requirements are currently met, i.e. a cut off exists. Here two observations are offered:

1. the choice of the cut-off level is somewhat arbitrary and not based on an analysis of costs and benefits as explained above; and
2. little analysis or data collection has been done to establish the parameters of the pyramid shown in Figure 1.2.

Analysis of PQR in a form like the pyramid could potentially lead to the clustering of like PQR loads on certain circuits and the provision of electricity of appropriate quality to that circuit. At the same time, the effective provision of high PQR locally to sensitive loads could potentially lower the societal optimum for grid service.

1.4 The Digital Society

Early claims that our emerging "digital society" will itself dramatically increase electricity requirements have been fully discredited, and the more real problem that is now being recognised concerns providing

PQR to these growing end uses within their tight tolerances.[9,10,11] Provision of reliable electricity supply close to loads may provide the key to meeting the requirements of the digital society. Considering alternatives is vital, as advanced economies struggle to meet inexorably growing electricity usage, driven more by prosperity than digital loads *per se*, pushing the limits of affordable power quality.

1.5 Limits to Expansion of the Macrogrid

It appears unlikely grids can expand rapidly enough and perform well enough to meet the expanding needs of advanced economies, in large part because of expanding electricity consumption.

California might be considered representative of highly developed and fairly diversified economies. Figure 1.3 indicates the growth in California's electricity consumption over the last two decades. Despite the improvement in the electricity efficiency of the economy, i.e., lower kWh usage per dollar of gross domestic product (GDP) created, per capita electricity usage continues to grow because of economic growth and technological change. Nationally, the latest US Energy Information Administration (EIA) forecasts foresee an increase in national U.S. electricity use of well over half during the first quarter of this century.[12] However optimistic predictions might be of energy efficient technology deployment, this growth trend is unlikely to reverse soon, and the added demand this will place on the national grid is potentially crippling. What makes the scenario much more troubling is that at the same time that our requirements of the grid grow more demanding, both in terms of the amount of energy that needs to be transported and the reliability and quality that needs to be maintained, while the potential for enhancing the grid is becoming more limited.

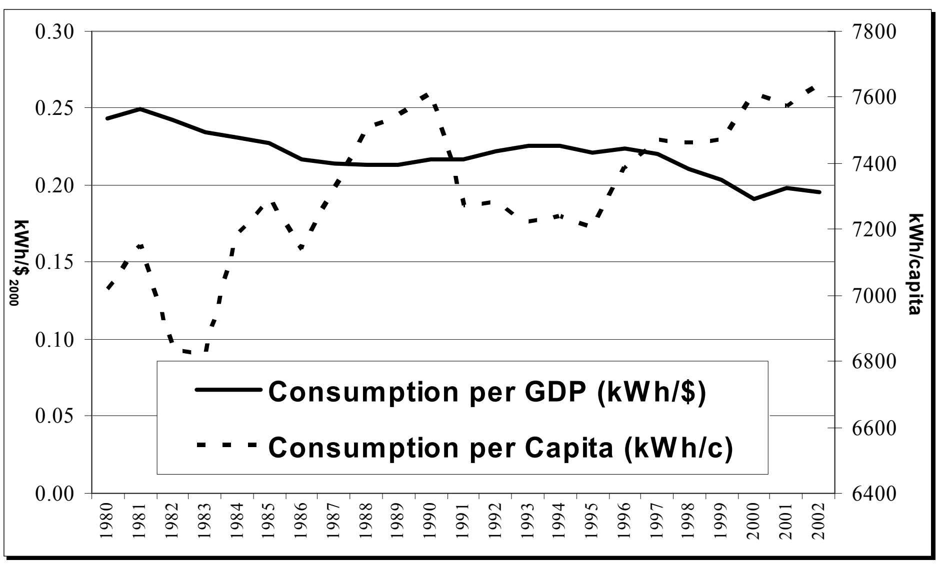

Figure 1.3: Rising Per Capita Electricity Consumption in California (Sources: California Energy Commission, United States Census Bureau, Bureau for Economic Analysis)

Investment in the US grid has been in steady decline for a quarter century.[13] There are numerous possible explanations for this decay, but two of the ones commonly cited are:

1. the uncertainty of cost recovery that transmission owners face given the inconsistent pattern and pace of electricity supply industry restructuring, and
2. the increasing physical and political barriers to siting new transmission lines and equipment.

1.6 Alternatives to a Centralised Grid

Many authors have noted that power systems everywhere began as smaller isolated systems which, wherever possible, have been eventually interconnected and extended, often to eventually cover vast regions; in other words, distributed systems are closer to the roots of the power industry. While this is in a way correct, the march to larger interconnected systems began very early and was fully established soon after the turn of the last century, the triumph of AC over DC being in part driven by its amenability to high voltage long distance transmission of energy.[14] Questioning of the inevitability of larger scales of generation and longer distances of transmission began when the benefits of large scale generation first showed evidence of decline in the late 1960s and gained momentum with the nuclear fiascos of the 1970s and 1980s; however, serious analysis of the potential benefits of establishing a more decentralised system began only in the 1990s. An extensive and rich literature has been accumulated since then. Innovative work done for and by the Pacific Gas and Electric Company first examined and attempted to quantify the benefits of distributed generation, and eventually the general case for a smaller scale less centralised power grid emerged. Iannucci *et al.* provide an excellent summary and review of over 30 major contributions to this literature.[5] The general case for a decentralised power system has been laid out exhaustively by the Rocky Mountain Institute.[3] More recently, Gumerman *et al.*, proposed a simple framework for estimation of societal DER benefits.[4]

In addition to analysis of the implications of emerging smaller scale technologies, work is now emerging on the technical, organisational, and regulatory issues raised by the possible aggregation of small scale generators into localized groupings, or microgrids. The number of definitions of "microgrid" is roughly equivalent to the number of analysts working in this area, and no consensus seems likely soon. But the general feature that seems to unite these concepts is that control of DER in a microgrid advances a step or two beyond the totally passive role that small-scale resources are currently assigned. In other words, most analysts minimally consider a microgrid to be *a grouping on some scale below the utility, usually within the service territory of a distribution utility, and yet operating to some extent outside its control.*

1.7 Development of the CERTS Microgrid Concept

The Consortium for Electric Reliability Technology Solutions (CERTS) is pioneering the concept of the CERTS Microgrid (CM) as an alternative approach for integrating small-scale distributed energy resources (DER of < 500 kW) into electricity distribution systems and the current wider power sector.[16] The viability of the CM has been shown in simulation and in bench tests. A laboratory test is planned for early 2005 to be followed by a field demonstration.[17,18,19] The CM concept fits into the group of emerging microgrid concepts that envisages systems designed to operate semi-independently, usually operating connected to the macrogrid but separating (islanding) from it when cost effective or necessary.

