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Customer Adoption of Small-Scale On-Site Power Generation

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Abstract

The electricity supply system is undergoing major regulatory and technological change with significant implications for the way in which the sector will operate (including its patterns of carbon emissions) and for the policies required to ensure socially and environmentally desirable outcomes. One such change stems from the rapid emergence of viable small-scale (i.e., smaller than 500 kW) generators that are potentially competitive with grid delivered electricity, especially in combined heat and power configurations. Such distributed energy resources (DER) may be grouped together with loads in *microgrids*. These clusters could operate semi-autonomously from the established power system, or *macrogrid*, matching power quality and reliability more closely to local end-use requirements. In order to establish a capability for analysing the effect that microgrids may have on typical commercial customers, such as office buildings, restaurants, shopping malls, and grocery stores, an economic model of DER adoption is being developed at Berkeley Lab. This model endeavours to indicate the optimal quantity and type of small on-site generation technologies that customers could employ given their electricity requirements. For various regulatory schemes and general economic conditions, this analysis produces a simple operating schedule for any installed generators. Early results suggest that many commercial customers can benefit economically from on-site generation, even without considering potential combined heat and power and reliability benefits, even though they are unlikely to disconnect from the established power system.

1. Introduction

1.1 Microgrid Concept

The expectation that distributed energy resources (DER) will emerge over the next decade to shape the way in which electricity is supplied stems from the following hypotheses:

1. small-scale generating technology, both renewable and thermal, will improve significantly
2. siting constraints, environmental concerns, fossil fuel scarcity, and other limits will impede continued expansion of the existing electricity supply infrastructure
3. the potential for application of small scale combined heat and power (CHP) technologies will tilt power generation economics in favour of generation based closer to heat loads
4. customers will desire for control over service quality and reliability will intensify
5. power electronics will enable operation of semi-autonomous systems.

Together, these forces will make generation of electricity from resources based close to end uses competitive with central station generation.

This research is built upon the fundamental concept of the *microgrid*, which could yield a more decentralised power system. A microgrid consists of a localised semi-autonomous grouping of loads and generation operating under a form of co-ordinated local control, either active or passive. The microgrid is connected to the current power system, or *macrogrid*, in a manner that allows it to appear to the wider grid as a *good citizen*; that is, the microgrid performs as a legitimate entity under grid rules, e.g., as what we currently consider a normal electricity *customer* or *generating unit*.

The microgrid would most likely exist on a small, dense group of contiguous geographic sites that exchange electrical energy through a low voltage (e.g., 480 V) network and heat through exchange of working fluids. In the commercial sector, heat loads may well be absorption cooling. The generators and loads within the cluster are placed and co-ordinated to minimise the joint cost of serving electricity and heat demand, given prevailing market conditions, while operating safely and maintaining power balance and quality. This pattern of power generation and consumption is distinctly different from existing power systems in that the sources and sinks within the cluster can be maintained in a balanced and stable state without active external control or support, possibly within a passively controlled *plug and play* system.

Traditional power system planning and operation hinges on the assumption that the selection, deployment, and financing of generating assets will be tightly coupled to changing requirements and that it will rest in the hands of a centralised authority. The ongoing deregulation of generation represents the first step towards abandoning the centralised paradigm, while the emergence of microgrids represents the second. Microgrids will develop their own independent operational standards and expansion plans, which will significantly affect the overall growth of the power system, and yet they will develop in accordance with their independent incentives. In other words, the power system will be expanding according to dispersed independent goals, not co-ordinated global ones.

The emergence of the microgrid partially stratifies the current strictly hierarchical centralised control of the power system into at least two layers. The upper layer macrogrid is the one with which current power engineers are familiar, i.e., the high voltage meshed power grid. A centralised control centre dispatches a limited set of large assets in keeping with contracts established between electricity and ancillary services buyers and sellers, while maintaining the energy balance and power quality, protecting the system, and ensuring reliability. At the same time, where they operate, the lower layer microgrid jointly locally controls some generation and load to meet end use requirements for energy and power quality and reliability (PQR).

Control of the generating and transmission assets of the macrogrid is governed by extremely precise technical standards that are uniform on regional scales, and the key parameters of the grid, such as frequency and voltage, are maintained strictly within tight tolerances. This control paradigm ensures overall stability and safety and attempts to guarantee that power and ancillary service delivery between sellers and buyers is as efficient and reliable as reasonably possible. However, it should be recognised that uniform standards of PQR are unlikely to match will with the optimal requirements of individual end uses that are highly heterogeneous, i.e., with server farms at one end of the reliability requirement spectrum and water pumps at the other. Microgrids move the PQR choice closer to the end uses and permits it to match the end use's needs more effectively. Microgrids can, therefore, improve the overall efficiency of electricity delivery at the point of end use, and, as microgrids become more prevalent, the PQR standards of the macrogrid can ultimately be matched to the purpose of bulk power delivery.

1.2 CERTS Context

This work described in this paper presents a minor contribution to the wider distributed energy resources research of the Consortium for Electric Reliability Technology Solutions (CERTS, http://certs.lbl.gov). This effort is intended to attack and, hopefully, resolve the technical barriers to DER adoption, particularly those that are unlikely to be of high priority to individual equipment vendors.

1.3 Approach of Current Work

The approach taken in this work is strictly customer oriented. This stands in contrast to past study of DER, which has tended to consider DER as an additional option available to utility planners and systems (Weinberg, C.J., *et al.*, 1993). Further, past work has evaluated the benefits of DER in terms of improved power system performance rather than in terms of enhanced customer control (van Sambeek, 2000). The starting point is to minimise the cost of meeting a known customer electrical load, techniques for which have been developed over many years of effort for the purpose of planning and operating utility scale systems. Since the customer-scale problem is, at the level of analysis of this paper, essentially no different from the utility-scale problem, established methods can be readily adapted. In future work, some of the specific problems related to microgrids will be incorporated, such as the central role of CHP and load control in the microgrid. In this work, however, the approach is purely from a traditional power systems economics perspective. While the patterns of potential customer adoption and generation are interesting in themselves, this model is a means for answering two specific questions:

1. Do conditions exist under which customers will disconnect entirely from the grid?
2. Are there any direct advantages, i.e., such as lower cost of electricity procurement, to being a part of a microgrid?

2. Mathematical Model

2.1 Introduction

In this section, the second version of the DER Customer Adoption Model (DER-CAM) is presented. This version of the model has been programmed in GAMS (General Algebraic Modeling System)[1]. This section contains a description of GAMS and a description of the present version of the model's

[1] GAMS is a proprietary software product used for high-level modelling of mathematical programming problems. It is owned by the GAMS Development Corporation (http://www.gams.com) and is licensed to Berkeley Lab.

mathematical formulation. The results presented are not intended to represent a definitive analysis of the benefits of DER adoption, but rather as a demonstration of the current DER-CAM. For example, only equipment first cost as claimed by the manufacturer is used, while delivery and installation costs are omitted. Developing estimates of realistic customer costs is a key area in which improvement is both essential and possible. On the other side of the scale, possible reliability benefits and CHP applications are also excluded.

2.2 Model Description

In a previous report, the first spreadsheet version of the Customer Adoption Model was described and implemented (Marnay, *et al.*, 2000). The model's objective function, which has not changed, is "to minimise the cost of supplying electricity to a specific customer by optimising the installation of distributed generation and the self-generation of part or all of its electricity." In order to attain this objective, the following issues must be addressed:

- Which distributed generation technology (or combination of technologies) could a given customer install?
- What is the appropriate level of installed capacity of these technologies that minimises cost?
- Will disconnecting from the grid be economically attractive to any kind of customer?
- How should the installed capacity be operated so as to minimise the total customer bill for meeting its electricity load?

It is then possible to determine the technologies and capacity the customer is likely to install, to predict when the customer will be self-generating and/or transacting with the grid, and to determine whether it is worthwhile for the customer to disconnect entirely from the grid.

Key inputs into the model are:

- customers' electricity load profile
- customers' default tariff or purchase contract
- capital, operating and maintenance (O&M), and fuel costs of the various available technologies, together with the interest rate on customer investment
- basic physical characteristics of alternative generating technologies
- former California Power Exchange (CalPX) price at all hours of the test year (1999)

Outputs to be determined by the optimisation are:

- technology (or combination of technologies) to be installed
- capacity of each technology to be installed
- when and how much of the capacity installed will be running
- total cost of supplying electricity
- whether or not the customer should, from an economic point of view, remain connected to the grid

The key assumptions are as follows:

- Customer decisions are taken based only on direct economic criteria. In other words, the only benefit that the customer can achieve is a reduction in its electricity bill.
- All the electricity generated in excess of that consumed is sold to the grid. No technical constraints to selling back to the grid at any particular moment are considered. On the other hand, if more electricity is consumed than generated, then the customer will buy from the grid

under pre-determined contractual agreements or at the default tariff rate. No other market opportunities, such as sale of ancillary services or bilateral contracts, are considered.

- Manufacturer claims for equipment price and performance are accepted without question, nor is any deterioration in output or efficiency during the lifetime of the equipment considered. Furthermore, installation, permitting, and other costs are not considered in the capital cost of equipment and start-up and other operating costs are also not included.
- On the other hand, CHP benefits, 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.
- Possible reliability or power quality improvements accruing to customers are not considered.

2.3 General Algebraic Modelling System (GAMS)

While some less mature simulation tools, such as autonomous agent models, are being applied to DER operational problems by some researchers (see Gibson and Ishii, 1999), this work has been completed using a strictly traditional optimisation package, GAMS.

2.4 Mathematical Formulation

This section describes intuitively the core mathematical problem solved by DER-CAM. It is structured into three main parts. First, the input parameters are listed. Second, the decision variables are defined. Third, the optimisation problem is described for two possible tariff options.

2.4.1 Variables and Parameters Definition

2.4.1.1 Parameters (input information)

Customer Data

Name	***Description***
$Cload_{m,t,h}$	Customer Load in kW during hour *h*, day type[2] *t*, and month *m*.