A CM is a semiautonomous grouping of generating sources and end use sinks that are placed and operated for the benefit of its members. The supply sources may include microturbines, fuel cells, PV, and storage devices, all of which are interconnected through power electronic devices that could be enhanced to perform CM functions. Synchronous rotating generators are in a somewhat different class but could also be incorporated. Some end use loads could also be controlled to permit efficient operation of the CM. For example, non-critical loads might be curtailed or shed during times of energy shortfall or high costs. While capable of operating independently of the macrogrid, the CM usually functions interconnected to the macrogrid, purchasing energy and ancillary services from the macrogrid as economic. The CM maintains energy balance through passive plug-and-play electronic interfaces that allow operation without tight central active control or fast communication, i.e., on time scales less than minutes. These interfaces permit connection and disconnection of devices without need for any reconfiguration of equipment, pre-existing or new. Economic operation within constraints, such as air quality restrictions, noise concerns, etc., as well as maintenance of a legitimate façade to the macrogrid, is achieved entirely through slow communications.

Recovery of waste heat by CHP devices represents a central design and operating principle. While small-scale thermal generation of electricity is unlikely to be directly competitive with central station generation, the dramatically improved prospects for useful waste heat recovery, especially in absorption cooling systems, can tip the economic scales towards DER. The arrangement of a CM evolves from the need to optimise the overall energy system of the end uses, and since transportation of heat is typically more limiting than transportation of electricity, the location of heat loads is likely to dominate. In other words, small-scale generators may be distributed throughout sites to permit collocation with heat loads. A second central goal of the CM concerns tailoring PQR to the requirements of end uses, a starkly different principle from the provision of universal service quality, which is the goal of macrogrids. The CM is built and operated so that critical loads are protected and high power quality is ensured where it is necessary, while other loads are served with PQR commensurate with their importance and/or re-schedulability.

1.8 Microgrid Analysis

Figure 1.4 shows the energy flows within a microgrid. On the left side are energy inflows; in California, these are typically utility electricity and natural gas. On the right side are the useful energy flows.

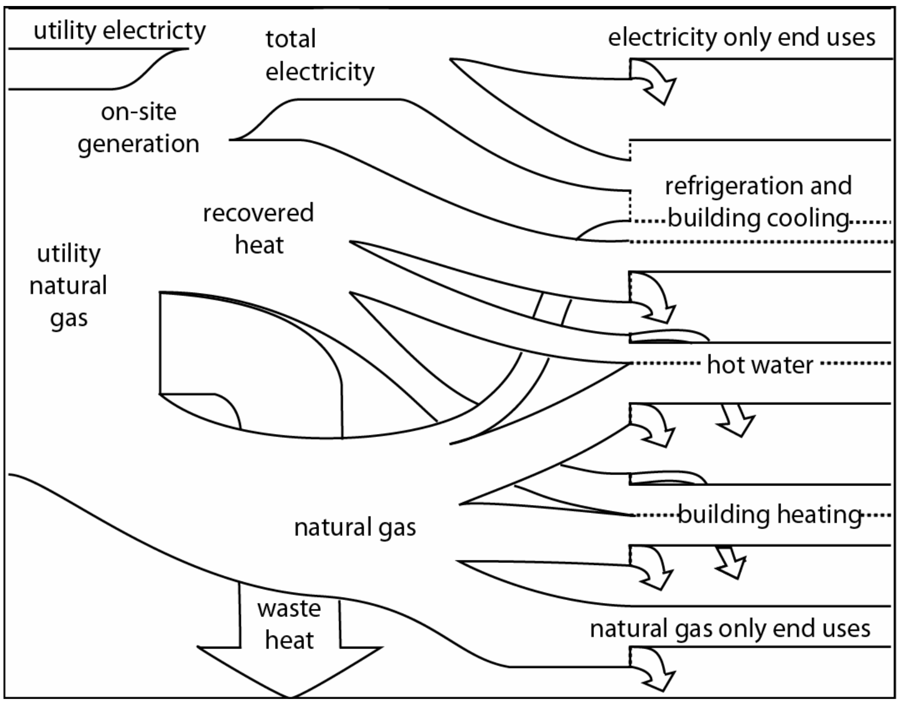

Figure 1.4: Energy Flows in a Microgrid

Here, they are segregated into five categories. Some loads can be met only by electricity, e.g., lighting or computing, and some can be met only by direct natural gas firing, e.g., cooking. Some can be met by either waste heat or direct fire, most notably space heating and domestic hot water production. Finally, the cooling and refrigeration loads are in a special category because they can be served by traditional compressor cooling, by direct gas-fired absorption cooling, or by indirect waste heat driven absorption cooling. The key to optimising microgrid performance is to pick equipment that optimally buys, applies, and converts the energy inflows on the left into the useful energy flows that serve energy needs on the right side. In detail, this can be a highly complex problem, but at a superficial technical level, its economics can be solved analytically, which is what DER-CAM does.

2 PROBLEM STATEMENT

2.1 Introduction

In this section, DER-CAM is presented, including an overview of the present version of the model's mathematical formulation. While this model has been used extensively by Berkeley Lab researchers and results have been previously reported (see [20] and [21]), the current version additionally incorporates CHP-enabled technologies (see [22] and [23]) in order to allow for further cost minimisation through separate selection of distributed generation and heat recovery technologies. All versions of the model have been programmed in the commercial optimisation software, GAMS (General Algebraic Modeling System). The results presented are not intended to represent a definitive analysis of the benefits of DER adoption, but rather as a demonstration of current DER-CAM capability. Developing estimates of realistic customer costs is an important area in which improvement is both essential and possible, and is being actively pursued by the authors in other work.

2.2 Model Description

In its current formulation, the model purchases two fuels, electricity, and natural gas, and supplies five types of end uses, electricity only (e.g., lighting), space- and water-heating, cooling and refrigeration, and natural gas only (i.e., usually just cooking). The model's objective function is to minimise the cost of supplying the four end uses to a specific microgrid during a given year by optimising the distributed generation of part or its entire electricity requirement. In order to attain this objective, the following questions must be answered:

- Which distributed generation and heat recovery technology (or combination of technologies) should the microgrid install?
- What is the appropriate level of installed capacity of these technologies that minimises the cost of meeting the microgrid 's requirements for energy?
- How should the installed capacity be operated in order to minimise the total bill for meeting the microgrid 's five end use requirements?

The essential inputs to DER-CAM are:

- the microgrid 's load profiles
- default energy tariffs (in this work from Southern California Edison (SCE))
- capital, operating and maintenance (O&M), and fuel costs of the various available distributed generation and heat recovery technologies, together with the interest rate on customer investment
- rate of carbon emissions from the macrogrid and from the burning of natural gas for on-site power generation and direct combustion to meet thermal loads
- thermodynamic parameters governing the use of CHP-enabled distributed generation technologies
- the level of carbon tax (set to zero in this study to focus on installation decisions)

Outputs to be determined by the optimisation are the cost minimising:

- technology (or combination of technologies) installed and their respective capacities
- hourly operating schedules for installed equipment
- total cost and carbon emissions of supplying the total energy requirement through either DER or macrogrid generation, or typically, a combination of the two

Of the important assumptions that follow, the first three tend to understate the benefit of DER, while the fourth overstates it:

- Customer decisions are taken based only on direct economic criteria, i.e., the only benefit that the microgrid can achieve is a reduction in its energy bill.
- The microgrid is not allowed to generate more electricity than it consumes. On the other hand, if more electricity is consumed than generated, then the microgrid will buy from the macrogrid at the default tariff rate. No other market opportunities, such as sale of ancillary services and load interrupts, are considered.
- Reliability and power quality benefits, and economies of scale in O&M costs for multiple units of the same technology are not taken into account.
- Manufacturer claims for equipment price and performance are accepted without question. Some of the permitting and other costs are not considered in the capital cost of equipment, nor are start-up losses and some other operating costs.

2.3 Mathematical Formulation

This section describes intuitively the core mathematical problem solved by DER-CAM. First, the input parameters are listed, and the decision variables are defined. Next, the optimisation problem is described.

2.3.1 Input Parameters

Indices

Name	***Definition***
h	Hour {1,2,…,24}
i	Distributed generation technology {the set of technologies selected}
j	Heat recovery technology {the set of technologies selected}
m	Month {1,2,…,12}
p	Period {on-peak, mid-peak, off-peak} On-peak (hours of the day 13 through 18, inclusive), mid-peak (09 through 12 and 19 through 23), or off-peak (01 through 08 plus 24)
s	Season {summer, winter} Summer (June through September, inclusive) or winter (the remaining months)
t	Day type {weekday, weekend, peak}
u	End use {electricity-only, cooling, space heating, water heating, natural gas only}

Customer Data

Name	***Description***
$Cload_{m,t,h,u}$	Customer load (electricity or heating) in kW for end use u during hour h, day type t and month m (end uses are electric-only, cooling, space-heating, water-heating, and natural-gas-only)

Distributed Energy Resource Technologies Information

Name	***Description***
$DERmaxp_i$	Nameplate power rating of distributed generation technology i (kW)
$DERlifetime_i$	Expected lifetime of distributed generation technology i (a)
$DERcapcost_i$	Turnkey capital cost of distributed generation technology i (US$/kW)
$DEROMfix_i$	Fixed annual operation and maintenance costs of distributed generation technology i (US$/kW)
$DEROMvar_i$	Variable operation and maintenance costs of distributed generation technology i (US$/kWh)
$DERhours_i$	Maximum number of hours distributed generation technology i is permitted to operate during the year (h)
$DERCostkWh_{i,m}$	Production cost of distributed generation technology i during month m (US$/kWh)
$AnnuityF_i$	Annuity factor for distributed generation technology i
$CHPmaxp_j$	Power rating of heat recovery technology j (kW)
$CHPlifetime_j$	Expected lifetime of heat recovery technology j (a)
$CHPcapcost_j$	Turnkey capital cost of heat recovery technology j (US$/kW)
$CHPOMfix_j$	Fixed annual operation and maintenance costs of heat recovery technology j (US$/kW)
$CHPOMvar_j$	Variable operation and maintenance costs of heat recovery technology j (US$/kWh)
$AnnuityF_j$	Annuity factor for heat recovery technology j
$CRate_i$	Carbon emissions rate from distributed generation technology i (kg/kWh)
$DCCap$	Capacity of direct-fired natural gas absorption chiller (kW)
$DCPrice$	Turnkey cost of direct-fired natural gas absorption chiller (US$)
$AnnDCPrice$	Annualised cost of direct-fired natural gas absorption chiller (US$)
$DCLifetime$	Expected lifetime of direct-fired natural gas absorption chiller (a)
$S(i)$	Set of end uses that can be met by distributed generation technology i

Market Data

Name	***Description***
$RTPower_{s,p}$	Regulated non-coincident demand charge under the default tariff for season *s* and period *p* (US$/kW)
$RTEnergy_{m,t,h,u}$	Regulated tariff for electricity purchases during hour *h*, type of day *t*, month *m*, and end use *u* (US$/kWh)
$RTCDCharge_m$	Regulated tariff charge for coincident demand, i.e., that occurs at the same time as the monthly system peak during month *m* (US$/kW)
$RTCCharge$	Regulated tariff customer charge (US$)
$RTFCharge$	Regulated tariff facilities charge (US$/kW)
$NGBSF_m$	Natural gas basic service fee for month *m* (US$)
$MktCRate$	Carbon emissions rate from marketplace generation (kg/kWh)
$CTax$	Carbon tax on emission (US$/kg)
$NGCRate$	Carbon emissions rate from burning natural gas to meet heating and cooling loads (kg/kWh)
$NatGasPrice_{m,t,h}$	Natural gas price during hour *h*, type of day *t*, and month *m* (US$/kJ)

2.3.2 Other Parameters

Name	***Description***
$IntRate$	Interest rate on DER investments (%)
$Solar_{m,h}$	Average fraction of maximum solar insolation received (%) during hour *h* and month *m* used to power photovoltaic (PV) cells
$NGHR$	Natural gas heat rate (kJ/kWh)
$t(m)$	Day type in month *m* when system demand peaks
$h(m)$	Hour in month *m* when system demand peaks
$\alpha_{i,j}$	The amount of heat (in kW) recovered from one kW of electricity using distributed generation technology *i* via heat recovery technology *j* (this is equal to 0 for all technologies that are not appropriately equipped with either a heat exchanger or an absorption chiller)
β_u	The amount of heat (in kW) generated from unit kW of natural gas purchased for end use *u* (since the electricity-only load never uses natural gas, the corresponding β_u value equals 0)
$\gamma_{j,u}$	The amount of useful heat (in kW) that can be allocated to end use *u* from unit kW of recovered heat from heat recovery technology *j* (note: since the electricity-only and natural-gas-only loads never use recovered heat, the corresponding $\gamma_{j,u}$ values equal 0)
INF	An extremely large number, i.e., infinity
$InvGen_i$	Number of units of distributed generation technology *i* installed by the customer
$InvCHP_j$	Number of units of heat recovery technology *j* installed by the customer

DC	Indicator variable for installation of a direct-fired natural gas absorption chiller
$GenL_{i,m,t,h,u}$	Generated power by distributed generation technology *i* during hour *h*, type of day *t*, month *m* and for end use *u* to supply the customer's load (kW)
$GasP_{m,t,h,u}$	Purchased natural gas during hour *h*, type of day *t*, and month *m* for end use *u* (kW)
$DRLoad_{m,t,h,u}$	Purchased electricity from the distribution company by the customer during hour *h*, type of day *t*, and month *m* for end use *u* (kW) (this variable is derived from other variables, but listed here for clarity)
$RecHeat_{i,j,m,t,h,u}$	Amount of heat recovered from distributed generation technology *i* via heat recovery technology *j* that is used to meet end use *u* during hour *h*, type of day *t*, and month *m* (kW)