Market Data

Name	***Description***
$RTPower_{s,p}$	Regulated demand charge under the default tariff for season[3] *s* and period[4] *p* ($/kW)
$RTEnergy_{m,t,h}$	Regulated tariff for energy purchases during hour *h*, type of day *t*, and month *m* ($/kWh)
$RTCCharge$	Regulated tariff customer charge ($)
$RTFCharge$	Regulated tariff facilities charge ($/kW)
$PX_{m,t,h}$	CalPX price during hour *h*, type of day *t*, and month *m* ($/kWh)

Distributed Energy Resource Technologies Information

Name	***Description***

[2] There are three day types: peak (the average of the three days with the biggest load), week (the remaining work days), and weekends.
[3] There are two seasons: summer and winter.
[4] There are three different time-of-use periods (for tariff purposes only): on-peak, mid-peak, and off-peak. Every tariff, TOU-8 for example, has a different definition of these periods.

$DERmaxp_i$	Nameplate power rating of technology *i* (kW)
$DERlifetime_i$	Expected lifetime of technology *i* (years)
$DERcapcost_i$	Overnight capital cost of technology *i* ($/kW)
$DEROMfix_i$	Fixed annual operation and maintenance costs of technology *i* ($/kW)
$DEROMvar_i$	Variable operation and maintenance costs of technology *i* ($/kWh)
$DERCostkWh_i$	Production cost of technology *i* ($/kWh)

Other parameters

Name	***Description***
IntRate	Interest rate on DER investments (%)
DiscoER	Disco non-commodity revenue neutrality adder[5] (¢/kWh)
FixRate	Fixed energy rate (¢/kWh) applied in some cases[6]
StandbyC	Standby charge in $/kW/month that SCE currently applies to its customers with autonomous generation

2.4.1.2 Variables

Name	***Description***
$InvGen_i$	Number of units of the *i* technology installed by the customer
$GenL_{i,m,t,h}$	Generated power by technology *i* during hour *h*, type of day *t*, and month *m* to supply the customer's load (kW)
$GenX_{i,m,t,h}$	Generated power by technology *i* during hour *h*, type of day *t*, and month *m* to sell in the wholesale market (kW)
$DRLoad_{m,t,h}$	Residual customer load (purchased power from the distribution company by the customer) during hour *h*, type of day *t*, and month *m* (kW)

Only the three first variables are decision ones. The fourth one (power purchased from the distribution company) could be expressed as a relationship between the second and third variables. However, for the sake of the model clarity, it has been maintained.

2.4.2 Problem Formulation

There are two slightly different problems to be solved depending on how the customer acquires the residual electricity that it needs beyond its self generation:

1. by buying that power from the distribution company at the regulated tariff; or
2. by purchasing power at the CalPX price plus an adder that would cover the non-commodity cost of electricity.

In this work, a surcharge was introduced in the form of a revenue reconciliation term that was added to the CalPX price or the fixed price. This term was calculated such that, if the customer's usage pattern were identical under the CalPX pricing option and the tariff option, the disco would collect identical revenue from the customer.

[5] This value is added to the CalPX price when the customer buys its power directly to the wholesale market.
[6] If the model user selects this option the customer always buy its energy at the same price

2.4.2.1 Option 1: Buying at the Default Regulated Tariff

The mathematical formulation of the problem follows:

$$\min_{InvGen, GenL, GenX} \sum_{m} RTFCharge \cdot max(DRLoad_{m,t,h}) + \sum_{m} RTCCharge$$
$$+ \sum_{s}\sum_{m \in s}\sum_{p} RTPower_{s,p} \cdot max\left(DRLoad_{m,(t,h)\in p}\right)$$
$$+ \sum_{i}\sum_{m}\sum_{t}\sum_{h}\left(GenL_{i,m,t,h} + GenX_{i,m,t,h}\right) \cdot DERCostkWh_{i}$$
$$+ \sum_{i}\sum_{m}\sum_{t}\sum_{h}\left(GenL_{i,m,t,h} + GenX_{i,m,t,h}\right) \cdot DEROMvar_{i}$$
$$+ \sum_{i} InvGen_{i} \cdot \left(DERcapcost_{i} + DEROMfix_{i}\right) \cdot AnnuityF$$
$$+ \sum_{m}\sum_{i} InvGen_{i} \cdot DERmaxp_{i} \cdot StandbyC$$
$$- \sum_{i}\sum_{m}\sum_{t}\sum_{h}\left(GenX_{i,m,t,h} \cdot PX_{m,t,h}\right) \quad (1)$$

Subject to:

$$Cload_{m,t,h} = \sum_{i} GenL_{i,m,t,h} + DRLoad_{m,t,h} \quad \forall_{m,t,h} \quad (2)$$
$$GenL_{i,m,t,h} + GenX_{i,m,t,h} \le InvGen_{i} \cdot DERmaxp_{i} \quad \forall_{m,t,h} \quad (3)$$
$$GenX_{i,m,t,h} = 0 \ \ if \ \sum_{i} GenL_{i,m,t,h} < Cload_{m,t,h} \quad \forall_{i,m,t,h} \quad (4)$$
$$AnnuityF = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{DERlifetime_{i}}}\right)} \quad (5)$$

Equation (1) is the objective function which says that the customer will try to minimise total cost, consisting of total facilities and customer charges, total monthly demand charges, total on-site generation fuel and O&M costs, total DER investment cost, total standby charges, and *minus* the revenues generated by any energy sales to the grid. Equation (2) enforces energy balance. Equation (3) enforces the on-site generating capacity constraint. Equation (4) prohibits the customer from buying and selling energy at the same time. When this constraint is removed, the model assumes that the customer has a “double meter,” i.e., the customer can buy from the disco and sell to the CalPX at the same time, but cannot buy from the disco and resell the same energy to the CalPX. Indeed, this would create an unbounded arbitrage possibility in some circumstances. Equation (5) simply annualises the capital cost of owning on-site generating equipment.