2.3.3 Problem Formulation

It is assumed that the microgrid acquires the residual electricity that it needs beyond its self-generation from the distribution company (disco) at the regulated tariff. However, an alternative formulation in which it purchases power at the wholesale imbalance energy market (IEM) price plus a transmission and distribution adder has been used in other work. The mathematical formulation of the disco purchase problem follows:

$$\min_{\substack{InvGen_i \\ GenL_{i,m,t,h,u} \\ GasP_{m,t,h,u} \\ RecHeat_{i,j,m,t,h,u} \\ InvCHP_j \\ DC}} \sum_m RTFCharge \cdot \max\left(\sum_{u \in \{electric-only, cooling\}} DRLoad_{m,t,h,u} \right)$$

$$+ \sum_m RTCCharge$$

$$+ \sum_s \sum_{m \in s} \sum_p RTPower_{s,p} \cdot \max\left(\sum_{u \in \{electric-only, cooling\}} DRLoad_{m,(t,h) \in p,u} \right)$$

$$+ \sum_m \sum_{u \in \{electric-only, cooling\}} RTCDCharge_m \cdot DRLoad_{m,t(m),h(m),u}$$

$$+ AnnDCPrice \cdot DC$$

$$+ \sum_m \sum_t \sum_h \sum_u DRLoad_{m,t,h,u} \cdot \left(RTEnergy_{m,t,h} + CTax \cdot MktCRate \right)$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u GenL_{i,m,t,h,u} \cdot DERCostkWh_i$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u GenL_{i,m,t,h,u} \cdot DEROMvar_i$$

$$+ \sum_i \sum_m \sum_t \sum_h GenL_{i,m,t,h} \cdot CTax \cdot CRate_i$$

$$+\sum_i \sum_j \sum_m \sum_t \sum_h \sum_u RecHeat_{i,j,m,t,h,u} \cdot CHPOMvar_j$$

$$+\sum_i InvGen_i \cdot DERmaxp_i \cdot \begin{pmatrix} DERcapcost_i \cdot AnnuityF_i + \\ DEROMfix_i \end{pmatrix}$$

$$+\sum_m NGBSF_m$$

$$+\sum_m \sum_t \sum_h \sum_u GasP_{m,t,h,u} \cdot NGHR \cdot \begin{pmatrix} NatGasPrice_{m,t,h} \\ + CTax \cdot NGCRate \end{pmatrix}$$

$$+\sum_j InvCHP_j \cdot CHP\max p_j \cdot \begin{pmatrix} CHPcapcost_j \cdot AnnuityF_j \\ + CHPOMfix_j \end{pmatrix}$$

(1)

Subject to:

$$Cload_{m,t,h,u} = \sum_i GenL_{i,m,t,h,u} + DRLoad_{m,t,h,u} + \beta_u \cdot GasP_{m,t,h,u} + \sum_i \sum_j \left(\gamma_{j,u} \cdot RecHeat_{i,j,m,t,h,u}\right) \forall\, m,t,h,u \tag{2}$$

$$AnnuityF_i = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{DERlifetime_i}}\right)} \forall\, i \tag{3}$$

$$\sum_u GenL_{i,m,t,h,u} \le InvGen_i \cdot DER\max p_i \cdot Solar_{m,h} \quad \forall\, i,m,t,h \tag{4}$$

$$\sum_m \sum_t \sum_h \sum_u GenL_{i,m,t,h,u} \le InvGen_i \cdot DER\max p_i \cdot DERhours_i \;\; \forall\, i \tag{5}$$

$$\sum_j \sum_u RecHeat_{i,j,m,t,h,u} \div \alpha_{i,j} \le \sum_u GenL_{i,m,t,h,u} \;\forall\, i,m,t,h \tag{6}$$

$$\sum_i \sum_u RecHeat_{i,j,m,t,h,u} \le InvCHP_j \cdot CHP\max p_j \quad \forall\, j,m,t,h \tag{7}$$

$$RecHeat_{i,j,m,t,h,u} = 0 \quad \forall\, i,j,m,t,h \quad if \quad u \notin S(i) \tag{8}$$

$$GenL_{i,m,t,h,u} = 0 \quad \forall\, i,m,t,h \quad if \quad u \in \{space-heating, water-heating, natural\text{-}gas\text{-}only\} \tag{9}$$

$$GasP_{m,t,h,u} \leq \mathrm{DCCap} \cdot \mathrm{DC} \quad \forall\, m,t,h \quad \mathit{if} \quad u \in \{cooling\} \tag{10}$$

$$DRLoad_{m,t,h,u} = 0 \quad \forall\, m,t,h \tag{11}$$
$$\mathit{if} \quad u \in \{space-heating, water-heating, natural-gas-only\}$$

$$AnnDC\,\mathrm{Pr}\,ice = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{DCLifetime}}\right)} \cdot DC\,\mathrm{Pr}\,ice \tag{12}$$

$$\sum_i \sum_u \mathrm{Re}\,cHeat_{i,j,m,t,h,u} \leq InvCHP_j \cdot INF \quad \forall\, j,m,t,h \tag{13}$$

$$AnnuityF_j = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{CHPlifetime_j}}\right)} \forall\, j \tag{14}$$

Equation (1) is the objective function that states that the microgrid will try to minimise total energy cost, consisting of facilities and customer charges, monthly demand charges, coincident demand charges, and disco energy charges inclusive of carbon taxation. In addition, the microgrid incurs on-site generation fuel and O&M costs, carbon taxation on on-site generation, and annualised distributed generation and heat recovery equipment investment costs. Finally, for natural gas used to meet heating and cooling loads directly, there are variable and fixed costs (inclusive of carbon taxation).

The constraints to this problem are expressed in equations (2) through (14):

- equation (2) enforces energy balance (it also indicates the means through which the load for energy end use *u* may be satisfied)
- equations (3) and (14) annualise the capital costs of owning distributed generation and heat recovery equipment over their respective lifetimes
- equation (4) constrains distributed generation technology *i* to generate no more than its installed capacity and in proportion to the solar insolation
- equation (5) places an upper limit on how many hours each type of distributed generation technology can generate during the year (local air quality regulations restrict the yearly operating hours of diesel generators)
- equation (6) limits how much heat can be recovered from each type of distributed generation technology
- equation (7) constrains a heat recovery unit from processing more heat than its given power rating
- equation (8) prevents the use of recovered heat by end uses that cannot be satisfied by the particular distributed generation technology
- equations (9) and (11) are boundary conditions that prevent electricity from being used directly to meet heating loads
- equation (10) prevents direct burning of natural gas to meet the cooling load if no absorption chiller for this purpose is purchased
- equation (12) annualises the turnkey costs of the direct-fired absorption chiller over its lifetime

- equation (13) prevents the use of recovered heat if no heat recovery equipment has been installed

3 PORT HUENEME STUDY SITE

Naval Base Ventura County (NBVC) is analysing the cost effectiveness of DER systems at different facilities on site, with Berkeley Lab executing the analysis using DER-CAM. NBVC is comprised of two nearby bases located 100 km (60 miles) northwest of Los Angeles: the Naval Air Station (NAS) at Point Mugu and the Construction Battalion Center (CBC) at Port Hueneme, founded in 1941 and 1942, respectively. NBVC employs over 6,000 civilians, 9,000 military personnel, and 1,300 contractors.