2.4.2.2 Option 2: Buying from Alternative Energy Providers

The problem mathematical formulation follows:

$$\min_{InveGen, GenL, GenX} \sum_m \sum_t \sum_h DRLoad_{m,t,h} \cdot \left(PX_{m,t,h} + DiscoER/1{,}000\right)$$

$$+ \sum_i \sum_m \sum_t \sum_h \left(GenL_{i,m,t,h} + GenX_{i,m,t,h}\right) \cdot DERCostkWh_i$$

$$+ \sum_i \sum_m \sum_t \sum_h \left(GenL_{i,m,t,h} + GenX_{i,m,t,h}\right) \cdot DEROMvar_i$$

$$+ \sum_i InvGen_i \cdot \left(DERcapcost_i + DEROMfix_i\right) \cdot AnnuityF$$

$$+ \sum_m \sum_i InvGen_i \cdot DERmaxp_i \cdot StandbyC$$

$$- \sum_i \sum_m \sum_t \sum_h \left(GenX_{i,m,t,h} \cdot PX_{m,t,h}\right) \quad (1a)$$

Subject to:

Equations (2) through (5)

This formulation differs only in the objective function, equation (1a), which now charges the CalPX energy price for each hourly time step plus the non-commodity revenue neutrality adder. Note that the same mathematical formulation can be used if the model user wants to simulate a fixed price for all customer energy purchases. In that case, all CalPX hourly prices are simply set to the fixed desired value.

3. Customer Description and Input Data

3.1 Load Shape Data

DER-CAM is run for five typical southern California commercial electricity customers (a restaurant, a grocery store, a shopping mall, an office complex, and the microgrid, i.e., an entity that is composed of the four main customers acting as one). The load profiles were extracted from the Maisy[7] database for 1998. Only customers located in Southern California Edison (SCE) service territory were used, since its tariffs are used for the analysis.

The selected typical commercial customers represent the majority of commercial loads, and are described as follows:

- grocery: food stores
- restaurant: eating and drinking establishments
- office: finance, insurance and real estate, business services, outpatient health care, legal services, school and educational services, general social services, associations and organisations, engineering and management services, miscellaneous services and public administration (whenever the buildings are not federally owned)

[7] Maisy (Market Analysis and Information System) is a proprietary data base of commercial and residential energy and hourly load data. It includes information about building structure, building and end-use energy use, equipment and other variables for over 150,000 customers throughout the U.S. Detailed electricity, natural gas and oil consumption are also provided. The Maisy state-level energy marketing database for commercial sector hourly loads version 2.2. is the one used in this project.

- mall: shopping centres

The data are organised into day-types as described above. Every load data set includes 24 hourly electricity loads (measured in kW) for each of the three day-types for each of the twelve months.

Two sample load profiles follow:

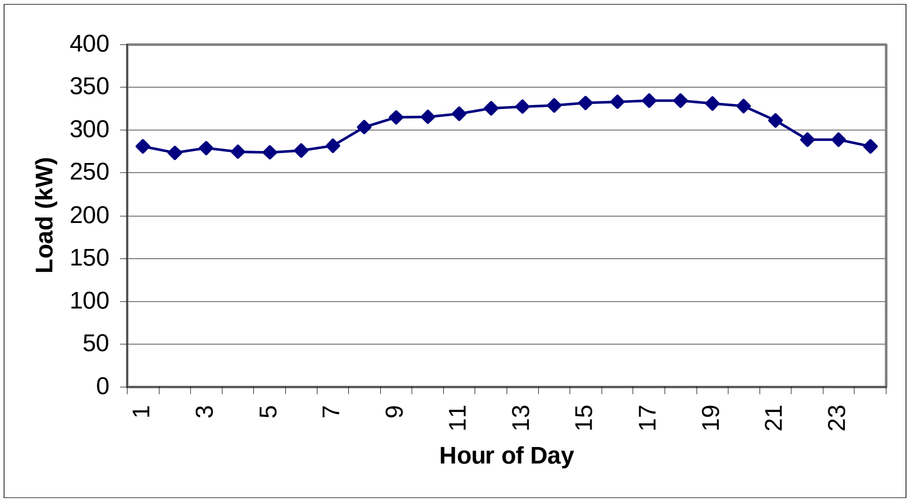

Figure 1. January Peak Day Load Profile for Grocery

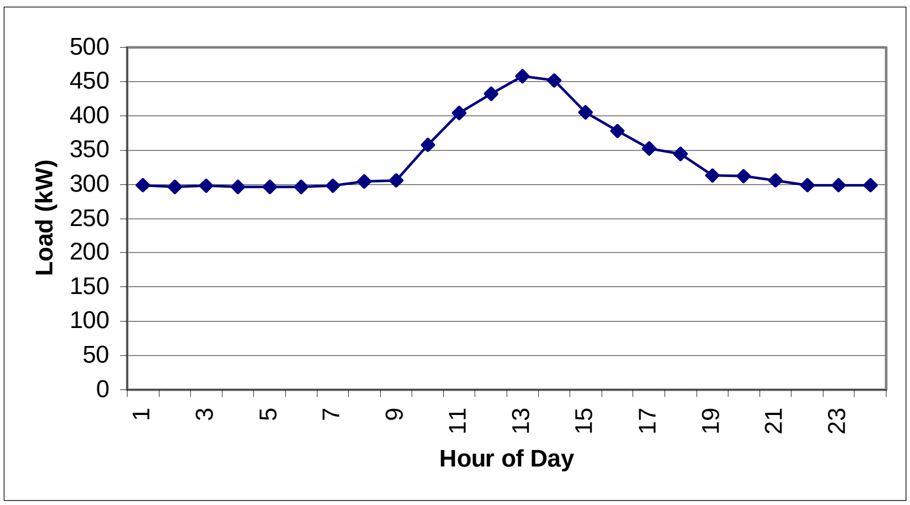

Figure 2. August Peak Day Load Profile for Grocery

3.2 SCE Tariff and CalPX Prices

Customers purchasing electricity from their disco are assumed to do so under established 1999 tariffs. In this study, three publicly available tariff rates for commercial customer types are used (see Table 1), depending on the size of the customer's peak load. For each tariff type, a monthly-ratcheted power charge and an energy charge are imposed and vary by season (where summer months are June through September, inclusive), and load period (on-peak, mid-peak, and off-peak) are defined differently under each. In addition, a fixed charge per customer per month is levied (see Table 2).[8]

Table 1. SCE Tariff Information

Tariff	Season	Load Period	Power Charge (US$/kW)	Energy Charge (US$/kWh)
TOU2A	summer	on	7.75	0.23201
TOU2A	summer	mid	2.45	0.06613
TOU2A	summer	off	0.00	0.04271
TOU2A	winter	on	0.00	0.00000
TOU2A	winter	mid	0.00	0.07811
TOU2A	winter	off	0.00	0.04271
TOU2B	summer	on	16.40	0.14896
TOU2B	summer	mid	2.45	0.06613
TOU2B	summer	off	0.00	0.04271
TOU2B	winter	on	0.00	0.00000
TOU2B	winter	mid	0.00	0.07811
TOU2B	winter	off	0.00	0.04271
TOU8	summer	on	17.55	0.09485
TOU8	summer	mid	2.80	0.05989
TOU8	summer	off	0.00	0.03810
TOU8	winter	on	0.00	0.00000
TOU8	winter	mid	0.00	0.07336
TOU8	winter	off	0.00	0.03925

Table 2. SCE Fixed Customer Charges

Tariff Type	Customer Charge (US$/month)	Stand-by Charge (US$/kW/month)
TOU2A	79.95	5.40
TOU2B	79.95	5.40
TOU8	298.65	6.40

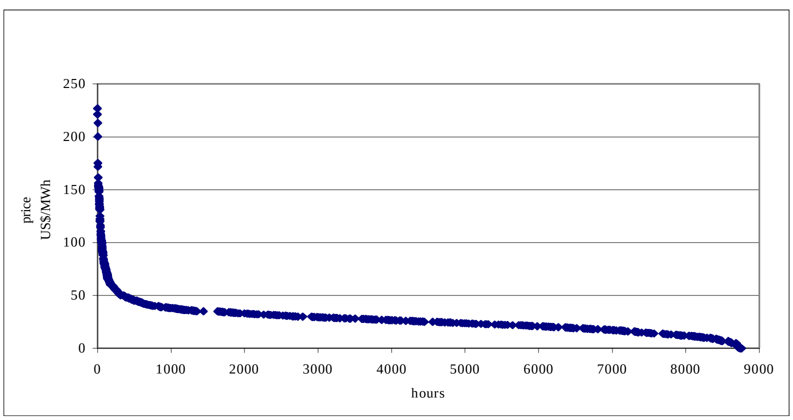

Figure 3. CalPX Day-Ahead Constrained Market Price Duration Curve for 1999 (Source: CalPX)

Customers who install DER may have the option of selling surplus electricity back into the grid at the competitive price. For California, this generally refers to the day-ahead (DA) constrained (i.e., accounting for congestion) equilibrium price in the CalPX. Since the California grid is essentially

[8] In the U.S. peak power charges are usually called *demand charges.*

divided into two zones, north of Path 15 (NP15) and south of Path 15 (SP15), customers in this study receive the appropriate SP15 CalPX DA constrained price for any sales to the grid. The price duration curve for this market (see Figure 3) shows a rather well functioning market in 1999, with high prices (> US$50/MWh) occurring for only about 300 hours.