Port Hueneme's Building 1512 was selected after a site visit by Berkeley Lab staff because it has the highest electricity use on the two bases, has relatively easy visitor access, has opportunities for absorption cooling, and has other neighbouring buildings with substantial thermal loads that may ultimately become part of a broader microgrid. For example, a swimming pool facility next door will be powered and partially heated by a microturbine that is currently being installed. Building 1512 is approximately 13,000 m^2 (136,000 ft^2) and houses a Navy Exchange (NEX, a retail store), the Commissary (a grocery store), and many smaller businesses, notably a food court. The site is, therefore, similar to a small shopping mall.

The Naval Base purchases electricity from Strategic Energy LLC, and retail and delivery services from SCE under a legacy, i.e., effective prior to September 2001, energy service provider (ESP) contract. Natural gas is procured through the Defense Energy Support Center in Fort Belvoir, Virginia and delivered by Southern California Gas (SoCalGas). NBVC Public Works Department recharges base facilities at fixed prices for electricity, natural gas, and water based on metered consumption.

3.1 Ongoing Energy Activity at NBVC

Port Hueneme has several energy projects and demonstrations ongoing. A standby generator optimisation review was performed by C&H Engineering under subcontract to SoCalGas (see [24]). The Public Works building is powered by a 31 kW rooftop PV system, which serves all power requirements for the building and acts as an uninterruptible power supply (UPS). On sunny days, the PV supplies power into the base's electricity network. There are also four solar thermal collectors supplying the building's hot water requirements.

Given the current tariff structure there are two main decisions facing NBVC: whether to install DER, and whether to continue the direct access energy supply contract or switch to the Public Works Flat Recharge Rate (PWFRR). Each of these decisions would have to be made at different levels, perhaps involving different decision makers: at the building level for a DER system and at the base level for continuing the direct access contract.

3.2 Operating Scenarios

These cases are summarised in Table 3.1.

Table 3.1: Description of Scenarios Analysed at NBVC

Scenario	**Case Name**	**Electricity Tariff**	**Natural Gas Tariff**
No DER installation	No DER Flat Rate	Public Works Flat Recharge Rate	Public Works Flat Recharge Rate
	No DER Direct Access	Direct Access	Direct Access
Packaged Installation of DER and CHP Pre-determined combination of distributed generation and heat recovery	DER Pack Flat Rate Separate	Public Works Flat Recharge Rate	Public Works Flat Recharge Rate
	DER Pack Direct Access Separate	Direct Access	Direct Access
Separate Installation of DER and CHP Any technology combination allowed (true optimisation)	DER Flat Rate Separate	Public Works Flat Recharge Rate	Public Works Flat Recharge Rate
	DER Direct Access Separate	Direct Access	Direct Access

To explore the potential options available for DER installation, two scenarios were modelled. Both scenarios provide information useful for determining the financial benefits of different DER system designs, and each was modelled under the two different tariffs, PWFRR and the actual effective direct access contract rate. Notice also that the cases that use the flat recharge rate also use the flat natural gas rate while the other cases use a direct access gas rate. The "no DER installation" scenario provides the baseline for determining any financial benefits of DER systems, and the "separate installation of DER" scenario is the actual optimisation, i.e., the model may select any combination of distributed generation and heat recovery technologies and operating schedules. The "packaged installation of DER" scenario considers the optimisation, but with the restriction that each heat recovery unit can be used by only one specific distributed generator.

3.3 Load Profiles

Ideally, complete electric and thermal load profiles on an *hourly* basis for a full year (historical, or even better, forecast) would be available as inputs to DER-CAM. At NBVC, however, hourly data, peak load data, or other load shape information were not available. Deborah Stewart, Public Utilities Specialist, provided a spreadsheet containing the monthly meter readings for both the Commissary and the NEX building for five years (November 1998 to January 2004), i.e., energy consumption since the last meter reading in MWh and MBTU. The tariff situation at NBVC is complex, as described below, and a major effort was required to unravel it. These monthly electric and natural gas meter data were averaged to obtain baseline monthly electric and natural gas consumption.

The DOE-2 building energy simulator was used to develop hourly electricity, heating, and cooling loads, which were otherwise unavailable. The following building types were used to approximate Building 1512: a retail store (NEX), a supermarket (Commissary), and a fast food restaurant (the food court).

The five DER-CAM load types used in this study are:

- electric-only: loads met only by electricity that cannot be met by natural gas or heat recovery (i.e., lighting, computing, etc.),
- space cooling: loads met by electricity or heat recovery through absorption chillers,
- space heating: loads met either directly by natural gas or with residual heat from heat recovery,
- water heating: loads met either directly by natural gas or with residual heat from heat recovery,
- natural-gas-only: loads met only by natural gas and not heat recovery opportunities (i.e., primarily cooking).

The outputs were added to total the loads for each major component of building 1512 and then adjusted to match the historic metered data (from November 1998 to January 2004). Electric-only and cooling loads from DOE-2 were multiplied by a factor of 0.96 to calibrate them to the average loads provided by historic meter readings. The space heating, water heating, and natural-gas-only loads from DOE-2 were multiplied by 0.85. The test site load profiles described in this report are presented in Figure 3.1 through Figure 3.3.

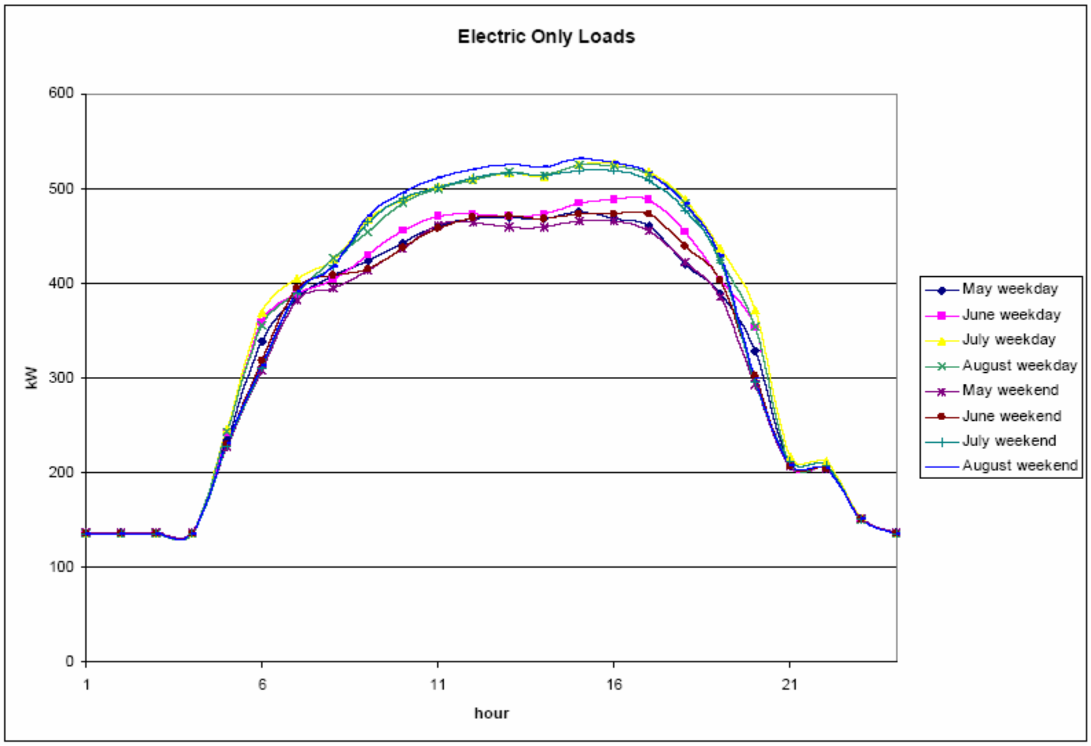

Figure 3.1: Electric-Only Sample Load Profile

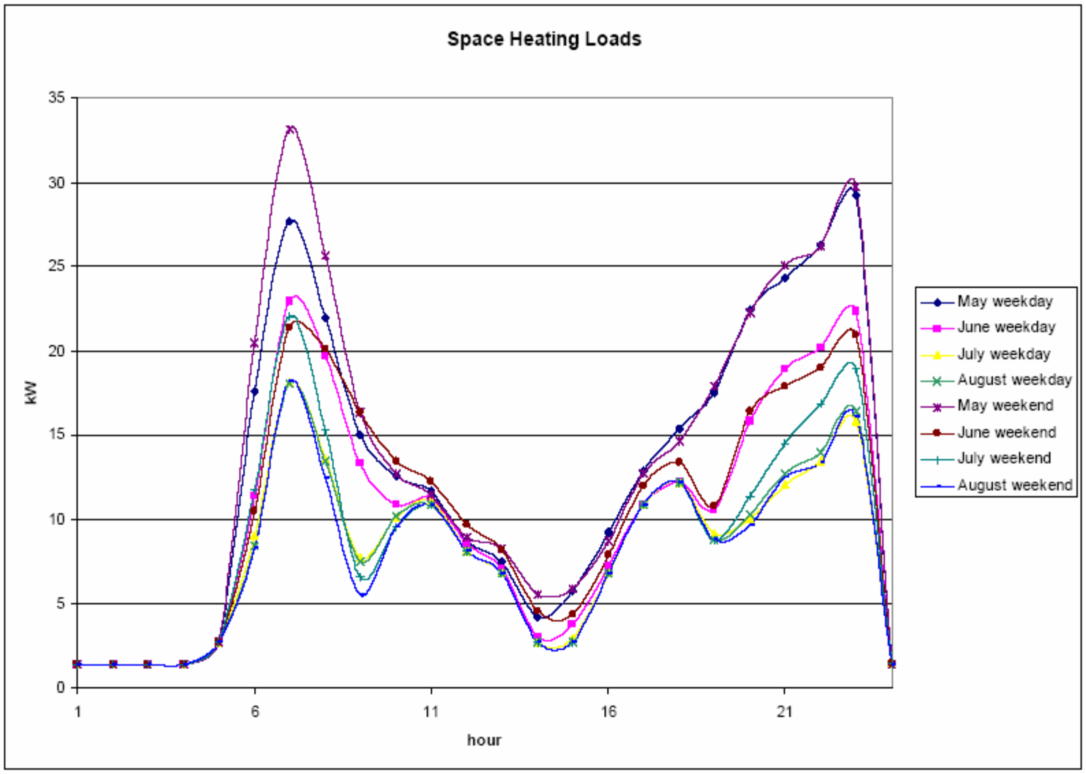

Figure 3.2: Space Heating Sample Load Profile

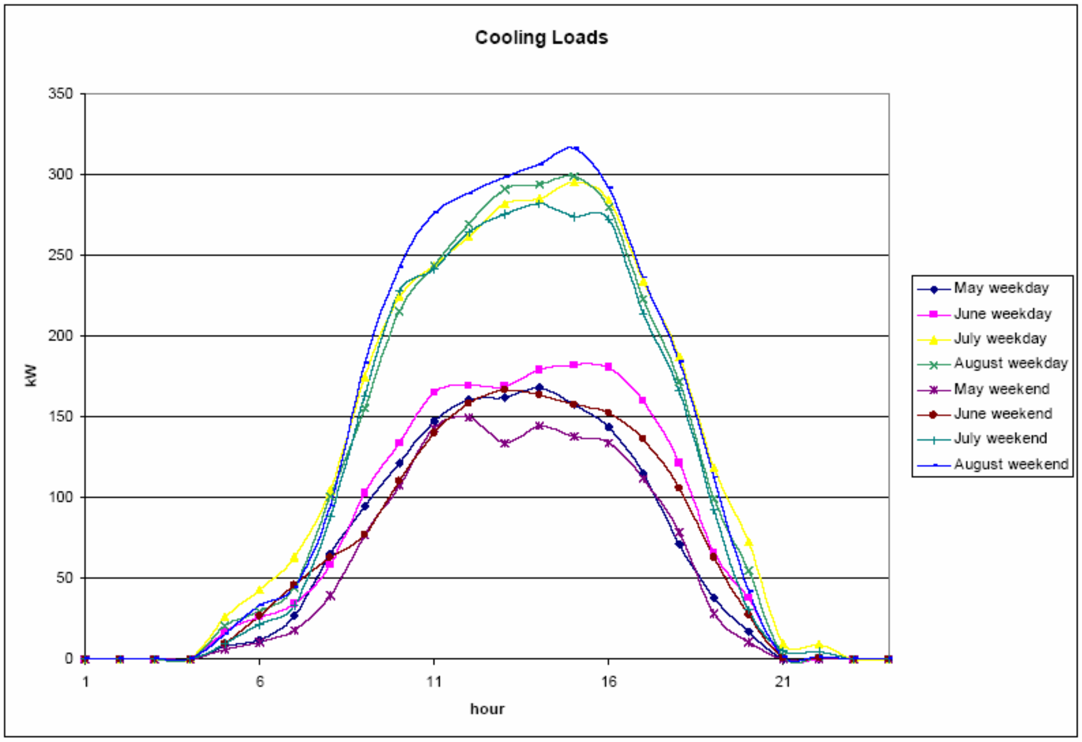

Figure 3.3: Sample Cooling Load Profile

3.4 Tariff Information

3.4.1 Direct Access

NBVC has a direct access contract with an energy service provider, Strategic Energy, and electricity delivery services are through SCE under tariff TOU-8 Direct Access. The Strategic Energy contract is effective through March 2005 and is renewable indefinitely. Natural gas is also purchased from a direct supplier and SoCalGas charges for delivery. The net tariff estimated by combining the Strategic Energy charge and the SCE TOU-8 direct access charge is here called the "direct access" tariff. The energy and demand charges are summarised by Table 3.2. In addition, there is a customer charge (US$/meter/month) of 224.22 and a facility charge (US$/kW/month) of 1.51, along with a stand-by charge of US$0.44/kW/month. The natural gas charge is US$6.057/GJ each month, along with a basic service fee of US$350/month.