3.3 Generating Technology Data

The generating technologies available to the customers are listed in Table 3 along with their operating characteristics. The technologies with labels *ROZJ* or *ROZD* are diesel generators manufactured by Kohler. Those labelled *mT_P* or *mT_Cap* are microturbines, manufactured by General Electric (formerly Honeywell) and Capstone, respectively. The rest of the technologies are various brands of fuel cells. Fuel 2 is diesel and fuel 1 is natural gas.

Table 3. Candidate DER Technologies

Technology	Plate (kW)	Lifetime (years)	Turnkey Cost (US$/kW)	OMFix (US$/kW/year)	OMVar (US$/kWh)	Heat Rate (kJ/kWh)	Fuel
20ROZJ	25	10	487	0	0.000	42709.6	2
30ROZJ	33	10	398	0	0.000	43414.1	2
40ROZJ	40	10	373	0	0.000	38181.9	2
50ROZJ	55	10	309	0	0.000	40055.6	2
60ROZJ	62	10	299	0	0.000	37931.2	2
80ROZJ	80	10	258	0	0.000	41560.8	2
100ROZJ	100	10	232	0	0.000	37844.0	2
135ROZJ	135	10	206	0	0.000	40146.6	2
150ROZJ	153	10	195	0	0.000	35776.9	2
180ROZJ	185	10	174	0	0.000	37917.0	2
200ROZD	200	10	175	0	0.000	39128.0	2
230ROZD	230	10	159	0	0.000	10224.9	2
250ROZD	250	10	159	0	0.000	10055.7	2
275ROZD	275	10	159	0	0.000	9977.0	2
300ROZD	300	10	153	0	0.000	9821.4	2
350ROZD	350	10	146	0	0.000	9847.2	2
400ROZD	400	10	161	0	0.000	10204.4	2
450ROZD	450	10	162	0	0.000	37183.2	2
500ROZD	500	10	160	0	0.000	38546.8	2
600ROZD	600	10	165	0	0.000	38181.9	2
DAIS	10	5	500	200	0.015	10000.0	1
FCEnergy	250	5	4000	200	0.015	8000.0	1
H-Power	10	5	600	200	0.015	10550.0	1
ONSI-P	200	5	3310	200	0.015	10002.0	1
mT_P	75	10	650	0	0.007	12000.0	1
mT_Cap	28	10	1,240	0	0.010	13846.0	1
SOFCo	10	5	1250	0	0.015	7991.0	1
SOFCo	52.5	5	1250	0	0.015	7991.0	1
TMI	100	5	1194	100	0.015	7994.0	1

4. Results

In order to insure that our analysis is robust, it is performed under various regulatory and economic conditions, summarized by Table 4.

In Figure 4, the grocery's on-site hourly output generation during peak days of each month are presented. The pattern is very consistent in this case. The store is self-sufficient, even on these peak days, for much of the time. Only during the afternoon and evening does its load exceed the installed on-site capacity of 312 kW, which is a mixture of fuel cells and microturbines. As can been seen from Figures 1 and 2, therefore, the grocery store only a few kW during the winter season, but up to about 150 kW at its summer peak. In other words, the grocery, like virtually all cases analysed, self provides its base and shoulder requirement, but buys its peak requirement, even though this is clearly the expensive electricity. The distribution company ends up delivering much less energy to this customer and accommodating a much lower load factor on its equipment.

Table 4. Operating Scenarios and Sensitivities for Purchasing Electricity

Operating Scenarios and Sensitivities	Description
PXRN (CalPX and revenue neutrality)	In this base scenario the customers can buy all of their electricity at the CalPX price, but they also have to pay an extra fee in order to achieve revenue neutrality for the disco (compared with the tariff scenario, described next).
Tariff	In this scenario, the customer buys all of its electricity from the disco at an established tariff structure.
Fixed Rate (Frate)	The customer buys all of its electricity at a fixed tariff. It pays the same during all months.
PXRN-Sales (Free Sales)	This is the similar to the first scenario, but now, the customer can sell its electricity at the PX price.[9]
10Turnkey	Customers face a 10% increase in turnkey costs of fuel cells.
50Turnkey	Customers face a 50% increase in turnkey costs of fuel cells.
HighNatG	Customers face natural gas prices that are 40% higher than the base case (US$4.20/GJ).
LowNatG	Customers face natural gas prices that are 40% lowe than the base case
Standby C.	Stand-by charges are applied to all consumers.
IntRate	The interest rate is increased to 9.5% from 7.5%.

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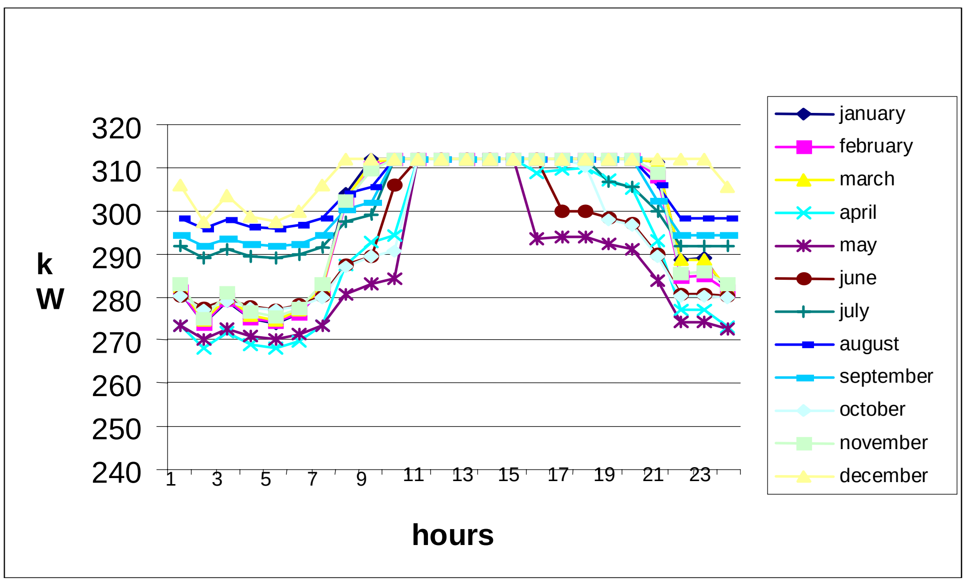

Figure 4. Grocery PXRN Total Output Generation During Peak Hours

Figure 5 shows a summary of the results from the modelling the five commercial customers. Specifically, the installation of distributed generation technology results in significant savings over

[9] In other scenarios, sales are not allowed at the same time as purchases, although any excess generation can be sold.

the *do-nothing* scenario[10]. These savings are significant across all customers and situations. Furthermore, customers acting together as a microgrid are able to realise somewhat greater savings due to their ability to take advantage of economies of scale. Figure 6 and Figure 7 indicate that customers acquire most of their peak demand and consumed energy, respectively, through installed capacity

The model estimates that there are modest efficiency gains to be had from joining or forming a microgrid. However, there are no situations in which customers choose to disconnect entirely from the grid, although in some cases, customers cover over 90% of their energy needs through on-site installed capacity. For future research, we hope to enrich the model by having more recent competitive price data and ancillary service and demand-side markets into which customers can sell capacity that would not be used for on-site energy needs, and to incorporate the benefits of combined heat and power applications.