Table 3.2: Direct Access Tariff

	Strategic energy (US$/kWh)	**SCE TOU-8 Direct Access Delivery Service** (US$/kWh)	**SCE TOU-8 HPC, DWR Power and Bond charges**	**Total Tariff TOU rate** (US$/kWh)	**Total Demand Charges** (US$/kW)
On-Peak Summer	0.0643	0.00686	0.027	0.09816	6.91
Mid-Peak Summer	0.0643	0.00686	0.027	0.09816	0.46
Off-Peak Summer	0.0643	0.00686	0.027	0.09816	0
On-Peak Winter	0.0643	0.00686	0.027	0.09816	1.61
Mid-Peak Winter	0.0643	0.00686	0.027	0.09816	0
Off-Peak Winter	0.0643	0.00686	0.027	0.09816	0

3.4.2 Public Works Flat Rate

The Public Works Department of NBVC recharges a "flat" rate for electricity and gas to each building that is quite different from the direct access tariff. Port Hueneme and Point Mugu each has a unique rate that is charged to all buildings at each base. Building 1512 at Port Hueneme is billed a flat rate of US$133.49/MWh for electricity and US$7.12/GJ for natural gas. There are no monthly customer charges or demand charges.

3.5 Technology and Thermodynamic Data

The available generating technologies are Katolight natural gas reciprocating engine generators and photovoltaic (PV) cells. Diesel engines were considered in this study but restricted to running for less than 52 hours per year due to regional air quality restrictions. In such situations, diesel engines provide value as a back-up power source during outages, but do not provide energy cost savings. DER-CAM has the capability to consider diesel engines and limits (when applicable) on their annual operating hours. Furthermore, microturbines were found to be unattractive during trial runs, and therefore, excluded from the current analysis.

For each of the considered technologies, the nameplate capacity (kW), technology lifetime (a), turnkey cost (US$/kW), operational and maintenance fixed (US$/kWa) and variable costs (US$/kWh), heat rate (kJ/kWh), and fuel requirements (natural gas or solar radiation) are provided (see Table 3.3 for details). Turnkey costs for all equipment are annualised using an interest rate of 7.5% per annum. Since the state of California provides a subsidy for PV equipment, their turnkey costs are reduced by 50%. CHP-enabled technologies have higher turnkey costs to account for the additional expenses associated with purchase and installation of heat exchangers, absorption chillers, and the related infrastructure. As part of the analysis, the microgrid is allowed to install the distributed generation and heat recovery equipment separately in order to take advantage of the fact that a given heat exchanger or absorption chiller can be employed by several different generators as long as they are within the same class of equipment.

Table 3.3: Distributed Generation Technology Data

Name	**DER Type**	**Rated Power** (kW)	**Life-time** (years)	**Turnkey Cost** (US$/kW)	**O&M Fixed Cost** (US$/kW/year)	**O&M Variable Cost** (US$/kWh)	**Heat Rate** (kJ/kWh)	**Carbon Emission** (kg/kWh)
DE-K-15	Diesel Engine	15	20	2257	26.5	0.000033	18288	0.35
DE- K-30	Diesel Engine	30	20	1290	26.5	0.000033	11887	0.22
DE- K-60	Diesel Engine	60	20	864	26.5	0.000033	11201	0.21
DE- K-105	Diesel Engine	105	20	690	26.5	0.000033	10581	0.20
DE- K-200	Diesel Engine	200	20	514	26.5	0.000033	11041	0.21
DE- K-350	Diesel Engine	350	20	414	26.5	0.000033	10032	0.19
DE- K-500	Diesel Engine	500	20	386	26.5	0.000033	10314	0.20
DE- C-7	Diesel Engine	7.5	20	627	26.5	0.000033	10458	0.20
DE- C-20	Diesel Engine	20	20	1188	26.5	0.000033	12783	0.24
DE- C-40	Diesel Engine	40	20	993	26.5	0.000033	11658	0.22
DE- C-100	Diesel Engine	100	20	599	26.5	0.000033	10287	0.19
DE- C-200	Diesel Engine	200	20	416	26.5	0.000033	9944	0.19
DE- C-300	Diesel Engine	300	20	357	26.5	0.000033	10287	0.19
DE- C-500	Diesel Engine	500	20	318	26.5	0.000033	9327	0.18
GA- K-25	Natural Gas Engine	25	20	1730	26.5	0.000033	15596	0.21
GA- K-55	Natural Gas Engine	55	20	970	26.5	0.000033	12997	0.18
GA- K-100	Natural Gas Engine	100	20	833	26.5	0.000033	15200	0.21
GA- K-215	Natural Gas Engine	215	20	1185	26.5	0.000033	13157	0.18
GA- K-500	Natural Gas Engine	500	20	936	26.5	0.000033	12003	0.16
PV-5	Photovoltaic	5	30	4370	14.3	0	0	0.00
PV-20	Photovoltaic	20	30	4070	14.3	0	0	0.00
PV-50	Photovoltaic	50	30	3970	12	0	0	0.00
PV-100	Photovoltaic	100	30	3920	11	0	0	0.00

The National Renewable Energy Laboratory (NREL, http://www.nrel.gov/) provides solar insolation data. In addition, for heat recovery technologies, such as heat exchangers and/or absorption chillers, thermodynamic parameters (as defined in 2.3.2) $\alpha_{i,j}$ and $\gamma_{j,u}$ describe the recoverable waste heat and heat exchanger efficiency, respectively: $\alpha_{i,j}$ is the ratio of recoverable heat (kW) to electricity generated (kW) by distributed generation technology *i,* and heat recovery technology *j* and ranges from 0.72 and 1.72 for the technologies in Table 3.3; $\gamma_{j,u}$ is assumed to be 0.8 for conversions of waste heat to useful heat and 0.13 for conversions of waste heat to cooling; β_u is the efficiency of converting fuel energy into end uses and is assumed to be 0.8 for fuel to heating conversion and 0.13 for fuel to cooling conversions. The lower value of $\gamma_{j,u}$ and β_u for cooling accounts for the fact that indirect-fired absorption cooling is inefficient compared to compressor cooling. Roughly seven times more energy (in the form of low temperature waste-heat) is required to provide the same amount of cooling as an electric compressor, and direct-fired absorption chillers require roughly four times more input energy. Note however, that absorption cooling, either direct fired or by waste heat, can still be attractive economically to a microgrid because of the high cost on-peak power used by cooling, especially when demand charges are in place. The turnkey costs of the heat recovery technologies are listed in Table 3.4. It is assumed that all O&M fixed and variable costs are zero for these.