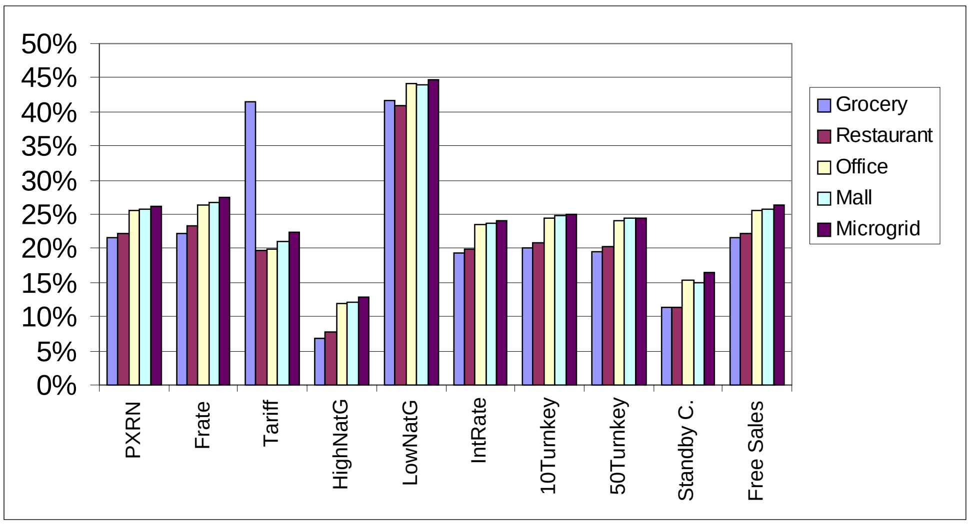

Figure 5. Savings Over a "Do-Nothing" Case

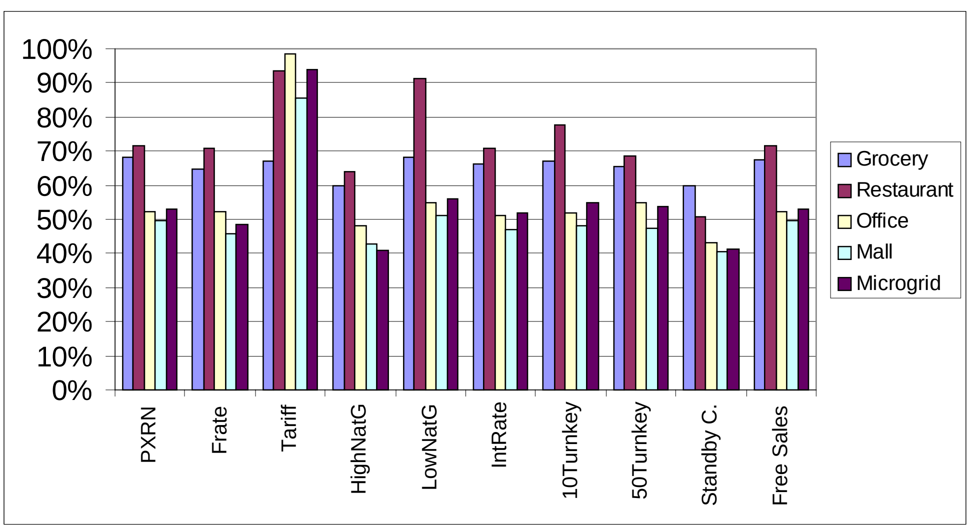

Figure 6. Percent Coverage of Peak Demand through Installed Capacity

[10] A situation in which the customer simply meets all of its electricity needs through the disco and makes no installation of its own.

One standout result of Figures 5 and 6 is that under the Tariff scenario installed capacity is high, while energy production is low, compared to the other scenarios. The reason for this is the stiff power charge. Since this has such a dominant effect on customer bills, more DER capacity is installed; however, since it is being bought for capacity reasons, the cheapest capital cost technologies are chosen, mostly diesel generators. Because these have poor energy conversion efficiency characteristics, they are less competitive with disco power and are used less than other technologies. This is an interesting result in that it demonstrates two features of the analysis: first, the use of the revenue neutrality adder to the CalPX price dampens it considerably, with the result that the demand charge creates more artificial price volatility than actually occurs in the open market; and second, tariff structures, which are often heavily influenced by government policy, can have a dramatic effect on technology choice.

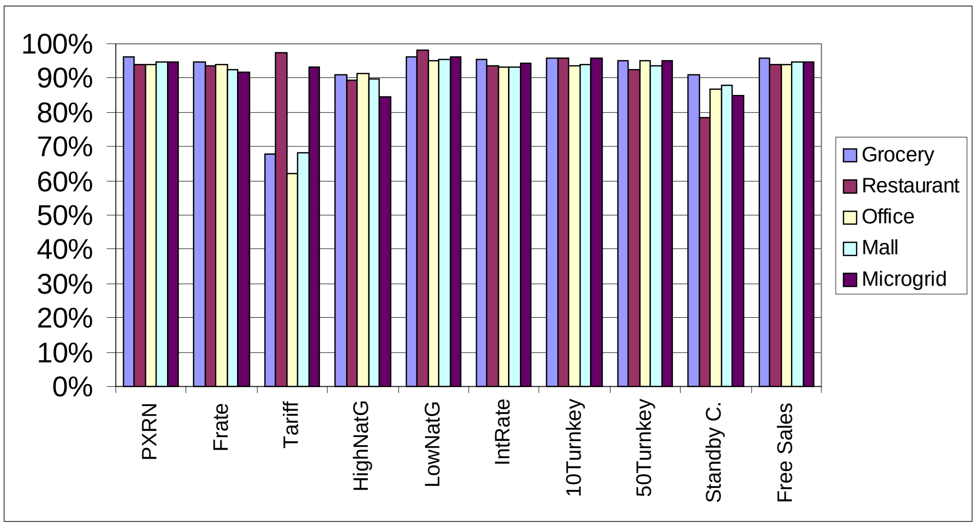

Figure 7. Percent Coverage of Energy Consumption through Installed DER Capacity

Regarding technology choice, fuel cells appear highly attractive and tend to dominate installed DER generation, while some microturbines are also chosen. Fuel cells are used in a baseload role and microturbines are used as peaking units, while high peak loads are supplied by purchases from the grid. This outcome is not surprising and is quite similar to typical results in utility-scale power systems, where capital-intensive generation dominates baseload roles and vice-versa.

5. Conclusions

Improvements in small scale generating technologies together with the limitations of the existing macrogrid and customer desire to better match PQR to enduse loads will spur the growth of on-site generation. This generation can be clustered with loads into local semi-autonomous microgrids. CERTS conducts an ongoing research program intended to solve the electrical engineering problems and facilitate wide development of microgrids. Berkeley Lab is developing DER-CAM to predict the patterns of DER adoption and direct research towards the key problems.

Early DER-CAM results show that typical commercial customers adopt on-site generation under all scenarios tested. Typical annual electricity cost savings for the customers is about 20-25%. Fuel cells are attractive under the assumptions used, but manufacturer cost claims are most likely overly optimistic. Customers typically self provide a significant share of their electricity requirement, often over 90%, while installed capacity tends to provide only about 50-70% of peak load. In other words, on-site generation tends to fill a baseload role, and the customers buy power at their peaks rather than installing their own generation. The resulting residual load, as seen by the grid, therefore, tends to be much smaller than without DER in place, but has a much lower load factor. This result is not surprising because self-providing near the peak becomes unattractively expensive for a customer, just as it does on utility scale systems. But, the outcome is undesirable from the point of view of the disco, which provides much lower capacity factor capability. In no case does the customer meet its own peak, that is, it never disconnects entirely from the grid.

In ongoing work, more reliable data are being collected, and other options available to the customers, such as participation in ancillary services markets and CHP are being introduced into the model. Finally, some renewable energy alternatives are being introduced.

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