Table 3.4: Heat Recovery Technology Data

Name	**Turnkey Cost** (US$/kW)	**Rated Power** (kW)	**Life-time** (years)
CHPGA-K-25	195	25	20
CoolGA-K-25	1500	25	20
CoolCHP-GA-K-25	2902	25	20
CHPGA-K-55	154	55	20
CoolGA-K-55	997	55	20
CoolCHP-GA-K-55	1830	55	20
CHPGA-K-100	190	100	20
CoolGA-K-100	1088	100	20
CoolCHP-GA-K-100	1852	100	20
CHPGA-K-215	164	215	20
CoolGA-K-215	796	215	20
CoolCHP-GA-K-215	1730	215	20
CHPGA-K-500	150	500	20
CoolGA-K-500	438	500	20
CoolCHP-GA-K-500	1116	500	20

4 RESULTS

Using the data from the NBVC site, six cases of DER-CAM were run in GAMS. The results indicate that the microgrid has an economic incentive to adopt distributed generation along with heat recovery equipment, such as heat exchangers and absorption chillers. Indeed, in the cases where adoption was allowed, the microgrid invested heavily in distributed generation, usually covering a significant fraction of its peak electric-only load. Under both the flat rate and the direct access tariffs, the facility does not purchase any energy from the utility (see Table 4.1). Instead, it becomes nearly self-sufficient, producing all of its electricity on-site, and using heat recovery technologies to meet heating and cooling loads. The sole exception is the natural-gas-only load, which cannot be met via CHP applications.

Table 4.1: Annual Building 1512 Energy Results

Case	*Generation Installed (kW)*	*% of Peak Load*	*Equipment*	*Annual Utility Purchase*			*Annual DER Production*		
				Electricity (MWh)	*Gas for DER (MWh)*	*Gas for direct end use (MWh)*	*Electricity Loads (MWh)*	*Abs Cool (MWh)*	*Thermal Loads (MWh)*
No DER Direct Access				3553	N/A	426	N/A	N/A	N/A
No DER Flat Rate				3553	N/A	426	N/A	N/A	N/A
DER Pack Direct Access	1110	92	300 kW diesel, 200 kW NG, 110 kW NG-HE, 500 kW NG-AC	0	11120	161	3308	245	298
DER Pack Flat Rate	1105	92	300 kW diesel, 155 kW NG, 40 kW PV, 110 kW NG-HE, 500 kW NG-AC	0	10673	161	3315	238	298
DER Separate Direct Access	1100	91	100 kW NG, 1000 kW NG, 100 kW HE, 500 kW AC	0	10969	141	3289	264	314
DER Separate Flat Rate	1102	92	307.5 kW diesel, 775 kW NG, 20 kW PV, 100 kW HE, 500 kW AC	0	10745	141	3293	261	314

Table 4.2: Annual Building 1512 Financial Results

Case	*Capacity Installed (kW)*	*Equipment*	*Investment Costs (kUS$/a)*	*Annual Utility Bills*			*Total Energy Cost (kUS$)*	*Average Energy Price (US$/kWh)*	*Bill Savings Over No DER Case (%)*	*Carbon Emissions (t/a)*
				Electricity (kUS$)	*Gas for DER (kUS$)*	*Gas for direct end use (kUS$)*				
No DER Direct Access				406	0	16	422	0.1061	N/A	488
No DER Flat Rate				474	0	14	488	0.1226	N/A	488
DER Pack Direct Access	1110	300 kW diesel, 200 kW NG, 110 kW NG-HE, 500 kW NG-AC	113	3	244	8	368	0.0924	13	560
DER Pack Flat Rate	1105	300 kW diesel, 155 kW NG, 40 kW PV, 110 kW NG-HE, 500 kW NG-AC	125	0	275	4	404	0.1014	17	538
DER Separate Direct Access	1100	100 kW NG, 1000 kW NG, 100 kW HE, 500 kW AC	92	3	239	7	365	0.0917	14	549
DER Separate Flat Rate	1102	307.5 kW diesel, 775 kW NG, 20 kW PV, 100 kW HE, 500 kW AC	97	0	277	4	401	0.1007	18	541

By investing in distributed generation and heat recovery equipment, the microgrid avoids the tariff's cost structure, which is not customised to its own needs. Indeed, by installing distributed generation and heat recovery equipment separately on-site, the NBVC creates a power supply that more closely matches its requirements. Consequently, the total energy bill for the facility decreases by 14% and 18% under the direct access and flat rate tariffs, respectively (see Table 4.2). This is a modest 1% improvement over the scenarios in which distributed generation and heat recovery systems are pre-packaged. Note that although carbon emissions increase with DER installation, a carbon tax can be an effective instrument to mitigate this result (see [23]). Furthermore, in the direct access cases, the microgrid incurs an electricity utility charge even though it does not purchase any electricity under the tariff. This is simply due to the monthly customer charge imposed under this tariff.

5 CONCLUSIONS

This work considers DER adoption as a tool for customer-oriented energy cost minimisation. This stands in contrast to much past study of DER, which has tended to consider it an additional option available to utility planners and systems. The starting point here is to minimise the cost of meeting the known electrical and heat loads of a microgrid. Techniques for optimally solving the cost minimizing electricity supply problem have been developed over many years for planning and operating utility scale systems. Since the customer-scale problem is essentially similar to the utility-scale problem, established methods can be readily adapted. In this study, however, the approach is significantly extended to optimise jointly the potential use of CHP by the microgrid. While the patterns of potential customer adoption and generation are interesting in themselves, this model is further used to answer specific policy questions:

1. How does the economic and regulatory environment affect the microgrid's decision to invest in DER technologies?
2. How does the option to select distributed generation and heat recovery equipment separately in the optimisation affect the overall costs?

The Berkeley Lab has developed DER-CAM for these studies to examine the economics of DER adoption for specific sites and microgrids. DER-CAM models specific sites and selects optimal DER systems to install in parallel to the macrogrid, given utility tariffs, fuel costs, and equipment performance characteristics. This paper provides a mathematical description of DER-CAM and the input data it requires specifically for the NBVC, and then provides results based that address the aforementioned policy issues.

The results indicate the potential benefits of distributed generation in lowering costs for the microgrid, especially when faced with a flat-rate tariff. In particular, DER-CAM finds that optimal selection of distributed generation and heat recovery equipment lowers overall energy costs by about 15%, depending on the type of tariff employed. Further reductions of 1% are possible if the NBVC is allowed to select heat recovery equipment independently of the generators. This improvement is modest because the model does not allow natural gas heat recovery equipment to be used by diesel generators. It also precludes the consideration of turnkey cost reductions on multiple units of the same heat recovery equipment installed. Relaxation of these conditions would make the separate optimisation even more attractive to the microgrid.

For future work, more accurate data are required on the technologies and thermodynamic processes. Specifically, the capacity for heat storage implies that heat produced in one period may be available for use in subsequent ones. This could lower the costs of using DER even further. At the same time, however, DER technologies have part-load efficiencies, which would inhibit their economic usage at low capacities. Such a constraint would likely increase the costs of self-generation.

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7 ACKNOWLEDGMENT

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